# COOPERATIVE MINNESOTA TECHNICAL INTERCONNECTION AND INTEROPERABILTY REQUIREMENTS

TIIR

Abstract

The technical requirements for interconnection of Distributed Energy Resources to the distribution system to be used in conjunction with electric utilities' Technical Specification Manuals

# Contents

# 1. Overview

## 1.1 General

Distributed Energy Resources (DER) connected to the electric distribution system span a wide range of sizes and electrical characteristics utilizing technology that is constantly evolving. The design of electrical distribution systems varies widely from that which is required to serve the rural customer to that which is needed to serve the large commercial customer.

The electric distribution system is designed to operate in both normal and contingency configurations. Normal system configurations or normal operation exists when all distribution facilities and equipment are available and fully functional and the Area EPS's switches are in their normal state. Contingency system configuration or contingency operation is the condition in which the failure of a single or multiple element(s) affect the normal operation of the Area EPS or when the Area EPS's switch positions are in the abnormal state. Contingency configurations can arise from electric component failures or from planned maintenance.

The scope of this document, referred to as the Technical Interconnection and Interoperability Requirements (TIIR), is to describe common statewide requirements for interconnection of DER systems with the Area EPS. The Area EPS's specific specifications or technology requirements are detailed with the Area EPS Operator's Technical Specification Manual (TSM). Both the TIIR and the TSM documents are based upon the IEEE 1547 standards and other applicable national standards. The intent of these documents is to provide consumers and installers with a clear set of technical requirements and guide the interconnection of DER systems with the local electrical distribution system using a safe, reliable, and cost-effective design.

With so many variations in Area EPS designs, it becomes complex to create a single set of interconnection requirements that fits all DER interconnection situations. The Area EPS Operator must maintain a level of engineering judgment in order to interconnect the wide range of technologies over a variety of Area EPS and DER characteristics and designs[1]. The Area EPS Operator shall follow applicable industry standards and good utility practice when applying engineering judgment.

This document sets forth statewide technical requirements for DER interconnecting to an Area EPS in the state of Minnesota. The Minnesota statewide TIIR have been established to align with the Area EPS Operators' duty and obligation to plan and operate a distribution system that economically delivers electric power while focusing on safety, reliability, and quality of service.

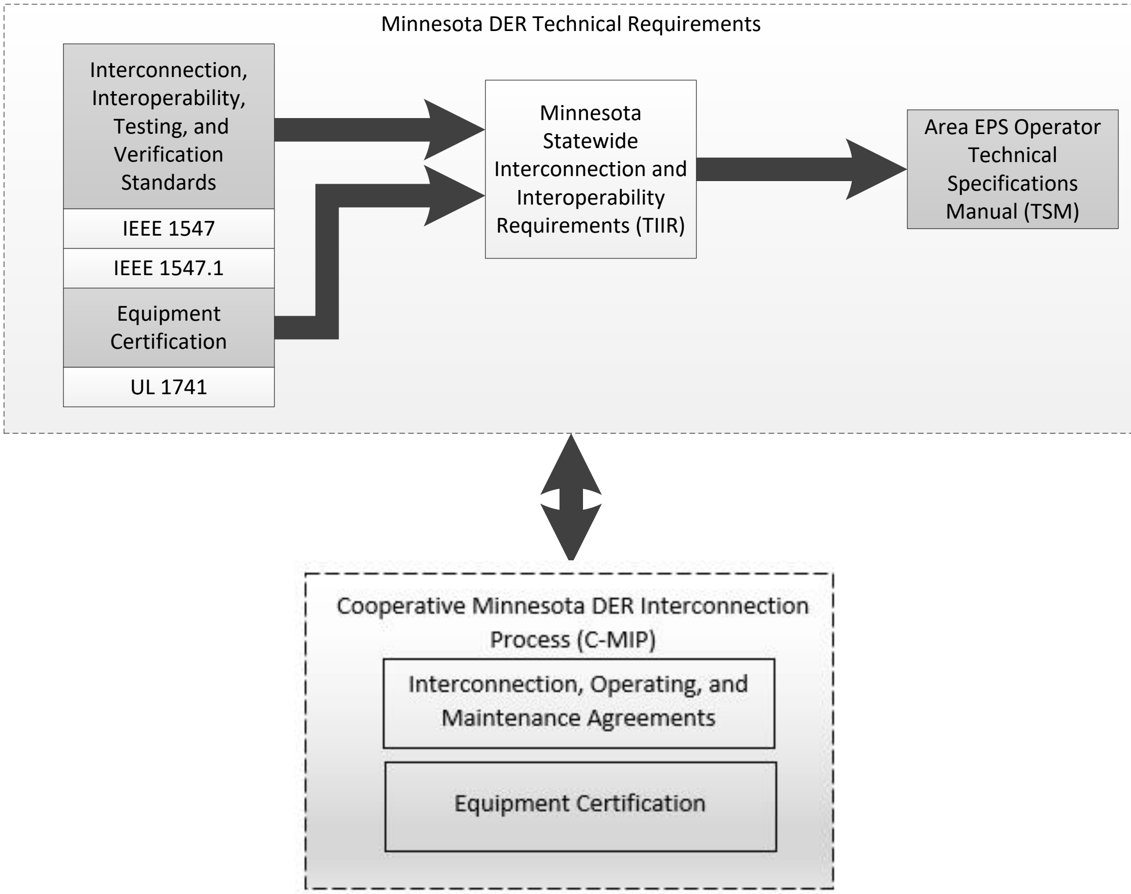
[1] Another factor driving the need for engineering judgment is the increasingly varied mixture of legacy DER equipment from different era standards. Currently national standards do not exist to address interconnection engineering considerations that may arise due the mix of current and legacy technology. For example, a portion of the Area EPS with legacy inverters and advanced inverters will respond differently to abnormal conditions when compared to apportion of the Area EPS that contains only advanced inverters. Legacy inverters are grandfathered in under the standards under which they were installed.

Cooperative electric associations in the state of Minnesota have adopted the substance of the Minnesota Public Utilities Commission adopted TIIR (Docket E999/CI-16-521) with minor edits referencing the Cooperative Minnesota Distributed Energy Resource Interconnection Process (C-MIP) instead of the Minnesota Distributed Energy Resource Interconnection (MN DIP).

The statewide TIIR shall be used in conjunction with individual Area EPS Operator interconnection Technical Specification Manuals (TSM). Where industry standards exist, the TSM shall align with the applicable standards including IEEE 1547. The TSM also lists the Area EPS Operator specific requirements and provides further detail in areas where no common statewide or national industry standards exist[2]. In addition to allowing for differences in distribution electric and information systems design and operation, the Area EPS Operator's TSM allows for expedited adoption of new industry standards and best practices as they become available without creating conditions where the statewide interconnection standards and national standards become out-of-sync. Figure 1 depicts the interaction of key DER industry technical standards, statewide technical standards (TIIR), Area EPS Operator's technical specifications manuals (TSMs), and the Cooperative Minnesota Distributed Energy Resources Interconnection Process (C-MIP)[3].

[2] For example, industry standards do not define conditions or size thresholds for when metering, interoperability, protection, or other requirements shall be applied. Also, interconnection standards only address the electrical and interoperability interface between the Local EPS and Area EPS.
[3] The Cooperative Minnesota Distributed Energy Resource Interconnection Process (C-MIP) is similar in construct to the Minnesota Public Utilities Commission adopted Minnesota Distributed Energy Resource Interconnection Process (MN DIP).

*Figure 1. Interaction of DER Standards*




All requirements in the most recent versions of IEEE 1547 and 1547.1 are adopted by the TIIR. IEEE 1547, *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*, and IEEE 1547.1, *IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems*, provides the foundation of interconnection and interoperability technical requirements which applies to all DER interconnections. Other standards, recommended practices, and guide documents may be applicable to individual projects and should be referenced based on the DER technology and configuration being proposed and characteristics of the Area EPS[4] to which it is being interconnected. In general, the content of industry standards is not reproduced here, but instead the additional standards are referenced in Section 3 of this document.

Consistent with IEEE 1547, these requirements apply to the interconnection of all DER units within the Local EPS that parallel with the Area EPS. The requirements in the TIIR shall be applied at the Reference Point of Applicability (RPA)[5], unless otherwise specified by the

[4] For example, low voltage secondary networks have unique interconnection concerns and the recommended practice in IEEE 1547.6 should be used in conjunction with IEEE 1547 and IEEE 1547.1.

[5] See IEEE 1547 and the TIIR Annex A for further information on the RPA. The RPA is the point at which IEEE 1547 interconnection and interoperability requirements are required to be met.

TIIR or mutually agreed upon. The DER shall not create or contribute to an intentional Area EPS island, unless approved by the Area EPS Operator.

When the need arises, the Area EPS should coordinate with Transmission Providers and Regional Transmission Operators to accommodate requests from these entities which cross the transmission and distribution electric interface while still maintaining the Area EPS Operators' primary responsibility of providing safe, reliable, and quality service for Area EPS retail customers.

Protection systems requirements in the TIIR, are structured to protect the Area EPS, Area EPS customers, and the public. Details of protection systems requirements are specified in the Area EPS Operator's TSM. The protection of the DER and the Local EPS is solely the responsibility of the Interconnection Customer and is not addressed in these technical requirements.

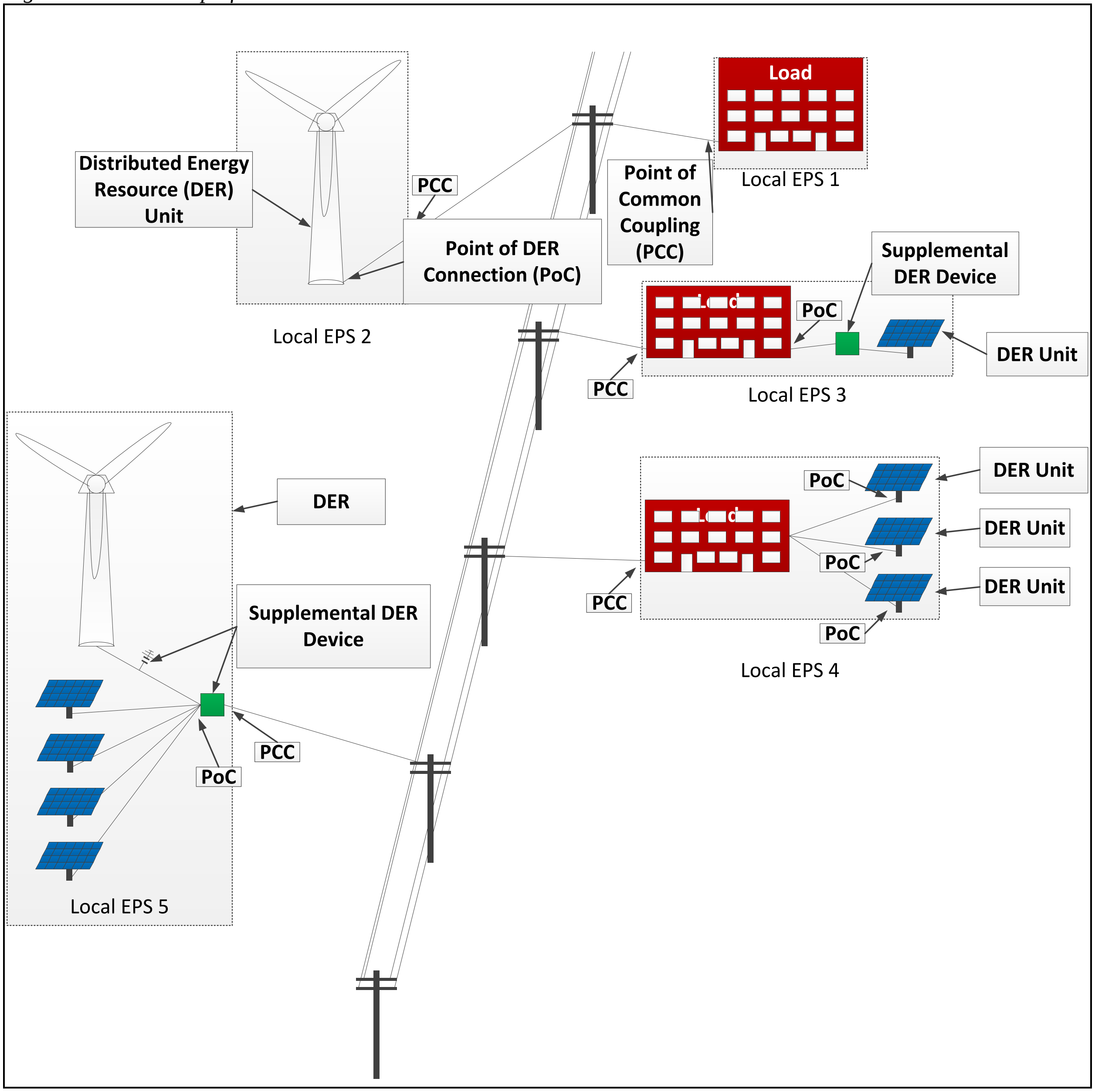
The DER Operator shall be responsible for complying with all applicable local, independent, state and federal codes such as building codes, National Electric Code (NEC), National Electrical Safety Code (NESC) and local municipality noise and emissions standards. As required by Minnesota State law (326B.36 Subd. 5 Duty of Electrical Utility), the Area EPS may require proof of complying with the National Electrical Code before the interconnection is completed, through approval by an electrical inspector recognized by the Minnesota State Board of Electricity. The DER Operator shall maintain the DER facilities using industry standards and best practices in order to reduce the likelihood of an unintended DER operating state causing adverse impacts to customers or the Area EPS.

In the event of an inconsistency between various laws, rules, standards, contracts, or policies over interconnection requirements, the resolution to this inconsistency shall be resolved by assigning an order of precedence from highest to lowest as follows:

1. State of Minnesota statutes
2. Minnesota Public Utilities Commission approved standards, tariffs or orders applicable to cooperative electric associations
3. National Standards, Codes, and Certifications
4. Agreements between the Area EPS Operator and the DER Operator
5. Area EPS Operator published documents

Figure 2 contains a depiction and description of the relationship of some key terms used throughout this document. The usage of these terms as it relates to Figure 2 is consistent with IEEE 1547 definitions. Each of the terms are defined in Section 3-B of this document. Additional discussion of the terms is found in Annex B.

*Figure 2. Relationship of Terms*



## 1.2 Scope

The statewide TIIR applies to all DER technology sized at 10 MW and less in AC nameplate capacity[6] that is interconnected at secondary or primary distribution voltages and is operated in parallel[7] with an Area EPS. The TIIR applies to DER for any duration of parallel operation. Non-exporting DER that operate in parallel with the Area EPS are subject to these technical standards.

## 1.3 Purpose

This TIIR document provides the technical requirements common to cooperative electric association in Minnesota for the interconnection and interoperability of DER with associated Area EPS. It provides references and requirements relevant to safety, security, performance, operation, interoperability, testing and verification in harmony with other industry, national and state standards.

## 1.4 Coordination with Area EPS Operator's Specific Technical Standards

Where this TIIR document does not provide technical guidance, the Interconnection Customer needs to review the Area EPS Operator's specific TSM document, the Area EPS Operator's web site or contact the generation interconnection coordinator at the Area EPS Operator. The following is a brief listing of some of the areas which further technical guidance is to be provided within the Area EPS Operator's TSM.[8]

1) Project Coordination Information
2) Protection system requirements for the DER interconnection
3) Operational standards and requirements
4) DER monitoring and communication requirements
5) Metering requirements in support of specific rates and operational needs

The Area EPS Operator's TSM documents are to be designed to provide utility specific details aligned with the TIIR requirements. The Area EPS Operators' TSM document shall be limited to detailing requirements which are in support of the requirements contained within the TIIR and C-MIP. Additional requirements not contemplated by the TIIR may be mutually agreed upon between the Parties**.**

At the time this document is being written, IEEE 1547.1 is undergoing a revision which is expected to significantly affect requirements surrounding DER testing and verification. The publication of the updated IEEE 1547.1 standard may necessitate updating this document soon thereafter, most notably addressing changes to Section 12.

[6] The 10 MW AC nameplate capacity limitation is based on Minn. Stat.§ 216B.1611.

[7] National Electric Code and Area EPS specific requirements apply for standby generators and emergency back-up generators with, a break-before-make type of interconnection.

[8] See Annex B for the list of additional topics in a TSM.

### 1.5 Convention for Word Usage

Throughout this document, the word *shall* is used to indicate a mandatory requirement. The word *should* is used is used to indicate a recommendation. The word *may* is used to indicate a permissible action. The word *can* is used for statements of capability and possibility.

### 1.6 Transition Period

All requirements of the TIIR are immediately applicable unless requiring equipment that conforms with IEEE 1547-2018 advanced functionalities.

Area EPS Operators cannot require the use of certified equipment that meets the requirements of IEEE 1547-2018 until such time the equipment is readily available. At such time certified equipment first becomes available, the Area EPS Operator and DER Owner may mutually agree to utilize the certified equipment and functionalities in conformance with the requirements of IEEE 1547-2018. At such time when certified equipment is readily available[9], the entire TIIR shall be applicable.

## 2. References

The standards, codes, certification, guides and recommended practices listed in this section are active as of the publication of this document. These standards, codes, certifications, guides and recommended practices may be superseded, withdrawn, or additional applicable revisions may become available after the publication of this document. Later revisions of the technical references listed below may be available and supersede the versions referenced in this document. At the time an interconnection application is submitted, the Area EPS Operator and the DER Operator shall use the most recent applicable technical reference. Application of industry standards, codes, certifications, guides and recommended practices shall be consistent with the standard governing body’s manuals, policies, and procedures.

IEC TR 61000-3-7:2008, Electromagnetic compatibility (EMC) - Part 3-7: Limits - Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems.

IEC 61000-4-3:2006+A1:2007+A2:2010, Electromagnetic compatibility (EMC) - Part 4-3: Testing and measurement techniques - Radiated, radio-frequency, electromagnetic field immunity test.

IEC 61000-4-5:2014+A1:2017, Electromagnetic compatibility (EMC) - Part 4-5: Testing and measurement techniques – Surge immunity test.

IEEE Std 1547-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

IEEE Std 1547.1, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

[9] Refer to UL 1741 for timeline of readily available certified equipment that meets the requirements of IEEE 1547-2018.

IEEE Std 1547.2, Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems

IEEE Std 1547.3-2007, Guide for Monitoring Information Exchange and Control of DR Interconnected with Electric Power Systems

IEEE Std 1547.4-2011, IEEE Guide for Design, Operation, and Integration of Distributed Resource Island System with Electric Power Systems

IEEE Std 1547.6-2011, IEEE Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks

IEEE Std 1547.7-2013, IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection

IEEE Std 519-2014, IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems

IEEE Std 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installation on Power Systems

IEEE Std 1453.1-2012 (Adoption of IEC/TR 61000-3-7:2008) - IEEE Guide--Adoption of IEC/TR 61000-3-7:2008, Electromagnetic compatibility (EMC)--Limits--Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems

IEEE Std C37.90-2005, IEEE Standard for Relay Systems Associated with Electric Power Apparatus

IEEE Std C37.90.1-2012, IEEE Standard Surge Withstand Capability (SEC) Tests for Protective Relays and Relay Systems Associated with Electric Power Apparatus

IEEE Std C37.90.2-2004, IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE C37.95-2014, IEEE Guide for Protective Relaying of Utility-Consumer Interconnections

IEEE Std C50.12-2005, IEEE Standard for Salient-Pole 50 Hz and 60 Hz Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications Rated 5 MVA and Above.

IEEE Std C50.13-2014, IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above.

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.42-2016, Guide for the Application of Component Surge-Protective Devices for Use in Low-Voltage [Equal to or Less than 1000 V (ac) Or 1200 V (dc)] Circuits

IEEE Std C62.45-2002, IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000 V and Less) AC Power Circuits.

IEEE Std C62.92.2-2017, IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Part II – Grounding of Synchronous Generator Systems

IEEE Std C62.92.6-2017, IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Pat VI

IEEE Std 32-1972 (Reaff 1990), IEEE Standard Requirements, Terminology, and Test Procedure for Neutral Grounding Devices

IEEE Std 141-1993, IEEE Recommended Practice for Electric Power Distribution for Industrial Plants – Red Book

IEEE Std 142-2007, IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems – Green Book

IEEE Std 242-2001, Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems

IEEE Std 446-1995, Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications

IEEE Std 2030-2011, Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power System (EPS), End-Use Applications, and Loads

IEEE Std 2030.5-2013, IEEE Adoption of Smart Energy Profile 2.0 Application Protocol Standard.

IEEE Std 1815-2012, IEEE Standard for Electric Power Systems Communications-Distributed Network Protocol (DNP3)

ANSI C84.1-2016, Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

UL 1741, Inverters, Converters, and Controllers for use in Independent Power Systems

ANSI C2-2007, National Electrical Safety Code", Published by the Institute of Electrical and Electronics Engineers, Inc.

NFPA 70, National Electrical Code", Published by the National Fire Protection Association

IEC 61850-7-420:2009, Communication networks and systems for power utility automation - Part 7-420: Basic communication structure - Distributed energy resources logical nodes

IEC 62351-12:2016, Power systems management and associated information exchange - Data and communications security - Part 12: Resilience and security recommendations for power systems with distributed energy resources (DER) cyber-physical systems

# 3. Definitions and Acronyms

## 3.1 General

The definitions of terms used in this document are consistent with the IEEE 1547, IEEE 1547.1, and Minnesota DER Interconnection Process definitions, to the extent possible.

The origins of definitions are noted below in Table 1. The associated symbols are shown as a superscript to each term in order to denote the document from which the definition originates. For the purpose of denoting origin, the definition notes are to be considered part of the definition unless otherwise denoted with a separate symbol.

*Table 1. Origin of Defined Terms*

| Document of origin for definition | Symbol |
|---|---|
| IEEE 1547-2018 | x |
| Cooperative Minnesota DER Interconnection Process (C-MIP) - 2019 | ʌ |
| Cooperative Minnesota Interconnection Technical Standards (TIIR) | Γ |
| Other (additional footnote is shown to denote origin) | ɵ |

## 3.2 Definitions

**Abnormal Operating Performance Category[x]:** The grouping for a set of requirements that specify technical capabilities and settings for a DER under abnormal operating conditions, i.e., outside the *continuous operation* region.

**Area Electric Power System (Area EPS) [ʌ]:** The electric power distribution system connected at the Point of Common Coupling.

**Area Electric Power System Operator (Area EPS Operator) [ʌ]:** An entity that owns, controls, or operates the electric power distribution systems that are used for the provision of electric service in Minnesota.

**Area EPS Operator Technical Specification Manual (TSM)[Γ]:** The Area EPS Operator's technical manual containing interconnection and interoperability requirements specific to the Area EPS. The TSM is considered part of the Minnesota technical requirements framework.

**Affected Systems[ʌ]:** Another Area EPS Operator's System, Transmission Owner's Transmission System, or Transmission System connected generation which may be affected by the proposed interconnection.

**Authority Governing Interconnection Requirements (AGIR)[x]:** A cognizant and responsible entity that defines, codifies, communicates, administers, and enforces the policies and procedures for allowing electrical interconnection of DER to the Area EPS. This may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc. The degree of AGIR involvement will vary in scope of application and level of enforcement across jurisdictional boundaries. This authority may be delegated by the cognizant and responsible entity to the Area EPS operator or *bulk power system* operator.

> NOTE—Decisions made by an authority governing interconnection requirements should consider various stakeholder interests, including but not limited to Load Customers, *Area EPS operators*, *DER operators*, and *bulk power system* operator.

**Bulk Power System (BPS) [x]:** Any electric generation resources, transmission lines, interconnections with neighboring systems, and associated equipment.

NOTE [θ] [10] – The usage of BPS in this document is intended to be generally aligned with the NERC definition of bulk electric systems, which includes transmission facilities with rated voltages above 100 kV; generating units with individual nameplate ratings above 25 MVA with a common point of connection a voltage at 100 kV or above; and generating plants with total capacity ratings above 75 MVA with a common point of connection at 100 kV and above. The term Transmission Power System is used to describe the remaining transmission facilities that are rated for voltages less than 100 kV.

**Cease to Energize[x]:** Cessation of active power delivery under steady state and transient conditions and limitation of reactive power exchange.

NOTE 1—This may lead to momentary cessation or trip.

NOTE 2—This does not necessarily imply, nor exclude, disconnection, isolation, or a trip.

NOTE 3—Limited reactive power exchange may continue as specified, e.g., through filter banks.

NOTE 4—Energy storage systems are allowed to continue charging but are allowed to cease from actively charging when the maximum state of charge (maximum stored energy) has been achieved.

**Certified Equipment[^]:** UL 1741 listing is a common form of DER inverter certification. See C-MIP Process Overview Section 14 Certification of DER Equipment and Section 15 Certification Codes and Standards.

**Cooperative Minnesota DER Interconnection Agreement (Interconnection Agreement)[^]:** The Cooperative Minnesota Distributed Energy Resource Interconnection Agreement. See C-MIP Process Overview Section 8.2 for when the Uniform Contract or the Interconnection Agreement applies.

**Cooperative Minnesota DER Interconnection Process (C-MIP)[^]:** The Cooperative Minnesota Distributed Energy Resource Interconnection Process which is statewide interconnection standards for cooperative electric associations.

**Continuous Operation[x]:** Exchange of current between the DER and an EPS within prescribed behavior while connected to the Area EPS and while the applicable voltage and the system frequency is within specified parameters.

**Continuous Operation Region[x]:** The performance operating region corresponding to *continuous operation.*

**Customers[r]:** Individuals or entities that own a Local EPS that is connected to the Area EPS with the purpose of purchasing electric power service from the Area EPS Operator

**Distributed Energy Resource (DER) [x]:** a source of electric power that is not directly connected to a bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER.

[10] The note associated with BPS is intended to be largely aligned with the NERC definition. This is intended to supplement the definition of IEEE 1547 to reduce confusion since the NERC definition is a subset of the IEEE 1547 definition. A new definition, Transmission Power System is introduced in the section to cover the remaining facilities (i.e. < 100 kV transmission lines).

NOTE 1—Controllable loads used for demand response are not included in the definition of DER.

NOTE 2[r]—See C-MIP Process Overview Section 13 Glossary or Figure 2 in IEEE 1547-2018.

**Distributed Energy Resource Operator (DER Operator)** [x]**:** The entity responsible for operating and maintaining the distributed energy resource.

**Distribution Energy Resource Unit (DER Unit)** [x]**:** An individual DER device inside a group of DER that collectively forms a system.

**Electric Power System (EPS)** [x]**:** Facilities that deliver electric power to a load.

NOTE [r] —This may include generation units. See C-MIP Process Overview Section 13 Glossary or Figure 2 in IEEE 1547-2018.

**Energize**[x]**:** Active power outflow of the DER to an EPS under any conditions (e.g., steady state and transient).

**Energy Storage System (ESS)**[r] **:** An electric system that stores active power for later injection into the Local EPS or Area EPS.

**ESS Control Mode**[r]**:** The function that manages the real and reactive power flow from or to an ESS in response to certain parameters, (such as time, price signals, frequency or external signals, etc.)

**Enter Service**[x]**:** Begin operation of the DER with an energized Area EPS.

**Intentional Island**[x]**:** A planned electrical island that is capable of being energized by one or more Local EPSs. These (1) have DER(s) and load, (2) have the ability to disconnect from and to parallel with the Area EPS, (3) include one or more Local EPS(s), and (4) are intentionally planned.

NOTE—An intentional island may be an *intentional Area EPS island* or an *intentional Local EPS island* (also: “facility island”).

**Interconnection**[x]**:** The result of the process of adding DER to an Area EPS, whether directly or via intermediate Local EPS facilities.

**Interconnection Agreement**[^]: The terms and conditions between the Area EPS Operator and Interconnection Customer (Parties). See C-MIP Process Overview Section 8.2 for when the Uniform Contract or the C-MIP Interconnection Agreement applies.

**Interconnection Customer**[^]**:** The person or entity, including the Area EPS Operator, whom will be the owner of the DER that proposes to interconnect a DER(s) with the Area EPS Operator’s Distribution System. The Interconnection Customer is responsible for ensuring the DER(s) is designed, operated and maintained in compliance with the Minnesota Technical Requirements.

**Interconnection Facilities** [^] – The Area EPS Operator’s Interconnection Facilities and the Interconnection Customer’s Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the DER and the Point of Common Coupling, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the DER to the Area EPS Operator’s System. Some examples of Customer Interconnection Facilities include: supplemental DER devices, inverters, and associated wiring and cables up to the Point of DER Connection. Some examples of Area EPS Operator Interconnection Facilities include sole use facilities; such as, line extensions, controls, relays, switches, breakers, transformers and shall not include Distribution Upgrades or Network Upgrades.

**Interconnection System[x]:** The collection of all interconnection and interoperability equipment and functions, taken as a group, used to interconnect a DER to an Area EPS.

**Interface[x]:** An electrical or logical connection from one entity to another that supports one or more energy or data flows implemented with one or more power or data links.

**Interoperability[x]:** The capability of two or more networks, systems, devices, applications, or components to externally exchange and readily use information securely and effectively. (IEEE Std 2030)

**Inverter[x]:** A machine, device, or system that changes direct-current power to alternating-current power.

NOTE[r] - While the classical definition of inverter originating from IEEE 1547 considers power flow in a single direction, the usage of the term in this document indicates potential for bi-directional capabilities. The machine, device, or system can change power from direct-current to alternating-current and the machines, devices, or systems may also have capabilities to change power from alternating-current to direct-current.

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

**Load[x]:** Devices and processes in a local EPS that use electrical energy for utilization, exclusive of devices or processes that store energy but can return some or all of the energy to the local EPS or Area EPS in the future.

**Local DER Communication Interface[x]:** A local interface capable of communicating to support the information exchange requirements specified in this standard for all applicable functions that are supported in the DER.

**Local Electric Power System (Local EPS) [x]:** An EPS contained entirely within a single premises or group of premises.

**Maintenance Requirements [o]:** The maintenance terms and conditions between the Area EPS Operator and Interconnection Customer (Parties) included in the Operating Agreement as Attachment 5 of the Interconnection Agreement.

**Material Modifications [^]:** A modification to machine data, equipment configuration or to the interconnection site of the DER at any time after receiving notification by the Area EPS Operator of a complete Interconnection Application that has a material impact on the cost, timing, or design of any

Interconnection Facilities or Upgrades, or a material impact on the cost, timing or design of any Interconnection Application with a later Queue Position or the safety or reliability of the Area EPS.[11]

**MN Technical Requirements [^]:** The term including all of the DER technical interconnection requirement documents for the state of Minnesota adopted by cooperative electric associations; including: 1) Attachment 2 Distributed Generation Interconnection Requirements established in the Commission's September 28, 2004 Order in E-999/CI-01-1023) until superseded by the June 1, 2020 adoption of updated Cooperative Minnesota DER Technical Interconnection and Interoperability Requirements, (this document).

**Momentary Cessation[x]:** Temporarily *cease to energize* an EPS, while connected to the Area EPS, in response to a disturbance of the *applicable voltages* or the system frequency, with the capability of immediate Restore Output of operations when the applicable voltages and the system frequency returns to within defined ranges.

**Nameplate Ratings[x]:** nominal voltage (V), current (A), maximum active power (kW), apparent power (kVA), and reactive power (kvar) at which a DER is capable of sustained operation.

> NOTE—For Local EPS with multiple DER units, the aggregate DER nameplate rating is equal to the sum of all DERs nameplate rating in the Local EPS, not including aggregate capacity limiting mechanisms such as coincidence factors, plant controller limits, etc., that may be applicable for specific cases.

**Normal Operating Performance Category[x]:** The grouping for a set of requirements that specify technical capabilities and settings for DER under normal operating conditions, i.e., inside the *continuous operation* region.

**Non-export, Non-exporting[Γ]:** When the DER is sized and designed such that the DER output is used for host load only and is designed and operated to prevent the transfer of electrical energy from the DER to an Area EPS or TPS.

**Operating Requirements[^]**: Any operating and technical requirements that may be applicable due to the Transmission Provider's technical requirements or Minnesota Technical Requirements, including those set forth in the C-MIP Interconnection Agreement.

**Parallel Operation[Γ]:** a source operated in parallel with the grid when it is connected to the distribution grid and can supply energy to the customer simultaneously with the Area EPS supply of

[11] A Material Modification shall include, but may not be limited to, a modification from the approved Interconnection Application that: (1) changes the physical location of the point of common coupling; such that it is likely to have an impact on technical review; (2) increases the nameplate rating or output characteristics of the Distributed Energy Resource; (3) changes or replaces generating equipment, such as generator(s), inverter(s), transformers, relaying, controls, etc., and substitutes equipment that is not like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; (4) changes transformer connection(s) or grounding; and/or (5) changes to a certified inverter with different specifications or different inverter control settings or configuration. A Material Modification shall not include a modification from the approved Interconnection Application that: (1) changes the ownership of a Distributed Energy Resource; (2) changes the address of the Distributed Energy Resource, so long as the physical point of common coupling remains the same; (3) changes or replaces generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying, controls, etc. and substitutes equipment that is a like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; and/or (4) increases the DC/AC ratio but does not increase the maximum AC output capability of the Distributed Energy Resource in a way that is likely to have an impact on technical review.

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**Permissive Operation:** Operating mode where the DER performs ride-through either in *mandatory operation* or in *momentary cessation*, in response to a disturbance of the *applicable voltages* or the system frequency.

**Permissive Operation Region:** The performance operating region corresponding to permissive operation.

**Point of Common Coupling (PCC)[x]:** The point of connection between the Area EPS and the Local EPS.

NOTE 1—See C-MIP Process Overview Section 13 Glossary or Figure 2 in IEEE 1547.

NOTE 2—Equivalent, in most cases, to "service point" as specified in the National Electrical Code™ and the National Electrical Safety Code™.

**Point of Distributed Energy Resources Connection (point of DER connection–PoC)[x]:** The point where a DER unit is electrically connected in a Local EPS and meets the requirements of this standard exclusive of any load present in the respective part of the Local EPS.

NOTE 1—See C-MIP Process Overview Section 13 Glossary or Figure 2 in IEEE 1547.

NOTE 2—For (a) DER unit(s) that are not self-sufficient to meet the requirements without (a) supplemental DER device(s), the point of DER connection is the point where the requirements of this standard are met by DER (b) device(s) in conjunction with (c) supplemental DER device(s) exclusive of any load present in the respective part of the Local EPS.

**Power Control[r]:** System that controls the output (production or discharging) and input (charging) of one or more DER in order to limit output, input, export and/or import.

**Range of Allowable Settings[x]:** The range within which settings may be adjusted to values other than the specified default settings.

**Reference Point of Applicability (RPA)[x]:** The location where the interconnection and interoperability performance requirements specified in this standard apply.

**Regional Transmission Operator (RTO)[r]:** The functional entity that maintains the real-time operating reliability of the bulk electric power within a reliability coordinator area.

NOTE – This definition is based on the IEEE 1547 regional reliability coordinator definition. In Minnesota, i.e. the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP), perform this function based on territory.

**Restore Output[x]:** Return operation of the DER to the state prior to the abnormal excursion of voltage or frequency that resulted in a ride-through operation of the DER.

**Return to Service[x]:** Enter service following recovery from a trip.

**Ride-Through[x]:** Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.

**Secondary Network[r]:** An AC distribution system where the low-voltage of the distribution transformers are connected to a common network for supplying electricity directly to consumers. There are two types of secondary networks: grid networks and spot networks.

**Supplemental DER Device[x]:** Any equipment that is used to obtain compliance with some or all of the interconnection requirements of this standard.

> NOTE—Examples include capacitor banks, STATCOMs, harmonic filters that are not part of a DER unit, protection devices, plant controllers, etc.

**Technical Interconnection and Interoperability Requirements (TIIR)[r]:** The supplemental set of DER interconnection and interoperability requirements in this document which together with each Area EPS Operator's Technical Specification Manual (TSM) and industry interconnection standards, make up the Minnesota Technical Requirements.

**Technical Specification Manual (TSM) [r]:** The Area EPS Operator specific interconnection and interoperability requirements for interconnection of Distributed Energy Resources which together with the Technical Interconnection and Interoperability Requirements (TIIR) and industry interconnection standards, make up the Cooperative Minnesota DER Technical Requirements.

**Transmission Power System[r] (TPS):** Any transmission or generation facility that is not part of the bulk power system.

> NOTE - In general, this is transmission facilities rated at voltages less than 100 kV; transmission generation units with power ratings less 25 MVA; and generation plants with total capacity ratings less than 75 MVA.

**Trip[x]:** Inhibition of immediate return to service, which may involve disconnection.

> NOTE—Trip executes or is subsequent to cessation of energization.

**Type Test**[x]: a test of one or more devices manufactured to a certain design to demonstrate, or provide information that can be used to verify, that the design meets the requirements specified in this standard.

## 3.3 Acronyms

| | |
|---|---|
| AGIR | Authority Governing Interconnection Requirements |
| BPS | Bulk Power System |
| C-MIP | Cooperative Minnesota Distributed Energy Resource Interconnection Process |
| DER | Distributed Energy Resource |
| EPS | Electric Power System |
| ESS | Energy Storage System |

| | |
|---|---|
| PoC | Point of Distributed Energy Resource Connection |
| PCC | Point of Common Coupling |
| RPA | Reference Point of Applicability |
| RTO | Regional Transmission Operator |
| TIIR | Technical Interconnection and Interoperability Requirements (this standard document) |
| TPS | Transmission Power System |
| TSM | Technical Specifications Manual (supplemental Area EPS Operator document) |

# 4. Performance Categories

## 4.1 Introduction

The IEEE 1547 standard provides a technology-neutral approach in which performance categories are assigned to specify required capability for reactive power performance, voltage regulation performance, and response to abnormal conditions. Performance categories describe minimum equipment capability and the required ranges of allowable settings. The next two subsections, Performance Category Assignment and Use of Default Parameters, contain the Minnesota specific application requirements based on the available performance categories defined in IEEE 1547 standard.

There are a number of available performance categories defined in IEEE 1547 standard which contemplates current and future system needs at varying levels of DER penetration. Performance requirements associated with performance categories could be driven by Area EPS, TPS or BPS needs. Regional coordination and standardization in selection of abnormal performance categories is necessary. The entity determining the appropriate performance categories is specified by the IEEE 1547 standard. The subsections below contain the specific requirements that have been determined to be appropriate for application in Minnesota.

Category A and B specify reactive power capability and voltage regulation performance requirements. Category B is intended for use where DER penetration is higher and where the DER power output is subject to frequent large variations. Category B encompasses all of Category A capabilities. Category A and B assignment is specified by the Area EPS Operator, Section 4.2.A.

Categories I, II, and III differentiate performance requirements for DER response to abnormal conditions. The Minnesota Public Utilities Commission is delegated authority by the IEEE 1547 standard to provide guidance for assigning abnormal performance categories which is specified in Section 4.2.B. Category III is the highest capability and can inherently meet the ride-through requirements of the lower categories. In contrast, the voltage and frequency trip requirements of higher categories may not be met by lower categories as the range of allowable settings may be mutually exclusive.

I. Category I encompasses minimum BPS essential needs
II. Category II coordinates with North American Electrical Reliability Corporation (NERC) PRC-024-2 with a modification to the voltage ride-through in order to account for characteristics of distribution load devices[12].
III. Category III covers all BPS reliability needs and also introduces ride-through requirements aimed at addressing high DER penetration integration issues such as power quality events and other abnormal system conditions which may arise from DER tripping in the Local EPS.

## 4.2 Performance Category Assignment

Performance Category assignment is specific to the state of Minnesota. Based on IEEE 1547, the Area EPS Operator assigns normal performance categories - Category A and B, as shown in Section 4.2.A. The Minnesota Public Utilities Commission assigns abnormal Categories I, II, and III, as shown in Section 4.2.B. The process of assigning performance categories considers Area EPS needs; as well as TPS and BPS needs on a regional and wider basis.

### A. Normal – Category A and B

Considering existing[13] and future high penetration DER conditions, and the example decision tree in Annex B of IEEE 1547, the assignment of the category for reactive power capabilities and voltage regulation performance of DER in Minnesota shall be as follows:

*Table 2. Normal Performance Category Assignment*

| Technology | Normal performance category |
|---|---|
| Inverter-based DER | Category B |
| Synchronous machine generation | Category A |

The above assignment of Categories A and B is expected to cover the vast majority of interconnections. Any instances that do not fall within the above assignment shall be:

1) reviewed on a case-by-case basis, with the Area EPS Operator making determination[14] for requiring Category A or B; or
2) performance category assignments specified in the Area EPS Operator's TSM

[12] Fault Induced Delayed Voltage Recovery is the main load consideration. This situation arises where distribution loads that typically consume reactive power draw increased levels of reactive power due to a low voltage event. The additional reactive power consumption of the distribution loads leads to a slower rebound in voltage returning to nominal levels.
[13] At the time this document is being written, portions of the Area EPS in Minnesota are exhibiting power flow characteristics of a high penetration DER environment. Based on these localized pockets of high penetration at the Area EPS level, a future with high penetration at the Area EPS, TPS, and BPS is considered when assigning performance categories in Minnesota.
[14] The Area EPS Operator should consider Annex B of IEEE 1547 when making these determinations on a case-by-case basis or in TSM requirements.

### B. Abnormal – Categories I, II, and III

The abnormal performance category assignment should also consider a future level of DER penetration that could impact the TPS or BPS if not properly coordinated. The Area EPS Operators in the state of Minnesota shall constructively work with the Regional Transmission Operator to provide a recommendation whether Category II or Category III is the proper default category assignment for inverter-based DER. The decision shall balance the needs of the Area EPS and Local EPS with TPS and BPS considerations. Until a decision is made by the Regional Transmission Operator within that region, all synchronous machine DER shall be assigned Category I and all inverter-based DER shall be assigned Category II. Any instances that do not fall within the above assignment shall:

1) be reviewed on a case-by-case basis, with the Area EPS Operator making determination[15] for requiring Category I, II or III; or
2) have performance category assignment specified in the Area EPS Operators TSM.

## 4.3 Use of Default Parameters

The DER shall use the IEEE 1547 default parameter settings for all capabilities and performance requirements of the applicable performance category unless otherwise specified by the TIIR or Area EPS Operator's TSM. In order to protect BPS and TPS reliability and to produce a response from DER that can be modeled, deviating from the statewide default parameters for abnormal performance category settings should be a rare occurrence.

## 4.4 Assignment of Alternative Abnormal Operating Performance Category

Normal Operating Performance Category assignments are shown in Section 4.2.A in this document. Abnormal Operating Performance Category assignments may be reviewed on a case-by-case basis, with the Area EPS Operator making determination for requiring Category A or B or listed in the Area EPS Operator's TSM.

Upon mutual agreement, provided no adverse effects are caused to the distribution system, TPS or BPS, exceptions may be made for Categories I, II and III if the DER technology is not able to meet the assignment outline in Section 4.2.B. This should be a rare occurrence. Should the DER technology readily exist to meet the stated assignments in Section 4.2.B, no exception shall be allowed.

# 5. Reactive Power Capability and Voltage/Power Control Performance

## 5.1 Introduction

A widely observed effect of relatively high levels of DER is reverse power flow causing an elevation of voltage near the DER source. The Area EPS Operator is responsible for maintaining voltage within standard ANSI C84.1 Range A for normal operations. Depending

[15] The Area EPS Operator should consider Annex B of IEEE 1547 when making these determinations on a case-by-case basis or in TSM requirements.

on the Area EPS characteristics for the system serving the location of interconnection, an economic solution to mitigate high-voltage caused by DER may be to implement DER active power and reactive power control functions. The implementation of these functions can contribute to an Area EPS Operator's ability to operate the system in a safe and reliable manner as increasing levels of DER are deployed. The use of these functions can allow higher levels of DER deployment in an economic manner. In general, reactive power control functions should be used to control voltage[16] for normal Area EPS conditions, by injecting or absorbing vars. The voltage-active power control function should be used for abnormal Area EPS conditions (for example temporary feeder configuration) which work by reducing active power output in order to reduce the severity or alleviate the high voltage condition.

## 5.2 General

As defined by IEEE 1547, DER reactive power capability, required by the applicable performance category[17], shall be available for use by the Area EPS Operator for the purpose of mitigating impacts of DER on the Area EPS. The real and reactive power capabilities shall be available for implementation to resolve DER grid impacts after the initial installation, even if functions are not initially implemented. The Area EPS Operator shall notify the DER Operator when a change in reactive power control modes is required to address Area EPS operating needs. Any implementation of functions shall adhere to applicable agreements.

The decision to use reactive power control functions can affect transmission power system reactive power flow patterns. TPS and BPS impacts should be considered by the Area EPS Operator when specifying reactive power control strategies in the Area EPS Operator's TSM.

The Area EPS Operator shall specify the control mode and settings for the DER. The DER Operator shall implement the settings in a reasonable timeframe. When a communication channel exists from the Area EPS Operator's communication interface to the Local DER Communication Interface, the Area EPS Operator shall have the right to adjust the settings remotely in conformance with the Interconnection Agreement. If no communication channel exists, the DER Operator shall update settings and implement the changes within the time frame required by the Area EPS Operator once receiving the change request per the Area EPS Operator's established protocol defined in agreements or within the protocol defined in the Area EPS Operator's TSM. The timeframe required for the DER Operator to update settings and implement changes should not be shorter than three (3) Business Days. The type of settings change and the impact to the operation of the Area EPS should be considered in determining appropriate time for implementing settings. Failure to carry out a settings change within the applicable timeframe requested by the Area EPS Operator, may result in temporary disconnection of the DER if the inability to make the adjustment may affect safety, reliability or service quality. Nothing in this section precludes the Area EPS

[16] The effectiveness of using reactive power control functions depends on the technical characteristics of the system including the send-out voltage, total line impedance, and X/R ratio.

[17] Categories A and B have different reactive power capability requirements, both require a percentage of the apparent power nameplate rating to be available for reactive power. Category B is capable of injecting or absorbing 44% of apparent power rating when active power output exceeds 20% of DER nameplate rating. Category A is capable of reactive power injection of 44% and absorption of 25% of nameplate apparent power when active power output exceeds 20% of DER nameplate rating. Both categories' reactive power requirements contain a gradient between 5% and 20% active power output levels. See section 5.2 of IEEE 1547 for additional details.

Operator's ability to immediately temporarily disconnect the DER for urgent operational needs at any time.

## 5.3 Voltage and Reactive Power Control

As defined by IEEE 1547 Clause 5.3.1, the Area EPS Operator specifies a reactive power control mode. Unless otherwise specified in the Area EPS Operator's TSM or specified in the Interconnection Agreement, the DER shall be installed with constant power factor mode enabled with 0.98 power factor, absorbing reactive power.

## 5.4 Voltage and Active Power Control (volt-watt)

Unless otherwise specified by the Area EPS Operator's TSM or in the Interconnection Agreement, the DER shall operate with the voltage-active power function enabled with the following default settings[18].

*Table 3. Voltage-Active Power Setting for Category A and Category B DER*

| Voltage-Active Power Parameters | Default Setting |
|---|---|
| $V_1$ | 1.06 $V_n$ |
| $P_1$ | $P_{rated}$ |
| $V_2$ | 1.1 $V_n$ |
| $P_2$ (applicable to DER that can only generate active power) | The lesser of 0.2 $P_{rated}$ or $P_{min}$[a] |
| $P'_2$ (applicable to DER that can generate and absorb active power | 0[b] |
| Open Loop Response Times | 10 s[c] |

[a] $P_{min}$ is the minimum active power output in p.u. of the DER rating.

[b] $P'_{rated}$ is the maximum amount of active power that can be absorbed by the DER. ESS operating in the negative real power half plane, through charging, shall follow this curve as long as available energy storage capacity permits this operation.

[c] Any setting for the open loop response time of less than 3 seconds shall be approved by the Area EPS Operator with due consideration of system dynamic oscillatory behavior.

The voltage-active power function may reduce DER energy production during times of abnormally high voltage. The extent of that reduction of production is dependent on the specific setting of the function, as well as actual steady-state voltage observed over time at the DER location. Deviation in the voltage parameters settings from the default, such as setting a voltage parameter to a lower value, may exacerbate the possible energy production reduction.

[18] The default IEEE 1547 volt-watt default setting will not begin curtailing real power until the voltage is beyond 1.06 per unit voltage, which is the upper end of the range of normal voltages allowed under ANSI C84.1.

In the circumstance where a DER Operator's production is being impacted by the Area EPS voltage, the DER Operator should notify the Area EPS Operator of the voltage concern[19]. The Area EPS Operator shall investigate the cause of abnormal voltage. If the abnormal voltage is originating from the Area EPS, the Area EPS Operator may need to modify equipment or settings. The Area EPS Operator may also need to work with other electric services to bring voltage within ANSI C84.1 Range A. If the abnormal voltage is originating from the DER Operator's premise, the DER Operator is responsible for mitigating the root cause.[20]

The default in IEEE 1547 is to disable voltage-active power function. The TIIR requirement may necessitate a settings change from the default settings that DER equipment may contain when shipped from a manufacturer.

# 6. Response to Abnormal Conditions

## 6.1 Introduction

Abnormal conditions can arise on the Area EPS, TPS or BPS, for which the DER shall appropriately respond based on the performance category assigned, required settings, and the requirements in IEEE 1547. The abnormal performance capabilities are intended to support wide area and localized system stability. The Minnesota statewide default parameters for DER response to abnormal conditions shall not materially impact safety, reliability, or the Area EPS Operator's ability to operate the Area EPS.[21]

## 6.2 Voltage Ride-Through and Tripping

The DER shall conform to the ride-through requirements for the applicable Abnormal Operating Performance Category. The IEEE 1547 default parameters shall be implemented by the DER Operator for the applicable performance category, unless otherwise specified by the Area EPS Operator's TSM. The RTO may provide guidance on mandatory ride-through capabilities.

Until the Regional Transmission Operator determines the setting for mandatory tripping, the Table 4 and Table 5 shall be used.

[19] For example, DER with the PCC located near the substation with a high source voltage may require upward adjustment of the $V_1$ parameter to avoid significant production impacts.
[20] All parties should attempt, with a good-faith effort, to resolve voltage concerns in the process identified in TIIR Section 5.3. Any voltage concern disputes not resolved are to follow the dispute resolution process in C-MIP Process Overview Section 11.
[21] The Area EPS Operators of Minnesota strive to be included in any efforts by the appropriate entities' Independent System Operator seeking to impose default parameter values on DER that differ from IEEE 1547. The process of determining new statewide or regional abnormal response parameter defaults that deviate from national standard default values should only be the outcome of a broad consensus process.

*Table 4. DER Response (shall trip) to Abnormal Voltages for DER of Abnormal Operating Performance Category I*

| Shall Trip – Category I | | |
|---|---|---|
| Shall Trip Function | Default Setting[a] | |
| | Clearing time (s) | Voltage (p.u. of nominal voltage) |
| UV2 | 0.16 | 0.45 |
| UV1 | 2.0 | 0.7 |
| OV1 | 2.0 | 1.10 |
| OV2 | 0.16 | 1.20 |

*Table 5. DER Response (shall trip) to Abnormal Voltages for DER of Abnormal Operating performance Category II*

| Shall Trip – Category II | | |
|---|---|---|
| Shall Trip Function | Default Setting[a] | |
| | Clearing time (s) | Voltage (p.u. of nominal voltage) |
| UV2 | 0.16 | 0.45 |
| UV1 | 10.0 | 0.70 |
| OV1 | 2.0 | 1.10 |
| OV2 | 0.16 | 1.20 |

Notes for Table 4 and 5
[a]The Area EPS Operator may specify other voltages and clearing time trip settings within the range of allowable settings, e.g. to consider Area EPS protection schemes.

### A. Modifications to the Permissive Operating Capability Region

Momentary Cessation may be required for a portion of the Permissive Operating Capability Region. Consult the Area EPS Operator's TSM for further details.

## 6.3 Frequency Ride-Through and Tripping

The DER shall conform to the ride-through requirements for the applicable Abnormal Operating Performance Category. The IEEE 1547 default parameters shall be implemented by the DER Operator for the applicable performance category. The RTO may provide guidance on mandatory ride-through capabilities.

Until the RTO provides guidance the settings for mandatory tripping, Table 6 shall be followed.

*Table 6. DER Response (shall trip) to Abnormal Frequencies for DER of Abnormal Operating Performance Category I, Category II and Category III*

| Shall Trip Function | Default Setting[a] | |
|---|---|---|
| | Clearing time (s) | Frequency (Hz) |
| UF2 | 0.16 | 56.5 |
| UF1 | 300.0 | 58.5 |
| OF1 | 300.0 | 61.2 |
| OF2 | 0.16 | 62.0 |

Notes for Table 6
[a]The frequency and clearing time set points shall be field adjustable. The actual applied under-frequency (UF) and over-frequency (OF) trip settings shall be specified by the Area EPS Operator in coordination with the requirements of the regional reliability coordinator. If the Area EPS Operator does not specify any settings, the default settings shall be used.

The DER shall conform to the Rate of Change of Frequency (ROCOF) ride-through requirements for the applicable Abnormal Operating Performance Categories. The IEEE 1547 values shown in Table 7 shall be implemented by the DER Operator for the applicable performance category.

*Table 7. Rate of Change Frequency (ROCOF) Ride-Through Requirements for DER of Abnormal Operating Performance Category I and Category II*

| **Category I** | **Category II** |
|---|---|
| 0.5 Hz/s | 2.0 Hz/s |

The DER shall conform to the frequency-droop requirements for the applicable Abnormal Operating Performance Categories. The IEEE 1547 values shown in Table 8 shall be implemented by the DER Operator for the applicable performance category.

*Table 8. Parameters of Frequency-Droop (Frequency-Power) Operation for Abnormal Operating Performance Category I and Category II*

| **Parameter** | **Default Settings[a]** | |
|---|---|---|
| | **Category I** | **Category II** |
| $k_{OF}$, $k_{UF}$ | 0.05 | 0.05 |
| $T_{response\ (small\ signal)}$ (s) | 5 | 5 |
| $db_{OF}$, $db_{UF}$ (Hz) | 0.036 | 0.036 |

Notes for Table 8
[a]Adjustments shall be permitted in coordination with the Area EPS operator.

## 6.4 Exceptions

Tripping or intentional islanding as an alternative to ride-through is allowed in specific situations (such as when a large load is on premise) which may modify the DER response to abnormal conditions. Refer to IEEE 1547 Section 6.4.2.1 and 6.5.2.1 for additional details.

DER systems designated by authority having jurisdiction as emergency, legally required, or critical operations power systems providing backup power to hospitals, fire stations or other emergency facilities as defined by applicable industry code, shall be exempt from the ride-through requirements of this section.

## 6.5 Dynamic Voltage Support

Dynamic voltage support may be required. Consult the Area EPS Operator's TSM for further details.

# 7. Protection Requirements

## 7.1 Introduction

The DER shall be designed with proper protective devices to respond to faults and abnormal conditions in accordance with applicable standards including IEEE 1547 and parameters defined by this document or the Area EPS Operator's TSM.

## 7.2 Requirements

Details of each Area EPS Operator's protection requirements shall be found in the Area EPS Operator's TSM. As specified by Area EPS Operator's TSM, an AC disconnect furnished by the DER Operator may be required for Area EPS Operator's personnel to safely isolate the DER from the Area EPS. If required, the AC disconnect shall provide a visible air-gap, shall be lockable, and accessible to Area EPS Operator's personnel to safely isolate the DER from the Area EPS.[22]

All equipment providing relay functions shall meet or exceed ANSI/IEEE Standards for protective relays, or standards applicable for the installation voltage, unless otherwise specified by the Area EPS Operator's TSM.[23] Other requirements associated with protection and instrument transformer application may be specified by the Area EPS Operator.

## 7.3 Response to Faults and Open Phase Conditions

The DER shall Cease to Energize and Trip for faults on the Area EPS. The DER shall detect and Cease to Energize and Trip all phases to which the DER is connected for an open phase condition occurring directly at the reference point of applicability. The requirement to Cease to Energize for a single-phase condition shall apply to both three-phase inverters and three-phase installations made up of single-phase inverters. As required by IEEE 1547, the DER shall detect and Cease to Energize and Trip for unintentional islands. When restoring output after Momentary Cessation, the Restore Output settings of the DER shall be coordinated with the Area EPS reclosing timing.

## 7.4 Additional Protection

Additional protection may be required as part of the Area EPS's Interconnection Facilities to limit Area EPS exposure to reliability impacts.[24] Other circumstances, such as low voltage secondary network interconnections, may require additional protection associated with the Area EPS's Interconnection Facilities.

In general, an increased degree of protection is required for increased DER size. Medium and large DER installations may require more sensitive and faster protection to minimize

[22] In some cases, the NEC required device for rapid shutdown for inverter-based DER may meet the Area EPS Operator's requirement for an AC disconnect if it provides a visual air-gap.

[23] Inverters certified to UL 1741 may contain protective functions that do not require equivalent external protective relays to meet IEEE 1547 requirements.

[24] For example, additional layers of protection may be required if the Area EPS's Interconnection Facilities lead to significant line exposure.

potential damage and ensure safety.[25] The addition of a new DER in conjunction with the aggregate of the existing DER systems may also affect the ability of existing protection schemes to function, which may require modification to the Area EPS's protection equipment.

# 8. Metering

## 8.1 Introduction

The Area EPS Operator shall specify metering requirements in the Area EPS Operator's TSM. Information about the DER's present and historic operating characteristics may be required by the Area EPS Operator in order to plan and operate the system. In addition, information may be needed to fulfill financial and regulatory obligations associated with DER energy production.

The different types of data may have different requirements in terms of accuracy and granularity, which should be considered by the Area EPS Operator. The information required for a given DER size may change as DER penetration increases on a portion of the Area EPS. Furthermore, each utility uses different metering technology that changes over time, each with its own integration considerations. Defining static metering requirements is a challenge. It is beyond the scope of this document to describe all of the potential different metering configurations or requirements. In general, the Area EPS Operator shall consider the following types of information when developing metering requirements in its TSM:

i. Operational – near-real-time information on the DER operating characteristics can be needed in order to perform certain actions such as reconfiguring a feeder or restoring a feeder after an outage.
ii. Planning – an archive of time-series information over multiple years of DER operation is required for Area EPS, BPS and TPS planning.
iii. Regulatory – The Area EPS Operator may have obligations to track and report on the amount of energy produced from renewable energy DER[26]. Specific incentive programs or tariffs can create additional metering needs.
iv. Billing – the Area EPS Operator is responsible for accounting for energy transactions with the DER Operator and shall have access to revenue grade metering information.

The Area EPS Operator may require separate accounting of generation and load power injection and consumption characteristics in order to meet planning and operating objectives on the Area EPS and TPS. Correlation of time data may be necessary in certain situations[27] and the Area EPS Operator should consider this factor when specifying metering requirements in its TSM. The Area EPS Operator may use other means of collecting the necessary information, besides the meter, if the Area EPS Operator determines the information is adequate for the intended use based on industry standards and best practices.

[25] Ride-through capabilities for bulk power system support should be considered before setting protective tripping times that conflict with BPS support.
[26] Renewable energy credits for certain Area EPS Operator tariffs is an example of reasons to track energy production.
[27] For example, where a time of use tariff exists and multiple meters are present, the time intervals of meters need to be time synchronized in order for the Area EPS Operator to properly execute its tariffed obligations. Another example would be a planning need where data has to be synchronized in time.

## 8.2 Requirements

The DER installation shall include metering provisions based on the interconnection characteristics and requirements. Each Area EPS Operator shall specify requirements in their TSM.

# 9. Interoperability

## 9.1 Introduction

The IEEE 1547 standard requires the capability to provide a Local DER Communication Interface, which is the basis for interoperability requirements. The Local DER Communication Interface may be used to exchange standardized information with the Area EPS Operator. The exchange of information allows the Area EPS Operator to perform monitoring and control functions necessary to the safe and reliable operation of the Area EPS.

Per IEEE 1547 Section 10.1, the decision to use the Local DER Communication Interface or to deploy a communications network is determined by the Area EPS Operator. Given existing and future DER integration needs, as well as the differences amongst various Area EPS Operator's systems, no uniform set of standards is defined in this document for requiring use of the Local DER Communication Interface. The factors included in an Area EPS Operator's decision to use the Local DER Communication Interface shall be provided in the Area EPS Operator's TSM.

For DER where a standard Local DER Communication Interface is not used upon initial installation, future Area EPS, TPS, or BPS conditions may arise that trigger a need to begin using the Local DER Communication Interface. The DER Operator shall constructively participate in evaluating feasibility of establishing use of the Local DER Communication Interface if needed due to considerations for integrating DER with an Area EPS. Any modifications to utilize the Local DER Communication Interface for existing interconnected DER systems shall be established by mutual agreement between the Area EPS Operator and the DER Operator.

DER systems designated by authority having jurisdiction as emergency, legally required, or critical operations power systems providing backup power to hospitals, fire stations or other emergency facilities as defined by applicable industry code, may be exempt from the interoperability requirements of this section. Additional details are listed in the Area EPS Operator TSM.[28]

## 9.2 Monitoring, Control and Information Exchange

When information exchange through the Local DER Communication Interface is required by the Area EPS Operator, the IEEE 1547 interoperability parameters shall be available for use. The Area EPS Operator shall have read access to all parameters in the nameplate information and monitoring information. The Area EPS Operator shall have read and write access to all parameters in configuration information and management information. The Area EPS

[28] IEEE 1547 does allow exemption in capabilities that the Area EPS operator may require in certain situation.

Operator may choose to use a subset of the available parameters in order to meet operating objectives of safe, reliable, and quality electric service. Writing of information by the Area EPS Operator through the Local DER Communication Interface, shall follow agreements governing Area EPS Operator control of the DER operating state control modes and parameters.

When the Local DER Communication Interface is required by the Area EPS, the Area EPS shall have access to read and write parameters shown in the sub clauses associated with IEEE 1547, Section 4.6 – *Control capability requirements* – including capability to disable permit to service; capability to limit active power; and execution of mode and parameter changes.

## 9.3 Communications

When communication is required to the DER and/or the applicable meter(s), the DER Operator may be responsible for furnishing the communication channel from the Area EPS Operator's applicable system(s) to the DER and/or the meters. The form of communication (Cellular, Radio, etc.) shall be determined by the Area EPS Operator. Additional details of communication requirements shall be specified in the Area EPS Operator's TSM. Communication performance requirements, such as latency of exchanged information, periodicity, reliability of communication channels, and volumes of data, may be defined by the Area EPS Operator's TSM or in an operating agreement.

## 9.4 Cyber Security

The local physical and network security requirements specified by the Area EPS Operator shall be implemented by the DER Operator. The Area EPS should consider the degree of risk associated with various DER technology and application in determining the cyber security requirements. The Area EPS Operator shall outline cyber security requirement with respect to DER in its TSM.

Communications circuits tied to monitoring and control systems associated with Area Electric Power System (EPS) real-time operations shall meet security and reliability requirements as defined by the Area EPS Operator, industry standards, and appropriate regulating authorities.

### A. DER Physical and Front Panel Security

The DER Operator shall provide a reasonable level of security for the DER controls and devices from operation by intruders. The Area EPS Operator may specify additional physical security requirements in its TSM.

### B. DER Network Security

The network security requirements and implementation details may differ among Area EPS Operators and are expected to evolve over time in order to maintain cyber security in an environment of constantly changing cyber threats. The network security requirements for the DER Operator may be described in each Area EPS Operator's TSM.

### C. Local DER Communication Interface Security

When information is exchanged through the Local DER Communication Interface, consideration should be given to protect access to information. Numerous system architecture approaches and technologies exist for securing the interface. The Area EPS Operator may specify security requirements associated with the Local DER Communication Interface. Where practical, test and verification procedures shall be specified for local DER communication interface security.

# 10. Energy Storage

## 10.1 Introduction

An Energy Storage System (ESS) operated in parallel with the Area EPS is a DER subject to the standard applicable reviews and requirements for a DER acting as a generation source (ESS discharging). Additional review is required for unique features of ESS, when compared to other DER, such as the load (ESS charging) aspects and ESS Control Mode(s). The Area EPS Operator should perform the appropriate technical review and study of all aspects of ESS during the appropriate step in the Cooperative Minnesota Interconnection Process. Power Control characteristics may simplify the review process, since ESS is often inverter-based and ongoing reverse power flow may not be anticipated, but a standard review shall be completed since the potential exists for voltage, thermal, and protection impacts.

Interconnection of ESS in a parallel configuration often requires consideration of compatibility with applicable tariffs. ESS interconnection or operational requirements may result from a customer's choice of DER tariff[29] or load service tariff.

Application of the Cooperative Minnesota DER TIIR shall not constrain adoption of national standards and best practices as they are developed. The ESS-specific aspects of DER interconnection standards are expected to receive an increased focus from industry standards associations in upcoming years[30], with resulting ESS standards publications at a quicker pace.

The absence of guidance on ESS best practices and standards at a national level makes it likely that this section will require future revision sooner than other sections in the document. The intent of this document is to adopt standards as they become available. The approach taken for ESS in the TIIR is to define functional requirements, leaving implementation, testing, and verification for definition in individual Area EPS Operator's TSM. As was the case with inverter-based DER prior to IEEE 1547 in 2003, the types and use cases associated with ESS will continue to rapidly shift until standards and certifications are developed. Based on these factors, the Area EPS Operator shall specify any additional ESS requirements in the Area EPS Operator's TSM.

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[29] For example, a tariff rate associated with a Qualifying Facility (QF), as defined in federal law and often relied upon in net metering rate definitions of eligible energy resources, requires all energy exported to the Area EPS to be from a QF. For ESS to be considered a QF, all of the energy charging ESS must originate from a different DER which meets the QF definition.

[30] At the time the TIIR are being written, certifications, national standards, guides, and recommended practices governing the capabilities and performance of ESS are yet to be written or published.

### 10.2 ESS Control Modes

Changes in ESS Control Modes to a mode that was not proposed and reviewed during the interconnection process can result in tariff violations or cause adverse technical impacts to the Area EPS. ESS Control Modes may not necessarily be considered a Material Modification, however the Interconnection Customer shall notify the Area EPS Operator of an unapproved ESS Control Mode prior to the change being implemented. The Area EPS Operator shall discuss with the Interconnection Customer the need, or lack thereof, to review the proposed ESS Control Mode for safety, power quality or reliability reasons.

IEEE 1547 states that a functional software or firmware change may result in another verification process at that time of interconnection and interoperability requirements. The IEEE 1547 standard, and other national standards and certifications, are currently silent on requirements relating to ESS Control Mode definition, implementation (i.e. default responses and ranges of allowable settings), transition between modes, adding new modes after initial interconnection, and all associated testing and verification procedures. Until industry standards and certifications are developed to address these aspects of ESS, a significant gap exists for which a grouping of partial solutions may be required by the Area EPS Operator, including, but not limited to the following requirements:

i. Documenting at the time of application the ESS Control Modes being applied for by the ESS owner. This information may be collected through an Area EPS Operator specific document[31] or the Area EPS Operator's online application portal.
ii. Documenting at the time of application the charge/discharge profile(s) or use case(s) intended to be utilized by the ESS owner. This information may be collected through an Area EPS Operator specific document or the Area EPS Operator's online application portal.
iii. The ESS Control Mode(s) reviewed and approved should be documented in an Operating Agreement. The Operating Agreement should also list the ESS Control Mode(s) that is being utilized. Area EPS Operator shall be notified of changes to ESS Control Mode(s). The changes and notification to the Area EPS Operator shall follow all applicable agreements and requirements as documented in the TSM.
iv. A method of ESS Control Modes security shall be furnished by the DER Operator to assure only ESS Control Modes applied for and reviewed by the Area EPS Operator are used. The security may be in the form of password protection of the functions or other methods specified by the Area EPS Operator's TSM.
v. Operation of the ESS shall be compatible with applicable tariffs[32], as required by the Area EPS Operator standard implementation of the tariffs.
vi. The Area EPS Operator may initiate verification of the ESS operation after the interconnection is complete if information is available indicating the ESS is not functioning as designed or approved.

[31] Upon publication of standards and certifications, this type of information will be well-suited to be included in statewide interconnection process documentation. Until that time, it is likely the type of ESS information needed could rapidly shift, depending on customer preferences and available technology. Continual shifts in technology, application of technology, and market place are occurring at a rapid pace at the time the TIIR is being written.

[32] Definitions of non-exporting and inadvertent export in statewide standards clarifies implementation of certain tariffs for ESS.

### 10.3 ESS Load Aspects

The load impacts of ESS shall be considered in scope for the statewide TIIR. The load aspects of ESS are not in scope of the IEEE 1547 standard, but reviewing the load aspects in conjunction with generation aspects is crucial to evaluating impacts to the Area EPS and leads to a more efficient review of the overall system. Impacts from ESS may contribute to requirements and mitigations, including but not limited to: electrical component upgrades; information exchange through use of the Local DER Communication Interface; or protection and control system upgrades.

Any Area EPS Operator's operating characteristics requirements for ESS charging operations shall not be more restrictive than the operating characteristics requirements of other comparable loads, to the extent practical or upon mutual agreement. The maximum charge rate of the ESS shall be included in materials submitted to the Area EPS Operator during the technical review portion of the interconnection process.

Certain grid events[33] may cause a large number of ESS in the affected area to simultaneous respond. Any future changes to wholesale markets allowing ESS to participate could also introduce unintentional wide-area ESS simultaneous response and impacts not accounted for during the interconnection process. Interconnection reviews typically do not contemplate this type of group response. The Area EPS Operator may define in the TSM interconnection technical requirements to address impacts from conditions where multiple unrelated ESS on a portion of the Area EPS are operating in concert.

## 11. Power Control Limiting – Capacity, Export, and Import

### 11.1 Introduction

The DER Operator may choose to limit the AC capacity of a DER system using Power Controls. Power Controls may also be used to limit DER system export levels to the Local EPS and/or the Area EPS. There are many possible reasons for implementing Power Controls, including meeting specific tariff terms or to mitigate the maximum level of power which can flow on the Local or Area EPS.

These capabilities are referred to as Power Control limited capacity, Power Control limited export, and Power Control limited import. These terms are discussed in the following sections and may be generally referred to as Power Control limiting. Power Control limiting may be accomplished using a Power Control limiting system. An alternate option, specifically related to assurance that the DER does not export power (non-export) to the Area EPS, is to implement the limit through relaying or by sizing DER in relationship to the size of the Local EPS load. The use and method for Power Control limiting shall require approval from the Area EPS Operator[34].

[33] For example, an extended outage could cause all the impacted ESS charge to largely deplete, which could trigger charging of all the effected ESS when power is restored on the Area EPS. The resulting charging could result in unanticipated overloads on the Area EPS unless the condition has been studied.

[34] C-MIP Process Overview Section 6.3 explains *limited capacity* and discusses the requirements of Area EPS Operator approval for this situation.

### 11.2 Power Control Limited Capacity

Using Area EPS Operator's approved Power Control methods, the DER Operator may limit the DER AC capacity. The limited DER AC capacity value may be used by the Area EPS Operator when performing impact studies if the means of limiting capacity is determined to be adequate by mutual agreement. Some of the reasons the DER Operator may choose to limit DER AC capacity include, to avoid system upgrades or to size the DER to be compatible with programs or tariffs[35].

For inverter-based DER systems 20 kW or less in Nameplate Rating, the Power Control limited capacity shall be implemented through utilizing the IEEE 1547 configuration settings[36]. For Power Control capacity limiting, active power limits at unity and non-unity power factors may be applied. The DER Operator shall propose the configuration settings to the Area EPS Operator for review and approval.

For rotating machines or inverter-based DER systems larger than 20 kW in Nameplate Rating, the DER Operator shall submit details of the proposed Power Control limiting method for maximum capacity limiting, along with settings, if applicable. The Area EPS Operator shall review and either approve the proposed Power Control method and settings or provide a response as to why the method does not provide adequate control. The DER system should use the IEEE 1547 configuration settings as the preferred means of Power Control limited capacity.

### 11.3 Power Control Limited Export and Power Control Limited Import

Power Control limited export and Power Control limited import can provide means of meeting the requirements of specific Area EPS Operator's tariffs or other technical requirements. The DER Operator shall obtain approval from the Area EPS Operator for any Power Control limiting system which is implemented. Power Control limiting for inverter-based DER systems with a Nameplate Rating of 20kW or less shall use a certified control system tested to UL 1741[37]. For these smaller systems, the DER Owner shall submit proposed settings to the Area EPS Operator for review and approval. For DER systems with a Nameplate Rating larger than 20 kW using a certified control system tested to UL 1741, the DER Operator shall provide test results showing the magnitude and duration of power import or export.

The Power Control limited export and import may be applied using a UL 1741 certified Power Control System to limit import or export. Additionally, Power Control limited export may be applied using the IEEE 1547 *maximum active power* parameter to limit export in the

[35] The applicable programs or tariffs eligibility may be based on a nameplate capacity rather than a configured value. Consult the tariff or program rules of interest to determine if the nameplate capacity governs any aspects of the interconnection.

[36] IEEE 1547 Table 28 Nameplate Information contains the available configuration parameters which may be altered as allowed by Section 10.4.

[37] Testing to the UL Certification Requirement Decision on Power Control Systems may be used in the interim.

management settings[38] in cases where the RPA is at the PCC. The *maximum active power* parameter in the DER management information shall be used as a static limit when employed for limiting export. Similarly, the Power Control System import or export limit shall be a static limit when employed for limiting export or limiting import.

The current approved standards-based approaches for Power Control limiting have a maximum open loop response time limit of 30 seconds for limiting inadvertent active power exchange with the Area EPS. Active power exchange may occur for a period of time within this 30 second limit due to Local EPS conditions such as block load changes. Reactive power exchange between the DER, Local EPS and the Area EPS may occur during normal operations, but level and amount of this exchange shall be in accordance with applicable agreements.

The configuration and settings governing the Power Control limiting functions shall be password protected, accessible only by qualified personnel, or protected by other means which have been approved by the Area EPS Operator.

### 11.4 Other Power Control Methods

While this technical document has attempted to provide guidance and standards for Power Control limiting methods, this is a new and quickly changing area. This technical standard shall not preclude alternate means of Power Control limiting which may be implemented by mutual agreement between the DER Operator and the Area EPS Operator. The DER Operator shall provide details to the Area EPS Operator for any proposed Power Control limiting function. The proposal shall include settings, equipment information, and any other information necessary for the Area EPS Operator to complete a review of the proposal. Non-export limitations based on relaying or load characteristics are examples of potential proposals from a DER Operator. It is recommended that the DER Operator consider using a standards-based Power Control limiting system prior to proposing alternate solutions.

## 12. Enter Service and Synchronization

When entering service, the DER shall not energize the Area EPS until voltage and system frequency are within the ranges specified in Table 9 or established by Area EPS Operator's TSM.

*Table 9 Enter Service Voltage and Frequency Criteria*

| **Enter Service Criteria** | | **Default Settings** |
|---|---|---|
| Applicable voltage within range | Minimum value | $\geq$ 0.917 p.u. |
| | Maximum value | $\leq$ 1.05 p.u. |
| Frequency within range | Minimum value | $\geq$ 59.5 Hz |
| | Maximum value | $\leq$ 60.1 Hz |

[38] IEEE 1547 Section 4.6.2 allows for an active power limit to be set as an export limit when the RPA is the PCC. The parameter is found in Table 40 of IEEE 1547 Section 10.6.12.

The DER shall parallel and synchronize with the Area EPS in accordance to IEEE 1547.

# 13. Intentional Islanding

As an alternative to cease to energize and trip in response to voltage or frequency disturbances or unintentional island detection, a Local EPS island may be formed. When DER meets the criteria of Section 6.4, a Local EPS island may be formed rather than ride-through for voltage or frequency disturbances. If DER does not meet the criteria of section 6.4, the transition to the Local EPS island shall meet the rapid voltage change requirements of IEEE 1547. When paralleling a Local EPS island to the Area EPS, the Enter Service and Synchronization requirements of Section 12 shall be met.

DER systems designated by authority having jurisdiction as emergency, legally required, or critical operations power systems providing backup power to hospitals, fire stations or other emergency facilities as defined by applicable industry code, shall be exempt from this section and may Cease to Energize and Trip or separate from the Area EPS without limitation. Scheduled intentional Local EPS islands are allowed in accordance with IEEE 1547 Section 8.2.2 and applicable agreements.

Intentional Area EPS islands shall only be allowed upon mutual agreement between the Area EPS Operator and DER Operator.

# 14. Test and Verification Requirements

## 14.1 Introduction

Prior to a DER system's initial interconnection or operation in parallel with the Area EPS, the Area EPS Operator may require verification and testing of the DER interconnection. The Area EPS Operator's TSM document is expected to be reviewed to understand the interconnection testing requirements. The testing of the DER shall depend upon the type, size and complexity of the DER system. For DER systems utilizing certified inverters, which meet the IEEE 1547 interconnection requirements, the testing shall be to confirm the proper installation and configuration of the equipment.

Type tests and conformance testing are related to the interconnection requirements and safety aspects. The operational compliance with applicable tariffs, which is often pertinent for storage, is not affirmed through the test and verification requirements outlined in this section.

The process associated with design, approval and execution of test and verification procedures follows:

- The Area EPS Operator shall define the characteristics of tests that are required by applying standards and best practices.
- The RPA shall be specified in the one-line diagram submitted to the Area EPS Operator with the Interconnection Application. The DER Operator shall denote the RPA where

the test and verification feature shall be applied in the written test procedure, if required.

- When required by the Area EPS Operator, the DER Operator shall provide written test procedure to the Area EPS Operator for review.
- The testing and verification procedures shall be reviewed and approved by a Professional Engineer when a Professional Engineer is required for design of the DER as specified by the C-MIP[39].
- The Area EPS Operator shall provide written feedback to the DER Operator, if written test procedures are required, indicating the determination if the test and verification meets applicable requirements. Prior to witness testing, the Area EPS Operator may require the DER Operator to attest the DER system is ready for testing.[40]
- The Area EPS Operator and the DER Operator shall arrange for qualified personnel to perform the test procedures. Each entity shall operate their own equipment.
- The Area EPS Operator may arrange personnel to witness the test procedures being performed by the DER Operator.
- The Area EPS Operator may evaluate the DER as-built installation, including as outlined in IEEE 1547.1, during this site visit to verify that the installation meets interconnection and interoperability requirements.

The applicable DER evaluation, commissioning tests and verifications, shall be performed per IEEE 1547, IEEE 1547.1, and Area EPS Operator's TSM.

### 14.2 Full and Partial Conformance Testing and Verification

All DER used for interconnection with an Area EPS shall be tested to conform to IEEE 1547 interconnection requirements using IEEE 1547.1 conformance test procedures. Additional testing to affirm compliance with applicable tariffs may be outlined by the Area EPS Operator within their TSM. One way a DER shall be considered as conforming to IEEE 1547 is if it has been submitted by a manufacturer, tested and listed by an Occupational Safety and Health Administration (OSHA) Nationally Recognized Testing Laboratory (NRTL) for continuous grid interactive operation in compliance with the applicable codes and standards and is determined to be fully compliant. DER equipment shall be tested to conform to the IEEE 1547 requirements and listed in accordance with an OSHA NRTL.

All inverter-based DER units shall be UL 1741 certified. Certified DER equipment that do not require a supplemental DER device to meet IEEE 1547 requirements at the Reference Point of Applicability and where the impedance between the PCC and POC is less than 0.5% on the DER rated apparent power and voltage base shall be considered fully compliant. Partially compliant DER shall require further evaluation and possible testing. All DER systems shall meet the requirements of IEEE 1547 regardless of whether they are classified as fully or partially compliant.

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[39] A Minnesota license Professional Engineer signature is required for certified system greater than 250 kW or for non-certified system greater than 20 kW as outlined in C-MIP Fast Track Process Section 2.2.

[40] C-MIP Certificate of Completion is an example of certifying the DER system is ready for testing.

IEEE 1547 introduces the concepts of Reference Point of Applicability, which is located at either the PoC or the PCC. The IEEE 1547 standard section 4.2 should be referenced to determine the RPA, as the RPA is the point at which testing and verification requirements apply. Annex B in this document describes the relationship of these terms.

Figure 3 details the test and verification required steps when the RPA is at the PoC for a fully compliant DER Unit or DER system as well as a partially compliant composite DER system. Fully compliant DER Unit(s) require *basic* design evaluation and commissioning tests. Partially compliant DER Units(s) require *detailed* design evaluation. For example, a fully compliant DER Unit(s) with the RPA at the PoC is representative of a residential rooftop PV system. The DER Unit would be type tested by a NRTL resulting in a UL 1741 certification. IEEE 1547.1 details the Design Evaluation and Commissioning Test required for each of the combinations of fully and partially compliant DER with the RPA at the PoC and PCC.

*Figure 3 Test and Verification Required Steps for RPA at PoC*

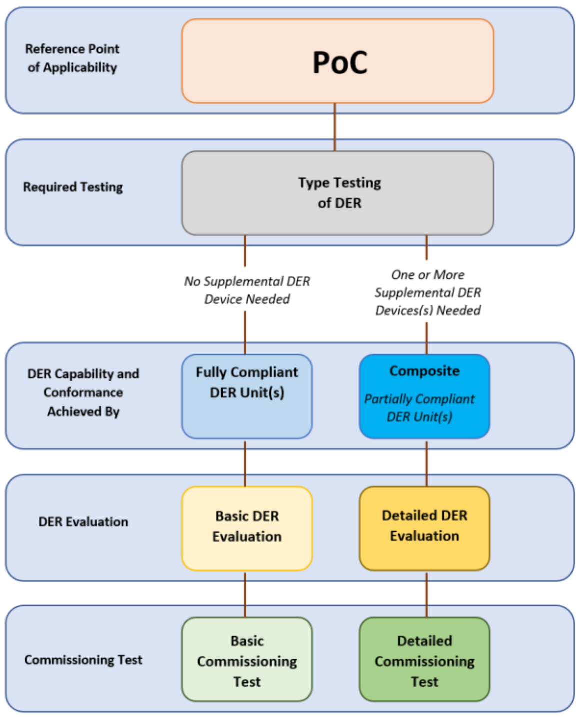
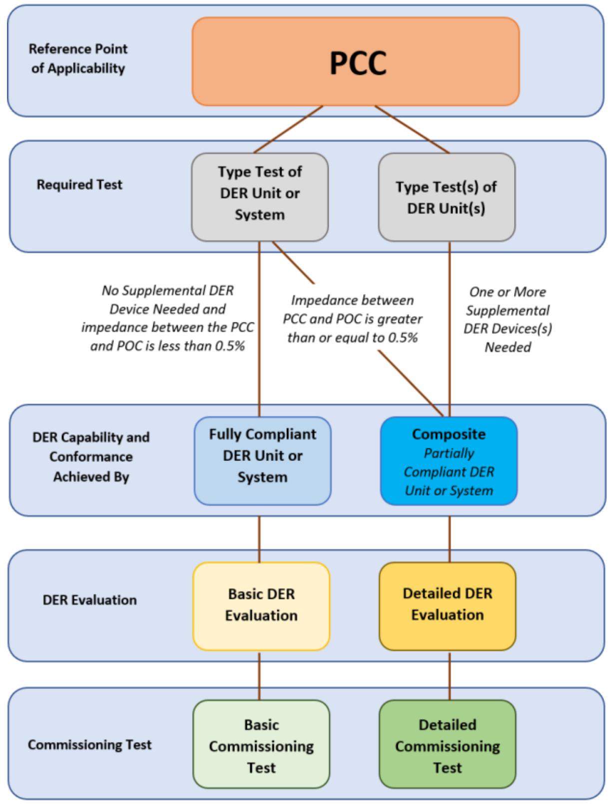



Figure 4 details test and verification requirements when the RPA is at the PCC. Requirements for fully compliant DER Units or systems and partially compliant DER Unit or systems are addressed separately in terms of required testing and evaluation.

*Figure 4 Test and Verification Required Steps for RPA at PCC*




## 14.3 Documentation

Testing and verification documentation requirements shall be specified in the Area EPS Operator's TSM. Fault current characterization information required in IEEE 1547, subclause 11.4, shall be provided to the Area EPS Operator upon request or per the Area EPS Operator's TSM.

## 14.4 Failure Protocol

In the event that a DER fails testing and verification, the DER Operator shall resolve any out-of-compliance items and resubmit or reschedule the appropriate items as defined by the C-MIP and Area EPS Operator's TSM.

## 14.5 Reverification and Periodic Tests

The DER Operator shall notify the Area EPS Operator prior to any of the following events occurring:

- Protection functions are being adjusted after the initial commissioning process.
- Functional software or firmware changes are being made on the DER.
- Any hardware component of the DER is being modified in the field or is being replaced or repaired with parts that are not substitutive components compliant with this standard.
- Protection settings are being changed after factory testing.

Prior to modifications to the DER triggering reverification, the DER Operator shall notify the Area EPS Operator's interconnection coordinator, as identified on the Area EPS Operator's website. Any of the above events may be cause for requiring reverification of the interconnection and interoperability requirements, per IEEE 1547 clause 11.2.6.

The Area EPS Operator may specify the frequency or time intervals for periodic testing consistent with Area EPS Operator's policies or manufacturer requirements.

### 14.6 Simplified Process Testing Procedure

The general process for field inspection and testing of an inverter-based DER that is less than 20 kW in size and approved through the Simplified Process, is outlined below. Specifics of the testing procedure and the responsibilities of the installer shall be identified in the Area EPS Operator's TSM.

General Process for Simplified Testing Procedures

- Verify installation matches design evaluation
  - Verify inverter model matches application
  - Verify certified inverter
  - Verify correct labeling / signage
  - Verify installation matches application one-line (i.e. connections, location of protection, disconnect switch, metering etc.)
  - Verify electrical inspection sticker
  - Verification of operational and protection settings

- Field Testing
  - On-off test
  - Open phase testing (if applicable for multiphase systems)

## 15. Operating and Maintenance Requirements

Operating and Maintenance Requirements may be required by the Area EPS Operator and are documented in Attachment V of the Interconnection Agreement.[41] The Operating and Maintenance Requirements are created for the benefit of both the DER Operator and the Area EPS Operator and shall be agreed to between the parties.

Operating and Maintenance Requirements may be reviewed and updated periodically to allow the operation of the DER to change to meet the needs of the DER Operator and the Area EPS Operator. There may also be changes required by external issues, such as changes in FERC and RTO recommendations or policies, which may require the updates to the Operating and Maintenance Requirements. Any updates to the Operating and Maintenance Requirements shall be agreed to between parties. In cases where mutual agreement cannot be achieved, see C-MIP Process Overview Section 11 and C-MIP Interconnection Agreement Section 25.

The following is a list of typical items that may be included as Operating Requirements. The items included as Operating Requirements shall not be limited to the items shown on this list:

[41] The Interconnection Agreement requirements are defined in the C-MIP Interconnection Agreement.

i. Operational requirements, settings, and limits for DER when the Area EPS is in a normal condition
ii. Operational requirements, settings, and limits when the Area EPS is in an abnormal condition due to maintenance, contingencies, or other system issues
iii. Permitted and disallowed ESS Control Modes
iv. BPS or TPS limitations and arrangements that could impact DER operation
v. DER restoration of output or return to service settings and limitations
vi. Response to control or communication failures
vii. Performance category assignments (normal and abnormal)
viii. Dispatch characteristics of DER
ix. Notification process between DER Operator and Area EPS Operator
x. Right of Access

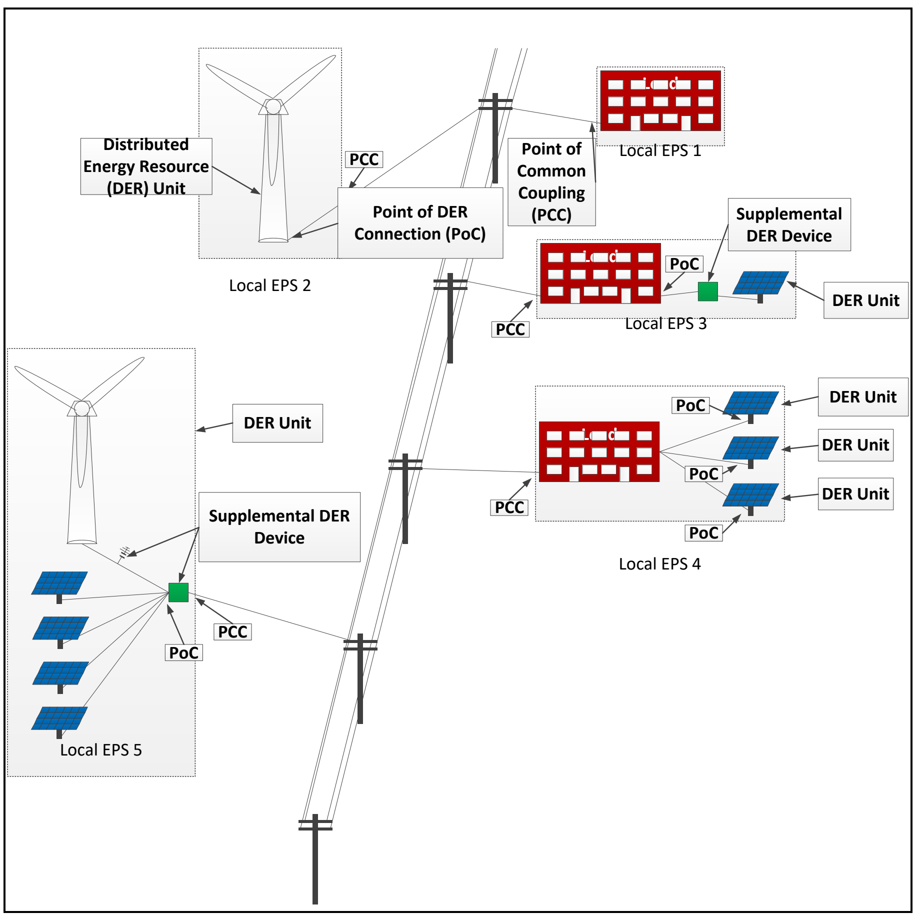
The following is a list of typical items that may be included as Maintenance Requirements. The items included as Maintenance Requirements shall not be limited to the items included in this list:

i. Routine maintenance requirements and definition of responsibilities
ii. Material modification of the DER that may impact the Area EPS

# Annex A – Clarification on Reference Point of Applicability, Point of Common Coupling, Point of DER Connection, and Supplemental DER Devices

The reference point of applicability (RPA) is the location where the requirements in IEEE 1547 and IEEE 1547.1 apply. The TIIR adopts the RPA as the location to apply technical requirements. The RPA is usually at the PCC or PoC. A location between the PoC and PCC can be mutually agreed upon as a substitute for when the location is determined to be at the PoC. The influence of load on the overall Local EPS operating characteristics is a driver behind the need for the RPA to be at the DER PoC. For example, meeting the reactive power requirement for DER may not be feasible if the DER is relatively small compared to a reactive power load in the same Local EPS. Similarly, ground referencing of the Local EPS also affects the ability of a DER to meet certain protection requirements. For example, detection of a loss-of-phase is not possible without zero-sequence continuity[42] between the Area EPS and Local EPS.

Decision trees for determining RPA are described in IEEE 1547, Section 4.2.




[42] For example, a transformer delta winding breaks zero-sequence continuity.

# Annex B –TSM Outline

| | |
|---|---|
| 1 | Introduction |
| 2 | Abbreviations and Common Terms |
| 3 | Performance Category Assignment |
| 4 | Reactive Power Capability and Voltage/Power Control Performance |
| 5 | Response to Abnormal Conditions |
| 6 | Protection Requirements |
| 7 | Operations |
| 8 | Power Control Systems |
| 9 | Interoperability |
| 10 | Energy Storage Systems |
| 11 | Metering Requirements |
| 12 | Signage and Labeling |
| 13 | Test and Verification Requirements |
| 14 | Sample Documents for Simplified Process |
| 15 | Appendix |

# Annex C– Interim Implementation Guidance

The following clarifies which sections of the TIIR go into effect immediately and which are replaced with an existing technical requirement until the Commission provides Notice that IEEE 1547-2018 certified equipment is readily available ("Commission Notice".)[43] The "interim period" referred to below is from July 1, 2020, the date the TIIR goes into interim effect, until the Commission Notice announcing the TIIR is in full effect.

All sections of the TIIR shall go into effect on July 1, 2020 except for the following sections for inverter-based systems. Mutual agreement between parties does allow for utilization of the full TIIR during the interim period.

**Section 4 (Performance Categories)**
This section does not go into effect until Commission Notice. No alternate provision is in place during the interim period.

**Section 5 (Reactive Power Capability and Voltage/Power Control Performance)**
Sections 5.4 does not go into effect until Commission Notice unless mutual agreement exists between parties. In the interim period, the power factor requirements of Section 5.3 shall be used as default settings[44].

**Section 6 (Response to Abnormal Conditions)**
This section does not go into effect until Commission Notice. In the interim period, the following tables shall be considered default settings unless mutual agreement between parties exists.

*Table C1 - Synchronous DER Response (shall trip) to Abnormal Voltages*

| **Shall Trip – Synchronous DER** | | |
|---|---|---|
| **Shall Trip Function** | **Default Setting** | |
| | **Clearing time (s)** | **Voltage (p.u. of nominal voltage)** |
| UV2 | 0.16 | 0.50 |
| UV1 | 2.0 | 0.88 |
| OV1 | 1.0 | 1.10 |
| OV2 | 0.16 | 1.20 |

[43] MN PUC, ORDER 159427-01, Docket E-999/CI-16-521. Request input from the Technical Subgroup (TSG) of the Distributed Generation Workgroup (DGWG) as to when IEEE 1547-2018 certified equipment is "readily available" and delegate to the Executive Secretary the authority to notice when the full TIIR goes into effect in consultation with the TSG. Minnesota electric cooperatives are encouraged to implement the full TIIR at this time.
[44] IEEE 1547-2018 section 5.3.1, as referenced in the TIIR, does not apply in the interim period, but the constant power factor specification requirement can be applied.

*Table C2 - Inverter DER Response (shall trip) to Abnormal Voltages*

| Shall Trip – Inverter DER | | |
|---|---|---|
| **Shall Trip Function** | **Default Setting** | |
| | **Clearing time (s)** | **Voltage (p.u. of nominal voltage)** |
| UV2 | 0.16 | 0.50 |
| UV1 | 2.0 | 0.88 |
| OV1 | 1.0 | 1.10 |
| OV2 | 0.16 | 1.20 |

*Table C3 - DER Response (shall trip) to Abnormal Frequencies*

| **Shall Trip Function** | **Default Setting** | |
|---|---|---|
| | **Clearing time (s)** | **Frequency (Hz)** |
| UF1 | 0.16 | 59.3 |
| OF1 | 0.16 | 60.5 |

**Section 9 (Interoperability)**
This section does not go into effect until Commission Notice. In the interim period, the Area EPS Operator's TSM shall be used. The Area EPS Operator's TSM shall contain Interoperability requirements comparable to section 5 (regarding metering and monitoring control requirements) of the 2004 State of Minnesota Distributed Generation Interconnection Requirements document.

**Section 12 (Enter Service and Synchronization)**
This section does not go into effect until Commission Notice. In the interim period, when entering service, the DER shall not energize the Area EPS until the applicable voltage and system frequency are within the ranges specified in Table 4, unless mutual agreement between parties exists.

*Table C4 - DER Enter Service Criteria Ranges*

| Enter Service Criteria | | Default settings |
|---|---|---|
| Applicable voltage within range | Minimum Value | ≥0.917 p.u. |
| | Maximum Value | ≤1.05 p.u. |
| Frequency within range | Minimum Value | ≥59.3 Hz |
| | Maximum value | ≤60.5 Hz |

DER shall be capable of delaying enter service by an intentional adjustable minimum delay when the Area EPS steady-state voltage and frequency are within the ranges specified in Table C4. The adjustable range of the minimum intentional delay shall be 0 s to 300 s with a default minimum delay of 300 s.

**Section 14 (Test and Verification Requirements)**
This section does not go into effect until Commission Notice. In the interim period, the Area EPS Operator's TSM shall be used. The Area EPS Operator's TSM shall contain Test and Verification requirements comparable to section 8 of the 2004 State of Minnesota Distributed Generation Interconnection Requirements document.