MINNESOTA POWER

TECHNICAL SPECIFICATIONS MANUAL (TSM)

Minnesota Power's Technical Specifications Manual (TSM) has been developed to accompany the Minnesota Technical Interconnection and Interoperability Requirements (TIIR). The specifications and guidelines contained in this manual are applicable to all Distributed Energy Resources (DERs) that want to connect to the Minnesota Power electric distribution system. While the TSM and TIIR draw heavily from the existing IEEE 1547 standard, customers and installers should be familiar with the information contained within Minnesota Power's TSM to ensure compliance when applying for interconnection.

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1 Introduction

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This version of the TSM has been updated to reflect changes to the TIIR that were approved by the Minnesota Public Utilities Commission in its April 11, 2023, Order Conditionally Adopting Amended Technical Interconnection and Interoperability Requirements and Requiring Filings. The Commission determined that the 2023 revised version of the TIIR would be effective upon the date set in a future notice by the Commission that IEEE 1547-2018 advanced inverters are "readily available."

This document covers technical aspects of DER interconnection only. For information concerning the application and approval processes, please refer to the State of Minnesota's *Distributed Energy Resources Interconnection Process* (MN DIP). Please refer to the Minnesota Power website for solar (https://www.mnpower.com/Environment/CustomerSolar) for more helpful documents and guidance for interconnecting to the Minnesota Power system.

2 Abbreviations and Common Terms

AGIR	Authority Governing Interconnection Requirements
Area EPS Operator	The utility that operated the distribution system. In this document the Area EPS Operator is Minnesota Power.
BPS	Bulk Power System
CT	Current Transformer
DER	Distributed Energy Resource
EPS	Electric Power System
ESS	Energy Storage System
Local EPS	The local electrical system within customer location
LV	Low Voltage
MN DIA	Minnesota Distributed Energy Resource Interconnection Agreement
MN DIP	Minnesota Distributed Energy Resource Interconnection Process
NEC	National Electrical Code
NESC	National Electrical Safety Code
NRTL	Nationally Recognized Testing Laboratory
PoC	Point of Distributed Energy Resource Connection
PCC	Point of Common Coupling
RPA	Reference Point of Applicability
RTO	Regional Transmission Operator
MN DER TIIR	Minnesota Distributed Energy Resource Technical Interconnection and Interoperability Requirements
TPS	Transmission Power System
TSM	Technical Specification Manual
VT	Voltage Transformer

3 Performance Category Assignment

Minnesota Power has no further requirements for performance categories than that provided in the MN

DER TIIR. Performance Category Assignment will be enforced.

3.1 Normal – Category A and B

Minnesota Power currently follows the MN DER TIIR for category assignment. Synchronous machine generation DER shall comply with normal performance category A. Inverter-based DER shall comply with normal performance category B.

3.2 Assignment of Abnormal Performance Category I, II or III

Minnesota Power currently follows the MN DER TIIR for abnormal performance categories. Synchronous machine generation DER shall comply with abnormal performance category I. Inverter-based DER shall comply with abnormal performance category III.

4 Reactive Power Capability and Voltage/Power Control Performance

Synchronous generator based DER shall be capable of providing all voltage and reactive/active power control functions for normal performance category A in IEEE 1547-2018. Inverter-based DER shall be capable of providing all voltage and reactive/active power control functions for normal performance category B in IEEE 1547-2018.

4.1 Constant Fixed Power Factor

The required constant fixed power factor setting will depend greatly on the size and location of the DER within the Area EPS. Large DER installations that go through the study process will often have an ideal power factor specified. However, for DER that do not go through the study process the default settings below shall be used, unless otherwise notified by or arranged with Minnesota Power. The DER system shall maintain this constant fixed power factor at the point of common coupling.

DER System (kVA AC)	Power Factor	Reactive Power Control
< 40 kVA	0.98	Absorbing
40 kVA to < 250 kVA	0.98	Absorbing
250 kVA to < 1 MVA	0.98	Absorbing
1 MVA to 10 MVA	0.98	Absorbing

4.2 Volt-Var Power Control

Minnesota Power requires the settings for Volt-Var Power control to be disabled.

4.3 Voltage and Active Power Control

Minnesota Power requires the settings for Voltage and Active Power control to be disabled.

4.4 Active-Reactive Power Control

Minnesota Power requires the settings for Active-Reactive Power control to be disabled.

4.5 Constant Reactive Power Control

Minnesota Power requires the settings for Constant Reactive Power control to be disabled.

5 Response to Abnormal Conditions

DER systems shall respond appropriately to abnormal conditions that may arise on the Area EPS.

Inverter-based DER shall be able to meet the requirements of IEEE 1547-2018 Abnormal Performance Category III for response to abnormal conditions. Tables 13 and 16 and Figure H.9 of IEEE 1547-2018 are applicable for abnormal voltages and Tables 18 and 19 and Figure H.10 of IEEE 1547-2018 are applicable for abnormal frequencies.

Synchronous DER shall be able to meet the requirements of IEEE 1547-2018 Abnormal Performance Category I for response to abnormal conditions. Tables 11 and 14 and Figure H.7 are applicable for abnormal voltages and Tables 18 and 19 and Figure H.10 of IEEE 1547-2018 are applicable to abnormal frequencies.

Many UL-1741 inverters have multiple certifications and may come pre-loaded with settings that include additional functionality that should be disabled. Care should be taken to ensure that pre-loaded inverter settings are changed to align with the information below.

5.1 Abnormal Voltages

Voltages for use in responding to abnormal conditions shall be measured at the PCC. *Exception: If Area EPS transformer is Wye-grounded/Wye-grounded and the LV system is 4-wire, voltages for use in responding to abnormal conditions may be measured on either side of the Area EPS transformer.*

Applicable voltages for abnormal voltage detection when the PCC is located on the Area EPS side of the transformer are indicated in the table below based on the configuration of the Area EPS. For multiphase systems, the requirements for applicable voltages apply to all phases.

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

Applicable voltages for abnormal voltage detection when the PCC is located on the low-voltage side of the transformer are indicated in the table below based on the low-voltage winding configuration of the Area EPS transformer.

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

5.1.1 Inverter-Based DER

All inverter-based DER shall trip for the abnormal voltage conditions below and clear within the specified clearing time.

Shall Trip – Inverter Based DER		
Shall Trip Function	Default Setting	
	Clearing time (s)	Voltage (p.u. of nominal voltage)
UV2	0.32	0.45
UV1	5.0	0.70
OV1	2.0	1.10
OV2	0.16	1.20

The DER shall ride-through consecutive temporary voltage disturbances in accordance with IEEE 1547-2018 Section 6.4.2.5 and 1547a-2020 requirements for Category III DER.

5.1.2 Synchronous DER

All Synchronous DER shall trip for the abnormal voltage conditions below and clear within the specified clearing time.

Shall Trip – Synchronouse DER		
Shall Trip Function	Default Setting	
	Clearing time (s)	Voltage (p.u. of nominal voltage)
UV2	0.32	0.45
UV1	5.00	0.70
OV1	2.00	1.10
OV2	0.16	1.20

The DER shall ride-through consecutive temporary voltage disturbances in accordance with IEEE 1547-2018 Section 6.4.2.5 requirements for Category I DER.

5.2 Abnormal Frequency

5.2.1 Inverter-Based DER

All inverter-based DER shall trip for abnormal frequency conditions below and clear within the specified clearing time.

Shall Trip – Inverter Based DER		
Shall Trip Function	Default Setting	
	Clearing time (s)	Frequency (Hz)
OF2	0.16	62.0
OF1	300	61.2
UF1	300	58.5
UF2	0.16	56.5

All inverter-based DER shall comply with the rate-of-change-of-frequency ride-through performance requirements per IEEE 1547-2018 section 6.5.2.5.

All inverter-based DER shall comply with the voltage phase angle changes ride-through requirements per IEEE 1547-2018 section 6.5.2.6.

All inverter-based DER shall operate with frequency droop during temporary low and high-frequency ride-through conditions. DER shall comply with the following frequency droop operating parameters.

Parameter	Setting
db_{OF}, db_{UF} (Hz)	0.036
k_{OF}, k_{UF}	0.05
$T_{response}$ (s)	5

5.2.2 Synchronous DER

All Synchronous DER shall trip for the abnormal frequency conditions below and clear within the specified clearing time, unless otherwise specified by Minnesota Power.

Shall Trip – Inverter Based DER		
Shall Trip Function	Default Setting	
	Clearing time (s)	Frequency (Hz)
OF2	0.16	62.0
OF1	300	61.2
UF1	300	58.5
UF2	0.16	56.5

All synchronous DER shall comply with the rate-of-change-of-frequency ride-through performance requirements per IEEE 1547-2018 section 6.5.2.5.

All synchronous DER may operate with a frequency droop during temporary low-frequency ride-through conditions and shall operate with a frequency droop during temporary high-frequency conditions. DER shall comply with the following frequency droop operating parameters.

Parameter	Setting
db_{OF}, db_{UF}* (Hz)	0.036
k_{OF}, k_{UF}*	0.05
$T_{response}$ (s)	5
* = if applicable	

5.3 Dynamic Voltage Support

Minnesota Power requires that Dynamic Voltage Support is disabled at this time.

6 Protection Requirements

6.1 Utility AC Disconnect

A utility AC Disconnect used by the Area EPS to safely isolate the DER shall be supplied by the DER Operator for all DER installations. This disconnect shall be installed between the company owned equipment and the customer's DER, while also being within 10' of Minnesota Power's required production meter. In special circumstances, a variance may be requested due to design/practical limitation. In situations where the system is granted such a variance, pictorial placards shall also be installed at equipment installation locations to depict any and all associated system equipment. In situations where multiple DERs are located on a premise/service point, all DERs shall be controlled by a single disconnect.

The disconnect needs to be accessible 24/7 without escort, capable of being locked open, and provides a visible air-gap separation. The visible open needs to be viewable without unbolting covers or removing other hardware.

Disconnects must be capable of interrupting the rated generator and/or load current..

Disconnects shall not be attached to any Minnesota Power owned equipment or structures.

6.2 Protection Coordination

Overcurrent protection requirements shall meet the NEC requirements for all DER. The first protective device on the DER side of the PCC shall coordinate with Minnesota Power upstream devices.

6.3 Service Protection

6.3.1 Primary Service

All primary voltage electric services are required to provide overcurrent protection at the PCC to prevent tripping of company-owned protective devices for customer-owned equipment failures. Coordination between 12 and 15 cycles between the Minnesota Power owned device and the customer owned device shall be maintained.

6.3.2 Secondary Services

Secondary electric service voltages are required to provide protection of the main service per the NEC. All DER shall be located behind protection meeting this standard.

6.4 Protective Devices

When the DER site installs protective devices, the following requirements shall apply.

6.4.1 Relays

1) All equipment providing relaying functions shall meet or exceed ANSI/IEEE Standards for protective relays.
2) Required relay that are not "draw-out" cased relays shall have test plugs or test switches installed to permit field testing and maintenance of the relay without unwiring or disassembling the equipment. Inverter based protection is excluded from this requirement.
3) Three-phase interconnection shall utilize three-phase power relays, which monitor all three phases of voltage and current.
4) All relays shall be equipped with setting limit ranges at least as wide as specified in IEEE IEEE 1547-2018, and in certain circumstances may be required to meet specifications provided by Minnesota Power. Setting limit ranges are not to be confused with the actual relay settings required for the proper operation of the installation. At a minimum, all protective systems shall meet the requirements established in IEEE 1547-2018a. Over-current relays (IEEE Device 50/51 or 50/51V) shall operate to trip the protecting breaker at a level to ensure protection of the equipment and at a speed to allow proper coordination with other protective devices.
   b. Over-voltage relays (IEEE Device 59) shall operate to trip the Distributed Generation per the requirements of IEEE 1547-2018.
   c. Under-voltage relays (IEEE Device 27) shall operate to trip the Distributed Generation per the requirements of IEEE 1547-2018.
   d. Over-frequency relays (IEEE Device 81O) shall operate to trip the Distributed Generation off-line per the requirements of IEEE 1547-2018.

e. Under-frequency relay (IEEE Device 81U) shall operate to trip the Distributed Generation off-line per the requirements of IEEE 1547-2018. For Generation Systems with an aggregate capacity greater than 250kW, the Distribution Generation shall trip off-line when the frequency drops below 57.0-59.8 Hz. typically this is set at 59.5 Hz, with a trip time of 0.16 seconds, but coordination with Minnesota Power is required for this setting. Minnesota Power will provide the reference frequency of 60 Hz. The Distributed Generation control system must be used to match this reference. The protective relaying in the interconnection system will be expected to maintain the frequency of the output of the Generation.
f. Reverse power relays (IEEE Device 32) (power flowing from the Generation System to Minnesota Power) shall operate to trip the Distributed Generation off-line for a power flow to the system with a maximum time delay of 2.0 seconds.
g. Lockout Relay (IEEE Device 86) is a mechanically locking device which is wired into the close circuit of a breaker or switch and when tripped will prevent any close signal from closing that device. This relay requires that a person manually resets the lockout relay before that device can be reclosed. These relays are used to ensure that a de-energized system is not re-energized by automatic control action and prevents a failed control from auto-reclosing an open breaker or switch. Exceptions: (1) Interrupting device programmed with trip and no reclose may be exempt at Minnesota Power's discretion. (2) Certified inverters and customer breakers may be exempt at Minnesota Power's discretion.
h. Transfer Trip – Transfer trip may be required if Minnesota Power determines that the proposed DER cannot detect and trip for a fault within an acceptable timeframe, or if the DER cannot detect and trip for loss of the utility source.

6.5 Required Protective Devices

Below is a table of the required protective devices for DER. These functions shall be made available either through protective relays, or through protective functions made available by an inverter, provided those functions have been certified through UL 1741-SB.

Type of Interconnection	Over Current (50/51)	Voltage (27/59)	Frequency (81)	Reverse Power (32)	Lockout (86)	Parallel Limit Timer	Sync Check (25)	Transfer Trip
Open Transition Mechanically Interlocked	-	-	-	-	-	-	-	-
Quick Open Transition Mechanically Interlocked	-	-	-	-	Yes	Yes	Yes	-
Closed Transition	-	-	-	-	Yes	Yes	Yes	-
Soft Loading Limited Parallel Operation	Yes	Yes	Yes	Yes	Yes	Yes	Yes	-
Soft Loading Extended Parallel < 250 kW	Yes	Yes	Yes	-	Yes	-	Yes	-
Soft Loading Extended Parallel > 250kW	Yes	Yes	Yes	-	Yes	-	Yes	Yes
Inverter Connections								
< 40 kW	Yes	Yes	Yes	-	Yes	-	-	-
40 kW - 250 kW	Yes	Yes	Yes	-	Yes	-	-	-
> 250 kW	Yes	Yes	Yes	-	Yes	-	-	Yes

6.6 Additional Protection

The DER site is required to remain compliant with IEEE 1547, not cause voltages to exceed ANSI C84.1 ranges, and prevent negative power quality impacts as a result of DER operation. Each DER site will be unique in its impact to these requirements, and will need to be carefully reviewed by the customer for such potential impacts.
Most commonly, for DER sites 100 kW or larger, additional overvoltage relaying and relaying to detect and trip for open phase events are installed at the DER site, although other DER designs may require additional protections. Additional protective devices may serve as supplemental protection to existing protections in a certified inverter. The entire DER site shall maintain compliance with the appropriate standards, regardless of which device is providing the primary protective function. Should the DER site be shown to be inadequate in its protection at any time during its operation, it shall cease operation until such protections are established.

6.7 Open Phase Protection

For open-phase protection, devices relying on undervoltage to detect an open-phase will often not be appropriate due to the presence of delta transformer windings on the DER site. Delta windings allow for voltage regeneration on the open phase which an undervoltage relaying scheme may not be able to detect. Grounded-wye step-up transformers with a three-leg core can allow for voltage regeneration magnetically through flux as well.
Minnesota Power has no preferred method for open phase protection, as long as the DER site is compliant with IEEE 1547 requirements at the PCC.

For synchronous DER, or inverter-based DER that opt not to use the onboard protective functions of the inverter for open-phase detection, special consideration will need to be given to the methodology used to detect and trip for an open phase event.

Typical inverter-based configurations that require additional relaying include:

- Configurations with zig-zag or grounded wye-delta grounding banks
- Configurations with a wye-grounded/wye-grounded 3-leg core step-up transformer.

(1) As required by IEEE 1547, all DER must detect open phase conditions when their output is as low as 5% of their rated output, or, if not capable of producing apparent power at 5% of its rated output, at the lowest output the DER can continue producing apparent power.

(2) Minnesota Power does not recommend a specific method for detecting an open phase condition, as there are many acceptable methods for achieving this. Positive-sequence phase balance, zero-sequence detection and undervoltage relaying are known to be deficient protective schemes and will not be accepted for the purpose of detecting and tripping for an open phase on variable DER systems 100 kw or greater.

   a. Positive-sequence phase balance and zero-sequence detection must set pickup levels above the inherit imbalance on the Area EPS to avoid nuisance tripping. This pickup level will often be too high to allow the protective system to identify an open phase condition when the DER is at 5% output.

   b. Loss of phase via undervoltage relaying detection is inadequate for identifying an open phase condition. Ground banks, delta windings, and three-leg core wye-grounded/wye-grounded transformers present on both the DER site and on the larger Area EPS, may reconstruct voltage on the open phase.

6.8 Grounding

All electrical equipment shall be grounded in accordance with local, state, and federal electrical and safety codes and applicable standards
Grounding of sufficient size to handle the maximum available ground fault current shall be designed and installed to limit step and touch potentials to safe levels as set forth in “IEEE guide for Safety in AC Substation Grounding, ANSI IEEE Standard 80.
It is the responsibility of the Interconnection Customer to provide the required grounding for the DER. IEEE 142-2007 is an appropriate reference for grounding.

All DER sites 100kW or greater in size shall meet IEEE 1547-2018 7.4.1 and 7.4.2. The supplemental grounding requirements below are applicable for all sites 100kW or greater if IEEE 1547-2018 7.4.1 and 7.4.2 are not satisfied by other means.

3-phase DER step-up transformer winding configuration:

Inverter-Based DER

Primary Winding	Secondary Winding	Zero Seq Continuity Maintained	Allowed for DER interconnection when feeder load is >= 50% Line-to-Ground Connected	Allowed for DER interconnection when feeder load is < 50% Line-to-Ground Connected
Wye-grounded	Wye-grounded	Yes (w/ 4-wire LV)	Yes*	Yes (1)
Wye-grounded	Wye	No	Yes	Yes (1)
Wye-grounded	Delta	No	No	Requires Review (2)
Delta	Any	No	Yes	Yes (1)

1.) Requires a supplemental grounding transformer to maintain effective grounding on Area EPS.

2.) Requires supplemental grounding impedance to be installed between the transformer's wye-point and ground.

Synchronous DER

Primary Winding	Secondary Winding	Zero Seq Continuity Maintained	Allowed for DER Interconnection
Wye-grounded	Wye-grounded	Yes (w/ 4-wire LV)	Yes (3)
Wye-grounded	Delta	No	Requires Review (2)
Delta	Any	No	Yes (1)

1.) Requires a supplemental grounding transformer to maintain effective grounding on Area EPS.

2.) Requires a supplemental grounding impedance to be installed between the transformer's wye-point and ground to maintain effective grounding on Area EPS.

3.) DER must be adequately grounded to meet Minnesota Power requirements for effective grounding.

Generators that produce power at line voltage and do not require a step-up transformer must be adequately grounded or have a grounding bank to maintain effective grounding on the Area EPS.Inverter-Based DER

For inverter based DER supplemental grounding transformers, the following requirements shall be met:

1) $X_{0,DER}$= 0.6 p.u. +/- 10% (Note: 1 p.u. is based on $Zbase = kV2$
$MVADER$
)

2) $X0,DER$
$R0,DER$
≥ 4 (Note: this value does not have a +/- 10% tolerance, it shall be ≥4)

3) Ground referencing equipment shall be designed to withstand a minimum of V_0=4% and remain connected (Note: I_0 can be approximated as $I_0=V_0/Z_0$).

4) Ground referencing equipment shall have a 5-second withstand rating that exceeds maximum available short-circuit current for close in faults

5) Loss of ground referencing equipment shall immediately trip the DER.

Machine-Based DER

For machine-based DER, supplemental grounding shall comply with traditional IEEE grounding standards. To achieve effective grounding, an Interconnection Customer's system equivalent (Thevenin equivalent impedance) must meet the two criteria given below or otherwise meet a coefficient of grounding of 80%, also see IEEE 32 and IEEE C62.92.2.
Note – the effective grounding impedance is always determined with the generator separated from the Area EPS. Momentary fault withstand and continuous current ratings are always determined with the Area EPS and generator connected.
1.) The positive sequence reactance is greater than the zero sequence resistance ($X_1 > R_0$).
2.) The zero sequence reactance is less than or equal to three times the positive sequence reactance. The Area EPS Operator requires the ratio to be between 2.0 and 2.5 ($2.0*X_1 < X_o < 2.5*X_1$) to limit the adverse impacts on feeder ground relay coordination.

When calculating faults and effective grounding using the positive, negative, and zero sequence impedance networks, the networks shall include impedances for the following: the step-up transformer, generator subtransient reactance (Xd”), neutral grounding reactance on the step-up transformer and/or generator, secondary cable runs greater than 50 feet in length, and the grounding bank. For induction generators, the equivalent of the subtransient reactance shall be used. If the Xd” equivalent is not available, the following approximation is usually adequate: X = (Rated Voltage / Locked Rotor Current) ohms.

The Interconnection Customer shall submit the grounding device information for approval before it is purchased. Many different system configurations will meet the effective grounding requirements. Listed below are some guidelines and restrictions.

Neutral reactors may be required in a number of configurations for both rotating generators and inverters. A reactor has four ratings; reactance, continuous current rating, maximum current withstand for a maximum duration, and a voltage rating. The voltage rating for an air core reactor shall exceed the with-stand current times the reactance. If the voltage rating is for an iron core reactor, it must exceed the current times reactance plus a margin to ensure the reactor does not saturate under fault conditions. The lesser of 125% of current times reactance or full line-neutral voltage is suggested.

The Interconnection Customer's equipment must be able to withstand allowable voltage imbalances and be able to operate during an imbalance condition. A V0 sequence voltage of 4% is recommended for determining the continuous imbalance rating.

7 Operations

7.1 Periodical Testing & Record Keeping

All interconnection-related protection and control systems shall be periodically tested and maintained, by the Interconnection Customer, at intervals specified by the manufacturer or system integrator and shall not exceed 10 years. Periodic test reports and a log of inspections shall be maintained by the Interconnection Customer and made available to the Area EPS operator upon request. The Area EPS operator shall be notified prior to the testing of the protective and control systems to witness the testing if so desired. The testing procedure for re-test should be a functional test of the protection and control systems.

Any system that relies on batteries for trip or protection power should be checked regularly for proper voltage.

7.2 Power Ramp Rates

Minnesota Power limits the maximum voltage step change of 3% for DER interconnections. This is to limit negative impacts on other customers and the distribution system. In addition, DER systems shall not cause the Area EPS voltage to deviate from ANSI range A voltage levels. Block loading or off-loading of DERs that cause voltage step changes greater than 3% are not allowed.

7.3 Enter Service

Enter Service refers to whenever a DER is starting to operate, whether after a power outage or during normal operations of the DER. How a DER Enters Service is important to the reliability and performance of the Local EPS. See below for some potential Enter Service requirements.

7.3.1 Non-Energy Storage Systems

- The delay time for restarting of the DER after an outage may be increased
- The DER shall stagger the restarting of inverters under normal restarting and after an outage
- Multiple transfer switches may be required for block loading to limit load transfer amount

7.3.2 ESS

ESS systems can affect the Area EPS through large step changes. Please refer to the ESS Section for Enter Service requirements.

- The discharging of the ESS may require a predefined ramp rate
- The delay time for restarting of the DER after an outage may be increased
- The charging of the ESS may require a predefined ramp rate

8 Power Control Systems

8.1 General

Power control systems are used to control the output from a DER system due to an external condition. For example, the output from a DER unit may be limited so that it does not export energy back into the Area EPS system at the PCC. To accomplish this the power control system senses the flow of energy at the PCC and relays that information back to the DER to control the DER output to ensure no reverse energy flow at the PCC during abnormal operating conditions.

8.1.1 Power Control System Requirements

The power control system must be NRTL certified and meets the following requirements.

(1) Able to halt or reduce energy production within two seconds after either the period of continuous export to the Area EPS exceeds 30 seconds or the level of export exceeds the lessor of 100kW or 10% of the DER nameplate rating

(2) Able to monitor that the total energy exported

(3) Able to self-monitor the Power Control System, such that failure of the ability to monitor the energy flow or failure of the ability to control the output of the DER, results in halting the production of energy by the DER or the separation of the DER system from parallel operation with the Area EPS

(4) The configuration and settings governing the power control limiting functions shall be password protected, accessible only by qualified personnel

(5) The power to the control system must be battery backed up and if the power to the control is not available the DER system must be blocked from operation

8.1.2 Common Control Modes (non-ESS)

There are many possible configurations and associated reasons for implementing a power control system for the DER installation. The following are a few of the more common control modes as defined in the UL 1741 CRD standard.

(1) <u>Unrestricted Mode</u> – The DER may import active power from the Area EPS while charging and may export active power to the Area EPS while charging

(2) <u>Export Only Mode</u> – The DER may export active power to the Area EPS during discharging but shall not import active power from the Area EPS for ESS charging purposes.

(3) <u>Import Only Mode</u> – The DER may import active power from the Area EPS for ESS charging purposes but shall not export active power from the DER to the Area EPS

(4) <u>No Exchange Mode</u> – The DER shall not exchange active power with the Area EPS for charging or discharging.

8.1.3 Documentation

The following information is a generic listing of information which may be required to be provided to Minnesota Power as part of the application filing, if the DER system relies on the power system control to limit the output of the DER and/or limits the charging of a the DER ESS. Generally, the Minnesota Power engineer will need enough information to understand how the power control system will work; how it will be installed; what the intended function(s) of the power control system are and how the monitoring will be accomplished.

(1) Manufacture and model of the power control system

(2) Electrical schematic of the power control system monitoring

(3) User manual for the power control system control

(4) Response time to modifying the output of the DER, in response to a large step change in the local electrical loads.

(5) Description of the operating reason and modes (from the user manual) which will be utilized. For example, “the power control system is designed to only allow importing of energy and will modify the DER operation to eliminate all exporting across the PCC”

(6) Description of how other possible operating modes (shown in the user manual) are being restricted so they are not able to be enabled

8.1.4 Inadvertent Export

Inadvertent export is the flow of energy, in excess of a defined amount, through the PCC and back into the Area EPS system. Inadvertent export may occur during sudden changes in local electrical demand and must be quickly resolved through the automatic adjustment of the DER output through the direction of the power control system.

Inadvertent export, if it is large enough could damage Area EPS equipment or cause tripping and a power outage. For DER systems which are designed as non-exporting, the Area EPS has not been constructed to support the reverse flow of energy and may not be able to support it.

Inadvertent Export shall be limited to 10% of the DER nameplate rating or 100kW, whichever is less, for a maximum of 30 seconds. The Power Control System shall be designed to limit inadvertent export to these levels, unless otherwise mutually agreed to between the Area EPS and the DER operator and documented in the operating section of the interconnection agreement.

9 Interoperability

The size of the interconnecting DER dictates the level of monitoring and control Minnesota Power needs to have over the DER system. Larger systems often can have a much more significant impact on the electric distribution system and need more advanced monitoring.

9.1 Remote Monitoring (Telemetry)

For all DER 250 kW or greater, remote monitoring of the DER production is required. The specific communication method will depend on the location of the DER installation. Below is a list of status points that Minnesota Power expects the DER to send to the Minnesota Power SCADA system.

- Status Points
  - Status of any lockout relay
  - Status (open/close) of the interconnection breaker(s) or if transfer switch is used, status of each transfer switch. Hard wired from monitoring RTU directly to the breaker, not supervised by the breaker relay.
  - High voltage alarm (settings defined by DEA)
  - Low voltage alarm (setting defined by DEA)
  - DC supply / charger trouble alarm
  - Trouble alarm (relay failure alarm) from each protective relay providing the utility required protection elements.o General Trouble Alarm, can be a common alarm or individual alarms, need to include generation control trouble, issues with DC voltage.

- Control Points
  - Remote control of interconnection breaker (open / close) hard wired from Minnesota Power RTU directly to the breaker, not supervised by the breaker relay.
  - Ability to start and stop DER and transfer load off the system. (if required for interruptible rate)
  - Ability to remotely turn on/off modes of operation, and/or monitor which modes of operation are active (if applicable)

- Analog Values (Values updated at least every 10 seconds)
  - Individual phase voltage values representative of the Area EPS's service to the facility.
  - Individual Phase amps (DER output)
  - DC voltage from protective DC battery
  - 3 Phase Real (kW) and reactive (kVAR) power flow for each DER unit.
  - Total Current harmonic distortion (Current THD)
  - Total Voltage harmonic distortion (Voltage THD)

This list may change based on the design and use case of the DER.

9.2 Direct Transfer Trip

In special circumstances Minnesota Power may require direct transfer trip of DER. This involved the utility sending a signal to a customer owned recloser or breaker to disconnect from the Local EPS. DTT may need to be used based on the size of the DER and relative system loading or other unique system conditions that are identified during the study process.

9.3 Reclose Blocking

Provisions for hot bus/dead line supervision of reclosing on the distribution feeder's substation breaker is required when aggregate DER generation exceeds 80% of minimum annual distribution feeder load. The need for reclose blocking will be reviewed with the interconnection study of each DER facility.

9.4 Minnesota Power Recloser

All DER ≥ 1000kW require a Minnesota Power owned recloser to be installed on Minnesota Power's distribution system. DER ≥ 500kW and < 1000kW may require a Minnesota Power owned recloser to be installed on Minnesota Power's distribution system to provide coordination for fault protection.

9.5 Overvoltage Protection

If DER generation is >= 80% of minimum feeder load, overvoltage protection may be required at the primary side of the feeder's substation transformer to prevent line-to-neutral overvoltage conditions on the primary circuit caused by persistent ground faults and the loss of the primary circuit's utility source.

9.6 Security

9.6.1 Physical and Front Panel

It is the responsibility of the DER Operator to maintain physical security for equipment and all communication interfaces at the DER site. The configuration settings for all DER equipment that provide protection or control shall be password protected to allow access only to qualified personnel.

9.6.2 Network Security

It is the DER Operators responsibility to ensure cyber security of any DER equipment or DER communication equipment provide by the DER Operator. The DER Operator is responsible for ensuring that there are no possible cyber connections with the internet through DER Operator communication systems which are also connected to the Minnesota Power communication system. The communication link between any piece of equipment and the Minnesota Power equipment shall be a direct link and not a shared communication channel with any other communication.

10 Energy Storage Systems (ESS)

10.1 General

10.1.1 Non-Applicable to Grid Services

Since the requirements and tariffs for distribution connected Energy Storage Systems providing grid support functions, such as frequency or voltage support have not yet been developed, the TSM is not written to cover the issues involved with the use of ESS for grid services. Until such time as the MISO rules and the required Minnesota PUC tariffs are developed and approved, the use of ESS to provide grid services is not permitted.

10.1.2 Defining Common Modes of Operations

The following defines a set of common operational modes for Energy Storage Systems (ESS). One or more of these operating modes can be selected in the DER interconnection application. The process used to review the ESS interconnection application will depend upon which of the modes have been selected. If the ESS will have the capability of operating in more than one operating mode, then all the operating modes must be listed on the interconnection application so that they can be studied by Minnesota Power.

10.1.3 Emergency Power

This operating mode is designed so the ESS is only providing energy to the Local EPS during a power outage and will not be providing energy to the Local EPS at other times. Selecting this mode requires the interconnection with the Area EPS is severed when supplying power to the Local EPS. The ESS is normally sitting fully charged, waiting for a power outage.

After the power outage the ESS needs to be recharged. Immediately recharging the ESS after a power outage, will create a greater demand upon the Area EPS than is typical and may result in placing an increased the demand on the Area EPS and the local service. This could create higher demand charges and/or overload the Area EPS. To help eliminate this risk, the ESS is requested to delay the recharging of the ESS for 30 minutes after restoration of the power outage. The ESS is required to keep supplying the local load connected to the ESS for at least 5 minutes after restoration of power on the ESS.

10.1.4 Demand Reduction Management

This mode is so the ESS is used to reduce the peak demand of the Local EPS. This is sometimes also called peak shaving or peak load reduction. The ESS is operating to reduce the peak demand of the Local EPS and is often controlled by a Power Control System that is monitoring the total load of the Local EPS. The ESS outputs energy into the Local EPS during peak load periods to offset the purchase of energy from the Area EPS. With this operating mode the ESS has the potential to back feed the Area EPS during events, such as faults on the Area EPS or step load changes in the Local EPS.

The charging of the ESS is typically limited to periods when the Local EPS loads are minimal.

10.1.5 Non-Exporting/Self-Consumption

This mode for an ESS is used to store energy during the day for use during other times of the day. This could be used to charge during the evening for use during the day with a time-of-use rate, or, used as a form of net metering for systems which are larger than40kW to not export excess renewable energy to the utility so it can be used by the Local EPS at other times.

10.1.6 Enter Service

After any sustained electrical outage, the energy storage system shall be configured to not immediately initiate recharging of the ESS. Per the IEEE 1547 standards the ESS shall wait a minimum of 5 minutes after the Area EPS is reenergized and provides a stable voltage, before initiating recharging of the ESS.

It is preferable to delay any recharging of the ESS for a minimum of 10 minutes after re-energization of the Area EPS, to allow the distribution system to fully stabilize and reduce the possibility of additional electrical demand caused by the recharging of the ESS to overload the distribution system.

To help reduce the possibility of step voltage issues and other distribution system issues, it is preferable to have the ESS control system ramp up the recharging level from 0-100% over a 5-minute time period upon entering service.

10.1.7 Modification of Operating Modes

The ESS control system must be secured and password protected so that operating modes which have not been studied and approved by Minnesota Power cannot be utilized. The ability for the homeowner, business owner or employee of the business to turn on additional not reviewed and unapproved modes shall be strictly controlled. Only qualified service personal shall have access to turning on additional modes of operation.

11 Metering

11.1 Introduction

This section contains specifications for metering on DER with interconnection Minnesota Power. While these specifications are applicable for the majority of the interconnections, there are always unique installations which may require deviations from these standards. Deviations from this specification must be reviewed and approved in writing by Minnesota Power'sengineer prior to implementation. Additional requirements due to deviations from this specification will be at the cost of the interconnection customer.

There are two types of meters needed for a DER system. The first, a main meter, is located at the PCC, unless mutually agreed upon between the Area EPS Operator and Interconnection Customer, and is what the Area EPS Operator shall use for billings purposes. This is commonly a bidirectional meter. The second, a production meter, is located electrically at the PoC. This meter will monitor the power flow to and from the DER. The production meter may be used for incentive programs and provides the Area EPS Operator with necessary information to properly engineer a safe and reliable grid. Production meter sockets are supplied by Minnesota Power for self contained installations. If services require CT rated installations, then Minnesota Power will supply CTs, VTs, and CT rated sockets and the customer shall supply the CT enclosure and VT enclosure if required.

A DER system shall have both types of meters, main and production, installed as part of the DER system. For DER systems where the PCC and PoC is the same location a single meter can perform both types of metering.

11.2 Meter Socket

The interconnection owner is responsible for purchasing and installing a meter socket that meets the following requirements and is appropriate for the service connect.

1) Must be UL (Underwriters Laboratories) or ARL (Applied Research Laboratories) approved
2) All self-contained meter sockets, whether sub-meter, or main service; shall use a lever actuated jaw clamping positive by-pass mechanism
3) All meter sockets for transformer rated installations using CT's, will be furnished by Minnesota Power.
4) Shall be ring-less style
5) Equipped with a track resistant polycarbonate insulating safety shield.
6) 480 Volt self-contained metering shall be done by exception only. Standard install is CT Rated with a VT cabinet for any amperage.
7) Full list of metering requirements can be found in the construction guide at mnpower.com

11.3 Secondary

Metering on the secondary system is the most common application. The Interconnection Customer shall install a meter socket per the following specifications. For Standard meter form installations will be 2S/4S/9S/16S.

1) All interconnections rated at 200A or less and less than 240 volts will use self-contained meters.
2) All interconnections rated at greater than 200A shall use meter CTs with the exception of 120/240 single phase 400 amp self-contained is allowed.
3) All interconnections rated at greater than 240V shall use meter CTs and VTs

For applications 2 & 3 above the CTs, VTs and CT rated sockets shall be supplied by Minnesota Power. The interconnection customer shall install and furnish an enclosure for the CTs and VTs per the construction guides found at mnpower.com

11.4 Primary

Metering on the primary distribution system is non typical and engineered on a case-by-case basis, consult Minnesota Power directly.

11.5 Location and Accessibility

The meter socket must be mounded in a location that meets the following specifications:

1) The center of the meter shall be located at a height between 4 to 6 feet above the ground.
2) Location and path to the meter must be clear and free of hazards for anyone accessing the meter
3) Accessibility by Minnesota power 24/7, with open walkway to/from the meter, that is clear of shrubs, brushes etc.
4) Solidly mounted on a permanent structure, not on a fence of other semi-permanent structure, so that they maintain a vertical position, (i.e., side of building)
5) Free from interference with traffic on sidewalks or driveways
6) Located so that it is not subject to damage from excessive moisture or vibrations, snowplows, falling ice from roofs or ice flows etc.
7) Meters must be a minimum of 3 feet away from a gas meter, and 6 feet away from combustible storage.
8) Meter shall have unobstructed space of at least 3 feet in front and 1 foot to each side
9) There must be 10 ft of unobstructed clearance in front of the CT cabinet doors to facilitate maintenance such as CT testing.
10) A full list of requirements can be found in the construction guides at mnpower.com

The specifications for meter socket location and accessibility shall be maintained for the life of the meter use. If changes cause the meter to no longer meet the above specifications the meter shall be moved to a new accessible location at the expense of the interconnection customer.

12 Signage and Labeling

12.1 General

All signage and labelling shall be in accordance with NEC. In order to provide a safe operating environment for Minnesota Power personnel, several additional labelling and signage requirements will need to be met.

12.2 AC Disconnect

The Utility AC disconnect shall be labeled as “DER Utility AC Disconnect”

If a single Utility AC Disconnect cannot be used to disconnect all DERs, all Utility AC disconnects should include numerical identification such as “Utility DER AC Disconnect 1 of 2” or similar. The number of disconnects required to be operated to isolate the DER from the utility should be clear.

AC disconnect cannot be attached to any Minnesota Power owned facilities such as a pole or meter pedestals.

12.3 Main Meter

A sign at the main service meter shall indicate that DER is present. Each type of DER present shall be listed. The sign shall provide clear direction to the distance and location of all DER utility AC disconnects. A map shall include outline of all structures in the area and compass arrow for orientation.

12.4 Production Meter

The production meter shall be labeled as “Production Meter”.

Production meter sockets cannot be attached to any Minnesota Power owned facilities such as a pole or meter pedestals.

12.5 Equipment Variances

Any systems that have been granted a variance for equipment locations shall have installed pictorial placards showing location of all associated equipment at each location where equipment is located.

13 Test and Verification Requirements

13.1 UL 1741 Type-Tested Equipment

Minnesota Distributed Energy Resources Interconnection Process Attachment 5, Certification of Distributed Energy Resource Equipment, contains requirements for DER to be considered certified. In practice, this certification is recognized as UL 1741-SB for inverter-based DER. DER certified to UL 1741-SB will typically have fewer testing requirements than non-certified equipment. Currently, UL 1741-SB certification only applies to the inverter itself, but IEEE 1547 is applicable to the complete DER installation. Aggregated inverters, supplemental devices such as ground reference banks, or additional protective relays may cause the behavior of the DER system to not be compliant with IEEE 1547-2018 if not carefully reviewed. Usage of UL 1741-SB certified inverters may only partially fulfill the complete installation’s compliance with IEEE 1547-2018. Additional protective relays or equipment settings changes may be required to achieve compliance. Manufacturer recommendations should be followed, and for more complex installations where UL 1741-SB certified functionality is achieved through non-certified equipment, a professional engineer may need to be consulted to evaluate compliance with IEEE 1547-2018. The usage of UL 1741-SB certified inverters will reduce the scope of commissioning testing. For inverter-based systems, non-UL 1741 certified inverters are not eligible for interconnection with Minnesota Power’s Area EPS.

The use of UL 1741-SB certified inverters does not automatically qualify the Interconnection Customer to be interconnected to the Area EPS. An application will still need to be submitted and an interconnection review may still need to be performed to determine the compatibility of the DER with the Area EPS.

Non-UL 1741-SB certified DER still must meet the requirements of IEEE 1547-2018, the TIIR, and the TSM. All devices used to achieve these requirements must be tested, and a report of the testing must be provided to Minnesota Power upon request. For UL 1741-SB certified DER that use supplemental devices to achieve compliance with IEEE 1547-2018, the TIIR, and the TSM, these devices must also be tested, and a report of the testing must be provided to Minnesota Power upon request. Minnesota Power may request to witness these tests on-site.

13.2 Commissioning Testing

The following tests shall be completed by the Interconnection Customer. All of the required tests in each section shall be completed prior to moving on to the next section of tests. Minnesota Power has the right to witness all field testing and to review all records prior to authorizing the system to operate. Minnesota Power shall be notified, with sufficient lead time to allow the opportunity for Area EPS personnel to witness any or all of the testing. All witness test dates are subject to availability of MP personnel.

13.2.1 Pre-Energized Testing

The following tests are required to be completed on the DER prior to energization. Only qualified personnel shall perform and sign-off on these tests. Written verification of each of these tests shall be made available to the Area EPS upon request.

1) Grounding shall be verified to ensure that it complies with this standard, the NESC and the NEC

    a) Verify that the equipment safety ground connections and other associated grounding equipment comply with the TIIR, TSM, NEC and NESC requirements.

    b) The interconnection customer shall provide a final factory nameplate drawing, as-built, of all ground referencing equipment 15 business days prior to the witness test.

2) CT's and VT's used for monitoring and protection, shall be tested to ensure correct polarity, ratio and wiring and verified installed as indicated in Area EPS approved design drawings.

3) CT's shall be visually inspected to ensure that all grounding and shorting connections have been removed where required.

4) Breaker and Switch tests - Verify that the breaker or switch cannot be operated with interlocks in place or that the breaker or switch cannot be operated remotely or automatically when in manual mode. Various DER Systems have different interlocks, local or manual modes, etc. The intent of this section is to ensure that the breaker or switches controls are operating properly.

5) Relay Tests - All Protective relays shall be calibrated and tested to ensure the correct operation of the protective element. Documentation of all relay calibration tests and settings shall be provided to the Area EPS operator upon request.

6) Trip Checks - Protective relaying shall be functionally tested to ensure the correct operation of the complete system. Functional testing requires that the complete system is operated by the injection of current and/or voltage to trigger the relay element and proving that the relay element trips the required breaker, lockout relay or provides the correct signal to the next control element. Trip circuits shall be proven through the entire scheme (including breaker trip). For inverters, a UL 1741 certification is adequate to satisfy the functional testing requirements of the internal inverter functions.

7) Remote Control, SCADA and Remote Monitoring tests - All remote control functions and remote monitoring points shall be verified operational. In some cases, it may not be possible to verify all of the analog values prior to energization. Where appropriate, those points may be verified during the energization process

8) Phase Tests - the Interconnection Customer shall work with the Area EPS operator to complete the phase test to ensure proper phase rotation of the DER and wiring. UL 1741 certified inverters that do not intentionally island are not required to perform this test.

9) Synchronizing test - The following tests shall be done across an open switch or racked out breaker:

   a) The switch or breaker shall be in a position that it is incapable of closing between the DER and the Area EPS for this test. This test shall demonstrate that at the moment of the paralleling-device closure, the frequency, voltage and phase angle are within the required ranges, stated in IEEE 1547-2018.

   b) A test shall also demonstrate that if any of the parameters are outside of the ranges stated, the paralleling-device shall not close.

   c) For UL 1741 certified inverter systems, this test may not be required unless the inverter creates fundamental voltages before the paralleling device is closed, such as in a micro-grid or intentional island.

13.2.2 Energized Commissioning Test

The following tests will proceed once the DER has completed Pre-Energized Testing and the results have been reviewed and approved by the Area EPS operator. Updated as-built drawings, inverter settings, relay settings, grounding calculations, or any other applicable information should be provided to the Area EPS prior to the scheduled witness test. . All energized commissioning tests shall be based on written test procedures agreed to between the Area EPS operator and the Interconnection Customer. The location and method of measurement shall be listed for each step. The Interconnection Customer shall provide qualified personnel and supply proper equipment to adequately record the results of the tests.

The Energized Commissioning Test will require the following steps, at minimum:

1) Verification that 24/7 unescorted access is available

   a) Site access includes drivable and keyless access to all MP needed equipment

2) Verification that the DER Installation matches the Minnesota Power approved as-built one-lines

3) Verification of proper labelling

4) The Interconnection customer shall verify that the settings and firmware for inverters, protective devices, power control systems, or other control hardware and software are in

   compliance with the TSM, TIIR, Operating Agreements and match previously approved settings.

5) Anti-Islanding Test - For DER that parallel with the utility for longer than 100msec, the following test steps shall be performed to verify compliance with IEEE 1547-2018. IEEE 1547.1-2020should be referenced for evaluation of acceptable testing procedures.

   a) The DER shall be started and connected in parallel with the MP source.
      i) The steps required to energize the DER and parallel with the utility shall be listed. This may include closing a number of disconnects and/or fuses.

ii) Current, voltage, and power factor shall be confirmed.

iii) For PV systems, this test needs to occur during the daytime with enough irradiance to produce at least 5% of each individual inverters nameplate kW rating. For sites that cannot achieve output greater than 15% of the DER nameplate rating, a fixed metering device such as an inverter display or customer owned check meter shall be used for current verification so as to be able to determine the direction of power flow. When the output of the DER is greater than 15% of the nameplate rating, a handheld or portable meter to measure currents may be used. For multi-phase DER, the customer shall monitor all phases simultaneously.

b) The Minnesota Power source shall be removed by opening a device such as a switch, breaker, etc.

i) The switching device shall be located such that all anti-islanding protective devices are tested simultaneously.

ii) The switching device shall be located such that it is between the utility source and any ground referencing equipment, if applicable.

iii) For three-phase DER, this test shall be applied separately to all individual phases as well as all three-phases simultaneously. The testing shall be performed on the utility side of the PCC unless otherwise agreed upon.

c) The DER shall either separate with the local load or stop generating within 2 seconds.

i) Any voltages present on the DER side of the test point shall be verified as less than 110% of the nominal voltage.

d) The device that was opened to remove the Area EPS source shall be closed and the DER shall not re-parallel with the Area EPS for at least 5 minutes, or per a mutually agreed upon enter service time.

13.2.3 Periodic Testing and Record Keeping

Minnesota Power shall be notified any time that substantial changes and modifications are made the DER installation. This notification shall be as early as possible so that Minnesota Power may be involved if necessary for modifications or further verification testing.

All interconnection-related protection systems shall be periodically tested and maintained by the Interconnection Customer at intervals specified by the manufacturer or system integrator. These

intervals shall not exceed 5 years. Periodic test reports and a log of inspections shall be maintained by the Interconnection Customer and made available to the Area EPS operator upon request. The Area EPS operator shall be notified prior to the period testing of the protective systems, so that Area EPS personnel may witness the testing if so desired.

Any system that depends upon a battery for trip/protection power shall be checked and logged once per month for proper voltage. Once every four years the battery(s) must be either replaced or a discharge test performed. Longer intervals are possible through the use of “station class batteries” and Area EPS operator approval.

14 Sample Documents for Simplified Process

14.1 One-line diagram

Please refer to the Minnesota Power “Consumer Guide to Solar” for example diagrams, which can be found at https://www.mnpower.com/Environment/CustomerSolar.

14.2 Site diagram

Please refer to the Minnesota Power “Consumer Guide to Solar” for example diagrams, which can be found at https://www.mnpower.com/Environment/CustomerSolar.

14.3 Testing procedure

Minnesota Power may supply a checklist for testing upon request.