City of Saint Peter Technical Specification Manual

Introduction

This Technical Specification Manual (TSM) has been developed as a companion document to the Minnesota TIIR (Technical Interconnection and Interoperability Requirements) document. This TSM applies to all Distributed Energy Resources (DER) that are interconnected with the City of Saint Peter distribution system. Both the TIIR and TSM documents are based upon the IEEE 1547 standards and other applicable national standards.

The TSM is expected to be updated on a regular basis as DER technology and interconnection standards change. DER Vendors and Applicants should confirm they are using the latest TSM version when designing their DER system. Special attention should be made to Annex C of the TIIR. The information in Annex C addressing interim technical guidance is included in this version of the TSM.

This TSM provides specific information about interconnecting a DER with the City of Saint Peter electrical distribution system (Area EPS). The TSM applies to DER with an aggregate Nameplate Rating of 10 MW or less at the Point of Common Coupling. The TSM applies to all DER which are capable of paralleling with distribution facilities for a brief period, or for extended operation.

The TSM has been written to cover the most common DER interconnection issues, but there will be unique DER interconnections which may require additional interaction between City of Saint Peter and the proposed DER installer. Prior to purchasing equipment, if the TSM does not provide guidance for a specific type or style of interconnection or if there are questions, it is recommended that the Interconnection Customer contact the City of Saint Peter DER interconnection coordinator. Failure to meet the requirements for interconnection with the Area EPS may result in denial of the interconnection request or disconnection of the interconnection.

NOTE:
It is encouraged that an application for interconnection of a DER is submitted to the City of Saint Peter before ordering the DER equipment to avoid additional costs or delays with the project. Applying for interconnection will trigger a design review by the AREA EPS staff. If this review identifies technical issues with the interconnection location, type, or design, it is easier to resolve these issues if the DER equipment has not been ordered.

The IEEE Std 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems, is the primary standard for interconnection requirements. Other IEEE, ANSI, and NESC requirements are applicable to the interconnection of DER, including energy storage systems. The National Electric Code (NEC) is required to be followed for all electrical equipment installed on the customers side of the City of Saint Peter meter and all DER installations are required to be inspected by the local area electrical inspector prior to interconnection with the City of Saint Peter system. As required by Minnesota State law, the Area EPS will require proof of compliance with the National Electrical Code before the interconnection is made, through installation approval by an electrical inspector recognized by the Minnesota State Board of Electricity.

The proposed DER system(s) cannot adversely impact power quality or reduce the reliability to the other customers connected to the Area EPS. The interconnection of a new DER facility to the Area EPS must not degrade the existing protection and control schemes nor lower the existing levels of safety and reliability for other customers.

This standard only covers the technical requirements and does not cover the interconnection process from the planning of a project through approval and construction. Please read the companion document Minnesota Municipal Interconnection Process (M-MIP) for the procedure to follow and a generic version of the forms to submit.

1. General Information

1.1. Application of IEEE 1547-2018 Standards

The IEEE 1547-2018 standard has been approved and is available for use as the national standard for interconnection and interoperability of distributed energy resources with electric power systems. Currently, no equipment used to provide DER interconnections has been certified to meet the new IEEE 1547.1-2018 requirements. So, this document has been written such that the requirements for interconnection are assuming that the equipment being used complies with the IEEE 1547a-2014 requirements.

In some cases, this document also provides guidance to support the use of equipment which can meet the requirements of the new IEEE 1547-2018 standard. As stated in the TIIR "*At such time certified equipment first becomes available, the Area EPS Operator and the DER Owner may mutually agree to utilize the certified equipment and functionalities in conformance with the requirements of IEEE 1547-2018*".

1.1.1. References and Definitions

The references and the definitions from the IEEE 1547-2018 and Minnesota TIIR documents are applicable for this document. *Italicized words* or sections in this document are direct references to information contained within the TIIR.

1.1.2. Certified Inverter

An inverter is considered certified if it meets the requirements listed in the most current standard for IEEE 1547. The 2018 version and the associated testing procedure IEEE 1547.1-2018 is still under development. So, the IEEE 1547a-2014 and the associated IEEE 1547.1a is the most recent version available for certification.

1.1.3. DER Installations using Open Transfer Switch

For a DER installation to qualify as an open transition switch installation and the associated limited protective requirements, mechanical interlocks are required between the two source contacts. (Area EPS source and DER source) This is required to ensure that one of the contacts is always open and the DER can never be operated in parallel with the Area EPS. If the mechanical interlock is not present, the protection requirements are as if the switch is a closed transition switch that can parallel with the Area EPS. This requirement is due to the possibility that the solenoid operating a source contact can fail and parallel the DER with the Area EPS. Open Transition switches, with a mechanical interlock between the source contactors are exempt from submitting an interconnection application to the Area EPS.

1.1.5. Area EPS Modifications

Depending upon the location of the interconnection, size of the DER and how the DER is operated, certain modifications and/or additions may be required to the existing Area EPS due to the addition of the DER. As part of the application and review process, any modifications required to the Area EPS will be identified along with the estimated costs which will be incurred by the DER applicant.

1.1.6. Distributed Energy Resource (DER) System Protection

Protection requirements in the TIIR and TSM are structured to protect the Area EPS, Area EPS customers, and the public. 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. Additional protection equipment, beyond what is required within this TSM may be required to ensure proper operation of the DER. This is especially true while operating islanded from the Area EPS. The City of Saint Peter does not assume responsibility for the protection of the DER equipment.

1.1.7. Bulk Transmission System Requirements

The TSM document provides the requirements associated with the City of Saint Peter distribution system. This TSM document does not include any of the requirements which may apply due to interaction of the proposed DER and the bulk transmission system. The city of Saint Peter distribution system is interconnected with the bulk transmission system and the interconnection and operation of the proposed DER may affect the transmission system. If the potential for affecting the transmission system is identified through the interconnection application process, City of Saint Peter together with the DER interconnection applicant will need to work with the area transmission provider to identify any additional operational or interconnection limitations and the interconnection requirements that may be necessary due to transmission constraints.

1.1.8. Aggregation and Coordination of DER Operations at Multiple Sites

Aggregated and coordinated operation of DER for the purpose of selling those services to a transmission market, is not allowed without written permission of City of Saint Peter. For example, the use of multiple DER systems to provide frequency response or coordinated load control and sell that service to the MISO market, is not allowed on the Area EPS without written approval of City of Saint Peter.

1.1.9. Design and Maintenance of DER Facilities

City of Saint Peter review and approval of the interconnection of the DER system, is not a complete design and operational review of the DER system and does not relieve the DER Operator of its responsibility, to design, install, test, operate and maintain the DER system in a manner which is safe. The DER Operator is responsible to ensure that the DER system is designed, operated, and maintained so that it does not energize a de-energized portion of the Area EPS or injects inadvertent energy into the Area EPS which causes equipment damage, injuries or affects the reliable flow of electricity to other Area EPS customers.

2. Abbreviations and Common Terms

2.1. Abbreviations

AGIR	**Authorizing Governing Interconnection Requirements**
Area EPS	**Area Electrical Power System**
BPS	**Bulk Power System**
DER	**Distributed Energy Resource**
EPS	**Electric Power System**
ESS	**Energy Storage System**
Local EPS	**Local Electrical Power System**
DIA	**Distributed Energy Resource Interconnection Agreement**
DIP	**Distributed Energy Resource Interconnection Process**
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 Specifications Manual**

2.2. Key Terms

The terms used in this document are defined in the MN DER TIIR. For quick reference, the key terms are further explained in this section.

Area Electric Power System (Area EPS): The electric power distribution system connected at the Point of Common Coupling. City of Saint Peter is the Area EPS for this TSM document, and the term Area EPS and City of Saint Peter are used interchangeably.

Area Electric Power System Operator (Area EPS Operator): An entity that owns, controls, or operates the electric power distribution system that is used for the provision of electric service. City of Saint Peter is the Area EPS Operator for this TSM document.

Local Electric Power System (Local EPS): An EPS contained entirely within a single premise or group of premises. The Local EPS is the local electrical system in the house or business.

Point of Common Coupling (PCC): The point of connection between the Area EPS and the Local EPS. For residential services this is the main City of Saint Peter revenue meter. For commercial services this is typically at the secondary of the distribution transformer or at the main City of Saint Peter revenue meter.

Point of Distributed Energy Resources Connection (PoC): The point where a DER unit is electrically connected in a Local EPS and meets the requirement of the MN DER TIIR and this document exclusive of any load present in the respective part of the Local EPS.

Reference Point of Applicability (RPA): The location where the interconnection and interoperability performance requirements are specified in the MN DER TIIR and this document applies. The RPA could be at the PCC or the PoC, or another location which is defined in the operating section of the interconnection agreement.

3. Performance Category Assignment

The city of Saint Peter has no further requirements for performance categories than that provided in the MN DER TIIR.

3.1. Normal – Category A and B

The city of Saint Peter follows the MN DER TIIR for category assignment.

Inverter-based DER Category B

Synchronous machine generation Category A

3.2. Assignment of Abnormal Performance Category I, II or III

The city of Saint Peter follows the MN DER TIIR for abnormal performance categories.

DER systems which can meet some or all the abnormal performance categories of IEEE 1547-2018 are encouraged to utilize Category I for all synchronous machine DER and Category II for all inverter based DER system(s).

4. Reactive Power Capability and Voltage/Power Control Performance

The DER shall be capable of maintaining a power factor level to help mitigate the impact of the DER energy export on the grid. This section provides the default and expected capabilities of a DER system on the Area EPS system. The IEEE 1547- 2003 setting profile should be used with the power factor setting adjusted to meet this section. Unless such operation is reviewed and approved by the Area EPS Operator, the DER shall not actively regulate the voltage at the PCC while in parallel with the Area EPS.

4.1. Constant Power Factor Control

The voltage and reactive power control for a DER system will greatly depend on the size and location of the DER within the Area EPS. The Area EPS Operator expects that the DER system shall maintain a constant PF at the RPA, per the operating section of the City of Saint Peter DIA. The DER Operator's default settings for power factor control shall be as follows:

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

*It is preferred that DER systems are capable of being adjusted within the range of 0.95 to 1.0 PF, but not required at this time. During normal operation of the DER system the power factor shall never be below 0.90 at the RPA.

4.2. Voltage and Active Power Control

City of Saint Peter requires the settings for Voltage and Active power control to be disabled, unless equipment that supports this function is utilized and there is a unique need and mutual agreement between City of Saint Peter and the DER Operator.

4.3. Voltage and Reactive Power Control

City of Saint Peter requires the settings for Volt-Var power control to be disabled, unless equipment that supports this function is utilized and there is a unique need and mutual agreement between City of Saint Peter and the DER Operator.

5. Response to Abnormal Conditions

Until equipment that is certified to meet IEEE 1547-2018 is readily available, it is required that equipment utilized for interconnecting and operating the DER system is certified to meet IEEE 1547a-2014. The IEEE 1547-2003 setting profile should be used with the power factor setting adjusted to meet section 4 of the TSM.

Settings are to be based on IEEE1547-2003 requirements for Voltage Ride-through and Tripping and for Frequency Ride- through and Tripping.

The city of Saint Peter does not currently allow dynamic voltage support by the DER system. See Section 4 for more information about dynamic voltage support.

6. Protection Requirements

The DER is required to at least have the protective devices that are shown in Appendix A one-lines. The protective devices are required for the safe and reliable operation of the Area EPS with interconnected DER systems. Only typical DER systems are shown in Appendix A and the one-lines do not fit all possible DER configurations. The specific protection requirements for interconnection will depend upon the DER's size and type; the number of units; Area EPS configuration and characteristics; the operating modes of the DER; and the location of the proposed DER interconnection on the City of Saint Peter system. The interconnection of a new DER to the Area EPS must not degrade any of the existing City of Saint Peter protection and control schemes nor lower the existing levels of safety and reliability to other customers.

If the DER system utilizes a transfer system, which transfers the members load from the Area EPS to the DER generation, and that transfer system has a user accessible selection of several transfer modes, the transfer mode which has the greatest protection requirements will establish the protection requirements for that transfer system.

The Interconnection Customer shall provide the required protective devices and systems to detect the voltage, frequency, current and possibly harmonic levels as defined in the IEEE 1547 standard during periods when the DER is operated in parallel with the Area EPS. The Interconnection Customer shall be responsible for the design, purchase, installation, and maintenance of these devices. Discussion on the requirements for these protective devices and systems follows:

6.1. Utility AC Disconnecting Device

A Utility AC Disconnect used by the Area EPS Operator and others, to safely isolate the DER, shall be supplied and installed by the DER Operator for DER generation.

1. Utility AC Disconnect – Requirements

The Utility AC Disconnect shall meet the following requirements:

- (1) Manually operated: able to be operated by one person and designed so that the operator is not exposed to energized components.
- (2) Gang-operated: One switch handle opens and closes all energized conductors simultaneously
- (3) Neutral conductor shall not be interrupted
- (4) Lockable in the open (off) position with City of Saint Peter padlocks
- (5) Readily accessible to utility personnel 24/7

- (6) Provides a visible verification that an air-gap separation exists between the blades and points of contact when open
- (7) Rated and listed for the application
- (8) AC rated device, located on the AC output/ utility side of any DER
- (9) No tools required to loosen or remove hardware or fasteners

The Utility AC Disconnect shall be located within 10 feet of the utility revenue meter. If it is not possible to locate the Utility AC Disconnect within 10 feet of the utility meter, written approval by City of Saint Peter for placement of the disconnect in a location which is not within 10 feet of the revenue meter is required. Also, if not located within 10 feet of the revenue meter, a permanently affixed placard meeting NEC requirements shall be located at the revenue meter, indicating the disconnect location. The placard shall achieve this with a mapped representation of the property, with the location of the disconnect denoted.

The Utility AC Disconnect may be the same disconnecting means required by the NEC (690.13, 705.20, or 706.15) if it meets all the other utility requirements (1-9).

A Utility AC Disconnect is not required for ESS which have a capacity of 1kWh or less or for ESS which are not capable of back feeding the Local or Area EPS, such as the case with an uninterruptible power supply (UPS).

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 the City of Saint Peter upstream protective device(s). All DER systems are required to have service protection furnished by the DER Operator immediately after the utility revenue main service meter.

1. Secondary Services

For DER installations, the preferred connection is through the existing service panel, sub panel or through a separate junction cabinet located on the service side of the utility revenue meter.

If the DER system cannot meet the preferred connection, approval will need to be obtained in writing from City of Saint Peter for the specific mode of interconnection.

2. Primary Services

The primary protective device(s) on the DER customer’s side of the revenue meter shall coordinate with the Area EPS Operator’s protective device(s) located upstream of the revenue meter (PCC). A coordination study must be completed and approved prior to energization.

3. Coordination with Automatic Reclosing Schemes

Most faults that occur on overhead lines are transient. That is, if the line is de-energized promptly, it can often be quickly reenergized and returned to service. Examples of such transient faults include momentary tree contact due to wind, and insulator flashover due to lightning. Automatic reclosing of overhead lines is a standard industry practice to improve system reliability. In many cases, an overhead line can be de-energized and reclosed within one second, with minimum disruption of service to the customers connected to the line.

The city of Saint Peter follows utility standard practices and operates most overhead circuits with reclosing enabled to improve reliability and reduce the number of sustained outages. Reclosing on Area EPS lines can potentially damage rotating machines, both synchronous and induction, that are operated in parallel with the EPS.

The DER Operator is responsible for protecting the DER facility's equipment so that automatic or manual reclosing, faults, or other disturbances on the City of Saint Peter system do not cause damage to their equipment. Addition of DER to a line shall not alter the Area EPS operators standard auto restoration schemes. Because of this, some configurations may require direct tripping of connected DER for faults on the Area EPS.

6.3. Protection Requirements

The following protection requirements are for grounded wye- wye DER system interconnections. Additional protection requirements may apply for systems which are not grounded wye or do not utilize a grounded wye-grounded wye transformer as part of the interconnection between the DER generation and the Area EPS. Please contact the City of Saint Peter to review and receive approval of the proposed protection configuration before ordering equipment or any field construction.

1. General Relay Information

For all DER systems utilizing certified inverter(s), 250kW and larger and other DER systems greater than 50kW, to be interconnected with the Area EPS, the protective functions and relay settings shall be reviewed, tested, and approved by a Professional Electrical Engineer, registered in the State of Minnesota.

For all DER systems larger than 40kW, which utilize inverters for the protective functions, the inverter settings shall be provided to City of Saint Peter for review and approval prior to final interconnection testing. For all systems utilizing protective relays, before energization or interconnection of the DER with the Area EPS, a copy of the proposed protective relay settings shall be supplied to the City of Saint Peter for review and approval. The review is to ensure proper coordination between the DER and the Area EPS. The documentation needs to be provided to City of Saint Peter with enough time to allow for review, coordination, implementation, and functional testing of the protective systems including time to implement any modifications requested by the Area EPS.

The coordination review is not a complete review of the DER protection, and it remains the responsibility of the DER Operator to ensure that there are adequate systems in place to protect the DER and the public.

Once the protective relay settings have been reviewed and approved by City of Saint

Peter, the DER Operator will complete a functional test of the protective relaying systems including injecting current and voltage into the relays and proving the associated protective breakers and switches will trip.

Use of inverters that are not in compliance with UL 1741 and certified by a nationally recognized testing laboratory (NRLT) shall not be permitted.

2. Relaying

All equipment providing relaying functions shall meet or exceed all applicable standards, including ANSI/IEEE Standards for protective relays, i.e., C37.90, C37.90.1 and C37.90.2.

Relays required to provide protective functions 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. Certified inverters which provide utility-required protective functions are excluded from this requirement if the aggregate Nameplate Rating of the DER system is 250kW or less.

Three phase interconnections shall utilize three phase power relays or multi-phase inverters approved by City of Saint Peter which monitors all three phases of voltage and current.

All relays shall be equipped with setting limit ranges at least as wide as specified in IEEE 1547. 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.

Non-exporting DER systems that operate in parallel with the City of Saint Peter system have the same requirements as that of any other DER interconnection.

Over-current relay (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. For example, the over-current relay monitoring the interconnection breaker shall operate fast enough for a fault on the customer’s equipment, so that no protective devices will operate on the Area EPS. 51V is a voltage restrained or controlled over- current relay and may be required to provide proper coordination with the Area EPS.

3. Protective Relaying Elements

3.1. Over-voltage relay (IEEE Device 59) shall operate to trip the DER per the requirements of IEEE 1547.

3.2. Under-voltage relay (IEEE Device 27) shall operate to trip the DER per the requirements of IEEE 1547.

3.3. Over-frequency relay (IEEE Device 81O) shall operate to trip the DER off-line per the requirements of IEEE 1547.

3.4. Under-frequency relay (IEEE Device 81U) shall operate to trip the DER off-line per the requirements of IEEE 1547. For DER with an aggregate nameplate greater than 30kW, the DER 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 the Area EPS is required for this setting.

3.5. The Area EPS will provide the reference frequency of 60 Hz. The DER control system must match this reference frequency. The DER protective relaying shall maintain the frequency of the output.

3.6. Reverse power relays (IEEE Device 32) (power flowing from the DER to the Area EPS) shall operate to trip the DER off-line for power flow back onto the system with a maximum time delay of 2.0 seconds.

3.7. Lockout relay (IEEE Device 86) requires a manual reset of the lockout before the device can be reclosed. Lockout relays shall automatically block the closing of breakers or transfer switches on to a de-energized Area EPS.

3.8. Transfer Trip – All DER shall disconnect from the Area EPS when the Local EPS is disconnected from its source to avoid unintentional islanding. DER that remains in parallel with the Area EPS may require a transfer trip system to sense the loss of the Area EPS source. The size and type of the DER and the capacity or minimum loading on the feeder will determine the need for transfer trip installation. The Area EPS System Impact Study will identify the specific requirements.

3.9. If the Area EPS is capable of sectionalizing, then more than one transfer trip system may be required. The System Impact Study will identify the need for a transfer trip system.

3.10. Parallel limit timing relay (IEEE Device 62PL) shall be set at a maximum of 120 seconds for Soft Loading Limited Parallel installations and no longer than 500ms for Closed Transition installations. Power for the 62 PL relay must be independent of the transfer switch control power.

4. Power for Protective Devices

All protective relays which require external power to operate must be supplied by a DC battery system that can maintain power to the protective devices for a minimum of 8 hours during a complete power outage. The DC system shall include a charging system with an alarming for failure of the charger. The battery system shall be equipped with a DC-undervoltage detection alarm or be monitored by a 24/7 monitoring facility. In the event of a failure of the DC power supply the protection scheme will be considered failed and the DER(s) associated with the protective schemes shall be quickly and automatically disconnected from the City of Saint Peter system. The DER system shall also be blocked from reconnection with the City of Saint Peter system until the DC power to the protective relaying system is reenergized.

For DER larger than 250kW an analog signal, or digital value representative of the real-time

DC voltage level must be provided to the Area EPS's monitoring system. For systems with an aggregated Nameplate Rating of less than 250kW, if the DC voltage level is not monitored 24/7 there shall be an alarming sound or flashing light upon loss of DC battery voltage.

Periodic testing and inspection, per the manufacturer recommendations of the DC power system, including the batteries and charger, is the responsibility of the DER Operator.

5. Open Phase Protection

5.1. For non-inverter-based DER, or inverter- based DER that opt not to use the onboard protective functions of the inverter for open-phase detection, either due to DER design configurations that render the detection method invalid or for other reasons, 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 zigzag or grounded wye-delta grounding banks
- Configurations with delta windings on step- up transformers.

5.2. As required by IEEE 1547, all DER must detect open phase conditions at their RPA 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.

6.5.3.3 City of Saint Peter 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.

- Positive-sequence phase balance and zero- sequence detection must set their pickup levels above the inherent 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.
- Loss of phase via under-voltage relaying detection is inadequate for identifying an open phase condition. Ground banks and delta winding, present on both the DER site and on the larger Area EPS, may reconstruct voltage at the open point of the RPA.

6. Single-phase DER on Multiphase Services

6.1. The total Nameplate Rating for an individual single-phase inverter on a multi-phase system cannot exceed 10% of the distribution transformer rating that is supplying the service.

6.2. Multiple single-phase DER systems which are connecting to a multi-phase service to form a three-phase generation source, must provide protection to allowing sensing and tripping of the DER generation upon the loss of a single individual phase on the Area EPS, with or without a fault.

6.3. DER systems which are connecting to an existing two-phase Open Delta- Wye or Open Wye-Delta secondary must be single phase and cannot be larger than 57.5% of the kVA size of the smallest utility transformer supplying the service or the service shall be converted to a three phase 120/208- or 277/480-volt service three phase service.

6.4. Grounding

All DER systems must be effectively grounded and meet the grounding requirements of the NEC. Larger commercial DER systems, especially systems with Nameplate Ratings greater than 1 MW, must be effectively grounded pursuant to IEEE std. 142 – IEEE Recommend Practice for Grounding of Industrial and Commercial Power Systems. For these larger commercial systems, the City of Saint Peter reserves the right at any time to request a report confirming effective grounding. In addition, any studies required to ensure that ground potential rise meets step and touch potential must also be submitted together to City of Saint Peter with the effective grounding report if requested.

1. Requirement of Grounding Transformers

Grounding transformers may be required for DER systems with an aggregate Nameplate Rating of 250kW or greater. During the application review process City of Saint Peter will work with the applicant to determine if a grounding transformer is required.

2. Wye-Wye Interconnections

For Wye-Wye transformer configurations both the primary and secondary side of the transformer shall be grounded. The DER must also have an appropriately sized ground bank or the generator's neutral must be adequately grounded.

3. Wye-Delta Interconnections

For Wye-Delta transformer configurations with the Delta on the DER side, the Wye side is required to be grounded. The Area EPS Operator requires high side voltage monitoring to sense loss of phase on the primary side of the transformer. The Interconnection Customer shall also plan to address zero sequence injection into the Area EPS from the grounded wye winding.

7. Additional Protection Requirements based upon Interconnection Transformer Configuration

The impedance of a dedicated transformer limits fault currents on the DER facilities from the Area EPS and limit's fault current on the Area EPS from the DER. Hence, it reduces the potential damage to both parties due to faults. It also reduces the ability for one party to identify faults on the other parties' system. As such a high-side and low side, fault-interrupting device is required for transformer protection. A three-phase circuit breaker is recommended, but fuses may be acceptable for DER systems rated less than 1,000 kW, provided coordination, if required, can be obtained with the existing Area EPS protection equipment. If fuses are used, it is recommended that the DER Operator install single-phase protection for its equipment.

Interconnection transformers are required to have an off- load manual tap changer on their primary (high voltage) side with a minimum range of +/- 2.5% of rated voltage.

7.1. Wye-Wye Transformer Connections

Both the primary and secondary of the transformer must be grounded. With this transformer connection the DER is subject to harmonics from the Area EPS and the DER must be designed to limit the harmonic output from the DER system to below the IEEE standard levels.

7.2. Open Wye & Open Delta Transformer Connections

No new services utilizing Open-Delta transformer connections are allowed on the City of Saint Peter system. Adding DER to existing Open Wye or Open Delta services will require special coordination with the Area EPS. Due to the nature of the transformer configuration, there will be significant limitations for adding DER to these types of transformation.

7.3. Wye-Delta Transformation

Wye side of the transformation is required to be grounded. High side phase voltage monitoring to sense single phase faults on the primary side of the transformer is also required. Potential issues due to zero sequence injections into the Area EPS from the Grounded Wye winding shall be addressed as part of the interconnection design. Design and detailed transformer documentation are required to be provided to the Area EPS Operator for review and approval, to ensure safe and reliable interconnection and overall operation. Ground source issues for the DER connected to the transformer delta side also need to be addressed.

7.4. Delta-Wye or Delta-Delta Transformation

These transformer configurations do not allow interconnection of a DER to the City of Saint Peter system.

7. Operations

7.1. Periodical Testing & Record Keeping

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 re- verification, the DER Operator shall notify the City of Saint Peter interconnection coordinator* and providing information about the proposed modification and contact information for whom City of Saint Peter should interact with about the proposed modification. Any of the above events may be cause for requiring re-verification of the interconnection and interoperability requirements as stated in TIIR Section 14.5. Since significant equipment damage and liability can result from failures of the DER protective equipment, the DER Operator must

ensure that all the DER protective equipment is operating properly. Thus, all interconnection-related protection and control systems shall be periodically tested and maintained, by the DER Operator, at a minimum, at intervals specified by the manufacturer or system integrator and this period shall not exceed 10 years. Periodic test reports and a log of inspections shall be maintained by the DER Operator and made available to City of Saint Peter upon request. The city of Saint Peter 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.

- The city of Saint Peter requires that any system that depends upon a battery for trip/protection power shall be monitored and inspected once per month for proper voltage. Logging of this periodic inspection is recommended. For systems with a nameplate rating of 250kW or more, 24/7 monitoring of the DC battery voltage is required.

7.2. O&M Agreements

For DER systems which utilize the City of Saint Peter document for the interconnection of the DER with the City of Saint Peter system, the operational and maintenance requirements are documented in Attachment 5 of that interconnection agreement. Section 5, the operating agreement, covers items that are necessary for the reliable operation of the Local and Area EPS and may be unique to each DER installation. The following are some of the possible items which may be included as operating requirements: (TIIR Section 15)

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 are not 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

7.3. System Voltage

Operation of the DER shall not cause the voltage at the PCC to go outside of ANSI Range A levels under normal conditions. The operation of the DER system must also not adversely affect the City of Saint Peter distribution system voltage balance among the phases and must be able to operate under the existing feeder voltage imbalanced conditions. Operation of the DER that causes voltages issues may be cause for disconnection until the reason can be identified and corrected.

Any sudden voltage changes caused by the DER which adversely affect other customers supplied by the Area EPS shall not be allowed. It is the DER Operator's responsibility to resolve adverse voltage changes caused by the operation of their DER. The City of Saint Peter will work with the DER Operator to identify possible solutions.

7.4. Power Ramp Rates

1. Overview

The ability for the Area EPS to response to large changes in increasing or decreasing demand for energy depends upon the location of where the DER is interconnected with the Area EPS. Step changes in load or energy production affect the voltage levels due to the rapid change. Also, if the step increase in current is large enough, it could be mistaken for a fault by protective devices and result in an outage. The larger the step change in load or generation the greater the chance of creating operational problems for other customers on the City of Saint Peter system.

As part of the interconnection study, City of Saint Peter will review the potential for step changes in load or energy production to create operational problems on the Area EPS. City of Saint Peter's review does not consider potential Local EPS issues which may result from block changes in load or generation from the DER, this is the responsibility of the DER Operator.

2. Requirements

City of Saint Peter will review the proposed DER to see if any power quality issues would be expected from the interconnection and operation of the proposed DER. City of Saint Peter uses a limit of a 2.5% voltage step change for a step change in DER output.

DER systems shall not cause the Area EPS voltage to go outside of the ANSI range A voltage levels. This is during normal operation and during times when the DER generation is entering or leaving service. Block loading or off-loading of the DER generation that cause voltage step changes of 2.5% or more on the Area EPS are not allowed. The operation section of the City of Saint Peter DIA will document unique operational requirements for the DER.

7.5. Enter Service

Each time a DER is starting operation is referred to as Enter Service. The method a DER uses to Enter Service is important for the reliability and performance of the Local EPS and the Area EPS. Enter Service could be after a power outage or as part of the daily normal operation of the DER.

Upon restoration of the Area EPS, after a prolonged outage, many appliances will automatically restart and place a heavy demand upon the Area EPS for energy. Because of this Energy Storage Systems are asked to delay their recharging of the ESS for a period to allow the increased demands from the other appliances to first be satisfied. All DER shall delay reconnection to the City of Saint Peter system for at least 5 minutes after normal voltage and frequency is restored, per IEEE 1547.

Any limitations on the way the DER system enters service will be documented in the operating section of the interconnection agreement.

1. Non-Energy Storage Systems

The following are some possible methods which may be required to be used:

i. The delay time for restarting of the DER after an outage may be increased.

ii. The DER shall stagger the restarting of inverters under normal restarting and after an outage (maximum step amount of staggering required will be defined)

iii. Multiple transfer switches may be required for block loading DER to break up the blocks of load transferred to the DER

2. ESS – see ESS section

ESS systems can affect the Area EPS through large step changes in recharging the ESS or through block load transfers from/to the Area EPS and the ESS. See the ESS Section for the Enter Service requirements. The operation section of the City of Saint Peter DIA will document the operational requirements for the DER. The following are some possible methods which may be required to be used:

i. The delay time for restarting of the DER after an outage may be increased.

ii. The charging of the ESS may require a predefined ramp rate.

iii. The discharging 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.

1. DER Limiting Power Control System Requirements

The Power Control system must be NRTL certified and meet the following requirements:

- (1) For Power Control systems which are installed to control export to the Area EPS, it shall be 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 lesser of 100kW or 10% of the DER Nameplate Rating. Or, if the Power Control system is being used to limit the DER capacity, the Power Control system, shall be able to halt or reduce energy production within two seconds after either the period of DER output across the PoC exceeds defined DER capacity level for 30 seconds or the level of inadvertent DER energy output is 100kW or 10% over the defined DER capacity level

- (2) Able to monitor the total energy flow across the PCC or PoC as applicable.

- (3) Able to self-monitor the operational status of 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) If the power to the Power Control system is not available the DER system must be blocked from operating in parallel with the Area EPS

2. Documentation

The following is a list of information which is to be provided to the City of Saint Peter as part of the application filing if the DER system relies on the Power Control system to regulate the output of the DER and/or limits the charging of the DER ESS. Generally, the Area EPS engineer will need enough information to understand how the Power Control system will operate; how it will be installed; what the intended function(s) of the Power Control system is; and how the monitoring will be accomplished.

- (1) Manufacturer and model of the Power Control system

- (2) NRLT certifications of the Power Control system

- (3) Electrical schematic of the Power Control system monitoring and control

- (4) Link to location of the user manual for the Power Control system

- (5) Maximum response time for the Power Control system to modify the output of the DER, in response to a large step change in the local electrical loads.

- (6) Description of the reason for the Power Control system and active 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 exporting across the PCC”

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

- (8) Other information which is useful to help the Area EPS engineer to understand the Power Control system installation and operation

3. Inadvertent Export

Inadvertent export is the unscheduled and uncompensated flow of real power, through the PCC and back into the Area EPS system. Inadvertent export may occur during sudden changes in electrical demand on the Local EPS and must be quickly resolved through the automatic adjustment of the DER output through the direction of the DERs Power Control system.

Inadvertent export, if it is large enough, could cause tripping of protective devices and a resulting 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 cumulative amount of inadvertent exported energy from the Local EPS to the Area EPS, across the PCC, in any billing month shall be less than the on-site aggregated DER Nameplate Rating(s) multiplied by one hour. 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.

Any amount of inadvertent export of real power across the PCC lasting longer than 30 seconds for any single event shall result in the disconnection of the DER system from the Area EPS within two (2) seconds of exceeding the 30-second duration limit.

9. Interoperability

All DER shall have provisions for a local DER interface capable of communicating to support the information exchange requirements specified in this manual for all applicable functions that are supported in the DER. The decision to use a local DER interface or to deploy a communication system shall be determined by the City of Saint Peter.

NOTE: Since the interaction of multiple DER systems can affect the Area EPS differently, installation with multiple DER systems on the same service may have different requirements than if interconnected individually. If the total aggregated nameplate rating of all DER interconnected on a single service is greater than 250kW, monitoring and control requirements may be different. Please contact City of Saint Peter for specific requirements.

For many DER systems, the City of Saint Peter may use a production meter to provide monitoring and visibility.

*City of Saint Peter may require Supervisory Control and Data Acquisition (SCADA) and monitoring capability for DER over 250 kW. System monitoring shall be provided to the appropriate control centers for the purpose of providing real-time remote monitoring and control of the generator/inverter. The communications medium shall provide reliable communications and not traverse the internet nor include a publicly available service. The communication system shall contain the appropriate firewall to allow only permitted exchange of information. Local and/or regional telecommunication companies may be leveraged to provide point-to-point services to the Area EPS control center(s).

9.1. Sales to Parties other than the Area EPS

For energy sales to parties other than City of Saint Peter, the metering and monitoring requirements are not defined. There are many possible power purchase requirements which may dictate the need for special metering and/or monitoring. Therefore, in these circumstances, if permitted, a separate City of Saint Peter DIA may be required.

9.2. Direct Transfer Trip

Unless designed to operate as an island, all DER systems are required to disconnect from City of Saint Peter when that portion of the City of Saint Peter system is disconnected from its source. This is required to avoid unintentional islanding of the Area EPS. This disconnection can be accomplished in several ways. For many inverter-based DER, a UL 1741 certification provides assurance that the DER will disconnect from the Area EPS upon loss of the Area EPS source. For non-certified systems, and in some scenarios where certification of systems may be inadequate, disconnection is triggered by a direct transfer trip signal from the Area EPS that trips a DER Operator owned device, such as a breaker or recloser. The need for transfer trip installation is dictated by the size and type of the DER in relation to minimum loading of the feeder and existing DER size and type. The system impact study will determine the specific requirements.

When a Direct Transfer Trip is required, the DER Operator shall make provisions for transfer trip. These provisions include:

1. Facilities to mount an antenna that provides direct line of sight with the City of Saint Peter substation the DER is interconnecting with.

2. A mounting location for a City of Saint Peter communication cabinet is required. DER Operator is required to provide AC power for this communication cabinet.

3. 24/7, unescorted, drivable access.

4. The customer shall make available two contacts for City of Saint Peter control wires. These contacts will be to:

(1) trip a breaker that disconnects the DER from the Area EPS,

(2) block the breaker from reclosing.

5. The entire direct transfer trip operation, including processing of signals and operation of the customer equipment in conjunction with the AREA EPS control signals, shall not exceed 2 seconds.

9.3. Level of Communications Required

1. When Required

A communication channel for the monitoring and control between the DER and City of Saint Peter is required once the DER is greater than 250kW in size or is on a tariff/rate that requires monitoring.

2. What's Required

When remote monitoring and control by the City of Saint Peter is required, the DER Operator is responsible for the cost to provide the communications to the Area EPS's Control Center. If the DER is smaller than 1,000 kW the DER Operator may provide and operate this communication. If the communication channel is provided by the DER Operator, the communication channel must be battery backed up so it can operate for a minimum of 8 hours during a power outage; meet required cyber security standards (see section 9.6); support a polling rate of once every 10 seconds; and utilize DNP3.0 protocol. The communication channel should be designed, installed, and operated to provide highly reliable (99.5% or better) communication with the City of Saint Peter. The design of the communication channel with the Area EPS must be reviewed and approved by the City of Saint Peter.

At the DER Operator's request, the City of Saint Peter will design and install a communication channel between the DER monitoring system and the Area EPS. The actual cost of this installation will be the responsibility of the DER Operator. The City of Saint Peter will provide a firm cost estimate, if requested by the DER Operator. Due to reliability concerns with cellular communication during emergencies, for DER installations 1,000 kW or more, City of Saint Peter requires that it designs, installs, and operates the communication channel. The installation cost is the responsibility of the DER Operator.

9.4. Level of Monitoring & Control Required

1. When Required

Remote monitoring and control of the DER system by the City of Saint Peter is required once the DER is greater than 250kW in size or on a tariff/rate that requires monitoring.

2. What's Required

The final list of parameters (points) required to be monitored and controlled by the City of Saint Peter system will be defined within the operational section of the interconnection agreement. Below are the typical points which will be required for a generic 1,000kW DER with remote monitoring and control required.

For DER systems which are smaller than 1,000kW, the DER Operator has the option of providing the monitoring and control system. The city of Saint Peter requires the use of (DNP3.0?) for communication between the DER system and City of Saint Peter. All equipment used to provide the monitoring for the City of Saint Peter must be reviewed and approved by the City of Saint Peter. The equipment must be battery backed up so it can operate for a minimum of (4 or 8?) hours during a power outage. The installation shall be designed, installed, and operated to provide highly reliable (99.5% or better) communication with the City of Saint Peter. For a failure of monitoring system supplied by the DER operator, the DER shall be disconnected and will remain disconnected until the monitoring failure has been resolved.

At the DER Operator's request, City of Saint Peter will design and install a SCADA control and monitoring system for the DER installation, to meet City of Saint Peter requirements. The actual cost of this installation will be the responsibility of the DER Operator. The City of Saint Peter will provide a firm cost estimate if requested by the DER Operator. For DER systems 1,000 kW or more, City of Saint Peter requires that it design, install, and operate the monitoring and control system. The cost of this system is the responsibility of the DER Operator.

For installations which qualify for rates/tariffs which require the monitoring and control, City of Sainte Peter will provide the SCADA monitoring and communication per the terms of the applicable rate/ tariff.

Example parameters (analog, status, and control).

Status Parameters

- 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 City of Saint Peter)

- Low voltage alarm (setting defined by City of Saint Peter)

- DC supply / charger trouble alarm

- Trouble alarm (relay failure alarm) from each protective relay providing the utility required protection elements.

- General Trouble Alarm, can be a common alarm or individual alarms, need to include generation control trouble, issues with DC voltage.

Control Parameters

- Remote control of interconnection breaker (open / close) hard wired from the Area EPS RTU directly to the breaker, not supervised by the breaker's relay. The reclose shall be supervised by the lockout relay.

- Ability to curtail output of DER to a specific level (0-100%). This functionality may allow the City of Saint Peter to keep the DER operating longer, instead of just opening the interconnection breaker when there are issues with the distribution system.
- Ability to start and stop DER and transfer load off the system. (If required by rate/tariff)

- Ability to remotely turn on/off modes of operation, and/or monitor which modes of operation are active (if applicable) Analog Parameters (Values updated at least every 30 seconds, every 10 seconds is recommended)

- Individual phase voltage values representative of the Area EPS's service to the facility

- Power quality values such as Total current harmonic distortion (Current THD), Total current demand distortion (TDD), and Total voltage harmonic distortion (Voltage THD)

- Individual Phase amps (DER output)

- DC voltage from protective DC battery

- 3 Phase Real (kW) and reactive (kVAR) power flow for each DER

9.5. Type of Interface Required

When monitoring and control is required the following interfaces are the typical methods of achieving the control and monitoring.

1. Interface with Inverters

For inverter-based systems an interface to the inverter or a central inverter controlling device is required. Many of the monitoring points and controls can be easily implemented via this integration.

2. **Hardwired Control**

The open / close control points for the remote operation of the interconnection breaker by City of Saint Peter are required to be directly wired to the breaker for the open control and directly wired through the lockout relay for the close control. This wiring shall not include any relaying or control devices, so that it can be used as an emergency disconnection by the City of Saint Peter in the case of a relay or control failure.

3. **Interfaces with Protective Relays and Control Systems**

The protective relays, DC systems and control systems shall provide self- monitored alarm contacts which alarm for issues with the devices.

9.6. Security

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. The selection or initiation of DER operating modes which have not been reviewed or approved by the City of Saint Peter shall be password protected and only accessible to qualified factory personnel.

Equipment which is connected to the City of Saint Peter’s monitoring and control shall be protected by physical locks and only accessible by qualified personnel.

2. **Network Security**

It is the DER Operator’s responsibility to ensure cyber security of the DER system. The DER Operator is responsible for ensuring that cyber security vulnerabilities in the DER Operator’s systems are quickly resolved or mitigated when they are identified. Security of cyber access to the DER Operator’s equipment and to DER communication equipment is the responsibility of the DER Operator and shall be designed to only allow cyber access for authorized personnel.

Any communication links between on-site pieces of DER equipment and City of Saint Peter equipment shall be a direct link and not use a shared communication channel with any other communication. Encryption is not required for links which are between equipment which is entirely on- site and physically secured.

3. **Network Encryption Requirement**

Any communication link supplied by the DER Operator, between the DER system and an off-site City of Saint Peter system shall be a direct link, not a shared communication channel with any other communication and shall be encrypted to the City of Saint Peter encryption standards. The city of Saint Peter requires the encryption to follow the most recent NIST standards including SP 800-175B. (How is this documented at the utility?) The City of Saint Peter reserves the right to periodically perform a cybersecurity audit on the DER’s communication interface with City of Saint Peter. The

DER Operator shall provide scheduled access for the City of Saint Peter to complete this audit.

10. Energy Storage Systems (ESS)

10.1. General

Energy Storage Systems are subject to witness testing in the same manner as other DER systems. The city of Saint Peter will require the testing of the interconnected ESS along with any other DER installed at the location. The addition of an ESS to an existing DER installation may necessitate the retesting of the aggregate DER system.

10.2. Defining Common Modes of Operations

The following defines a set of common operational modes for Energy Storage Systems (ESS). Each manufacturer uses different terms for their modes of operation. If the following terms do not match with the operating mode(s) of your system, please provide information fully explaining the operating mode.

One or more of the operating modes for the ESS must be listed in the DER interconnection application. The process used to review the ESS interconnection application will depend upon the modes that have been identified for review. If the ESS has the capability of operating in more than one operating mode, then all the operating modes available to the DER Operator must be listed on the interconnection application. Operating modes which are blocked from being selected by the DER Operator do not need to be listed on the application.

It is helpful for the application review process that the information provided on the interconnection application for the ESS, City of Saint Peter MIP and any additional supporting documents attached to the application, address the following questions about the ESS operational characteristics.

- If the ESS is not designed to export power back into the Area EPS, how is the physical configuration and/or control system designed to ensure that power is not exported?

- For failure of the ESS control system or failure of an automatic isolation switch what will stop the ESS from exporting to the Area EPS?

- How can operational control modes be changed?

- Are all operational modes available to be changed / used by the end user?

- If some operational modes are not available to the end user, how are they locked out?

- The use of ESS is rapidly evolving, so this section has been written to provide the information for the expected ESS use cases. The following operating modes are the expected standard modes, but DER/ESS systems may be designed for different operating modes than are listed here, please contact the City of Saint Peter DER Interconnection Coordinator to discuss any unique operating modes.

1. Backup Power

This operating mode is designed so the ESS is only providing energy to the Local EPS during a power outage or during storms and other periods requiring high reliability and will not be providing energy to the Local EPS at other times. Selecting this mode requires the interconnection with the Area EPS is disconnected when supplying energy to the Local EPS. The ESS is normally sitting fully charged, waiting for an event such as 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 demand on the Area EPS and the local service. This would create higher rates and could overload the Area EPS. To help eliminate this risk, the ESS is requested to delay the recharging of the ESS for 15-30 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.

2. Demand Charge Reduction

ESS is used to reduce the peak demand of the Local EPS. This can be referred to as demand management, 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 for step load changes in the Local EPS.

The charging of the ESS is typically limited to periods when the Local EPS loads are minimal, so as not to cause a higher demand.

3. Increased PV Self-Consumption

ESS is used to store energy during periods of excess DER output, for use by the Local Area EPS during other times.

4. Time-of-Use Bill Management

The ESS is used to store energy during times when low-cost power (off- peak) is available and then releases energy to support on-site consumption during periods when the costs of power is greater (on-peak).

5. DER System Support

ESS is used to dampen voltage swings due to Solar / wind variable output, and/or utilizing the ESS to reduce utility demand charges by filling in dips in variable renewable energy production.

6. Grid Services

The requirements and distribution energy tariffs for distribution connected Energy Storage Systems to provide grid support functions have not yet been developed. At this time use of ESS interconnected with the City of Saint Peter distribution system to provide grid services is not permitted.

10.3. Control System Requirements

1. 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 and frequency, 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 also preferable to have the ESS control system ramp up the recharging level from 0-100% over a 5-minute period upon entering service.

2. 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 City of Saint Peter cannot be utilized. The ability for the homeowner, business owner or employee of the business to turn on additional unreviewed and unapproved modes shall be strictly controlled. Only qualified service personnel shall have access to turning on additional modes of operation after review and approval of those new operating modes by City of Saint Peter.

11. Metering Requirements

Depending upon the type of DER, the applicable tariffs, the method of interconnection and the size of the DER, different metering requirements apply. In general, the DER Operator is responsible for providing and installing the meter socket and the City of Saint Peter will provide and install the meter. The DER Operator must allow City of Saint Peter access to the DER system to inspect and ensure revenue metering and monitoring is accurate.

11.1. Factors Affecting Metering Requirements

The following is an educational discussion on the different factors which affect the type of metering required for the interconnection of a DER system. Section 8 of the TIIR provides a general scope of the reasons for the development of metering requirements.

- *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.*

- *Planning – an archive of time-series information over multiple years of DER operation is required for Area EPS, BPS and TPS planning.*

- *Regulatory – The Area EPS Operator may have obligations to track and report on the amount of energy produced from renewable energy DER. Specific incentive programs or tariffs can create additional metering needs.*

- *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.*

1. Net Metered Interconnection

The city of Saint Peter is required to net-meter PURPA qualified DER that has an aggregate Nameplate Rating of less than 40kW and interconnected with the distribution system. Net metering allows the customer's DER to generate excess energy, greater than the local load requirements and push that energy back into the Area EPS. The city of Saint Peter will purchase excess energy from the customer under the current rate schedule.

Net metering requires the separate measurement of energy flow, both into and out of the electrical service. To support this type of interconnection, the main service meter will/may be replaced or reprogrammed to measure and record energy flow in both directions.

2. Utility Incentive Program

To qualify for a City of Saint Peter solar incentive program, a meter to measure and record the production of the solar system may be required. (This information is separate from this TSM)

3. Third Party Power Purchases

If allowed by the Area EPS, a third party may be purchasing the output of the generation. The metering requirements will be dependent upon many factors, including the party purchasing the output and the requirements of the power purchase agreement. The TSM does not directly address the requirements for all types of installations where there are energy sales to parties other than to the City of Saint Peter. Contact the City of Saint Peter DER interconnection coordinator to discuss any DER that is considering third-party purchase of the energy from the DER.

Depending upon the power purchase agreements or applicable rates/tariffs, real-time communication with the meters may be required. If communication is required, the DER Operator is responsible for all costs to implement and maintain the required communication.

4. Standby Service

For DER systems which have a nameplate rating of 40 kW or larger standby rates/tariffs may apply. Contact the City of Saint Peter for appropriate schedules and rates.

5. Metering when Installing Multiple Types of DER

How the DER is connected and operated may affect the method of metering for specific rates/tariffs. Also, when multiple types of DER are installed on the same electrical service, interaction between different rate/tariff requirements may affect the metering requirements. Another factor which may affect the installation are the operating mode(s) of the DER. This is especially true for Energy Storage Systems (ESS). The operating mode(s) of the ESS will affect the placement and type of metering and possibly could affect which tariffs are applicable. See Energy Storage Section of the TSM for information about metering requirements for DER systems which include Energy Storage.

11.2. General Requirements

Depending on the specific service, type of interconnection and type and size of DER system, the metering requirements may vary. The installation of the meter shall follow the City of Saint Peter metering installation requirements. Some of the basic requirements include.

1. All meter sockets must be bypassing type sockets, with a manually operated lever bypass.

2. All metering for a single service must be grouped within a 10 feet area.

3. The center of the meter socket shall normally be mounted at a height between 4 to 6 feet above the ground, to allow safe reading of the meter.

4. Meters must be protected from damage.

11.3. Meter Location and Accessibility Requirements

All metering shall be accessible by City of Saint Peter crews 24/7/365 with an open walkway to the meters, that is clear of shrubs, bushes, etc. The meter shall not be behind a locked fence or door unless there is a written agreement between the Customer and City of Saint Peter.

11.4. Main Meter (PCC)

The Area EPS's Point of Common Coupling (PCC) meter is owned and maintained by the Area EPS. For an existing building, this is the existing main service meter. The city of Saint Peter supplies the main meter and for larger commercial services any necessary voltage transformers (VT) and current transformers (CT). The Interconnection Customer is required to provide and install the meter socket that meets the City of Saint Peter metering requirements.

11.5. Production Meter (PoC)

The City of Saint Peter currently does not require the installation of a production meter. The City of Saint Peter reserves the right to change this requirement at any time without notice. If the City of Saint Peter requires the installation of a production meter in the future, the information and requirements in Sections 11.5, 11.5.1, and 11.5.2 will apply.

The city of Saint Peter may use production meters to help reduce or eliminate future costs to the customer for a communication channel with smaller DER installations. The production meter is typically installed at the PoC. For most single-phase DER systems, the production meter supplied by City of Saint Peter may have an internal switch which can be remotely operated by City of Saint Peter to control the output of the DER. While the need to use this meter switch will be very limited; this switch is available to remotely interrupt the output of the DER during system emergencies in support of the operation of the distribution system and help speed up restoration of service during storms.

The production meter may allow for the historical recording of the DER output. This data is made available to the customer so that they can identify operational issues with the DER output levels. The data may also be used by City of Saint Peter engineers to ensure the distribution system is adequately sized to meet the electrical needs of the customers. Aggregated metering data may also be shared with the transmission provider to help with the operation of the bulk power system.

1. Production Meter Required for Extended Parallel

Unless exempted in section 11.5.2, a production meter is required to be installed to measure the output of DER that operates in extended parallel with the Area EPS Operators distribution system. The DER Operator is responsible for installing a meter socket with a bypass lever and the City of Saint Peter will provide, install, and operate the production meter.

2. Production Meter Not Required

A production meter is not required if the DER does not operate in parallel with the Area EPS and is designed to operate and temporally carry the Customer's load disconnected from the Area EPS. An example of this is a DER that is connected to supply the load, during power outages, peak load periods, etc. using a physical transfer switch. A production meter is not required even if the transfer switch momentarily parallels the DER with the Area EPS.

A production meter is also not required for Energy Storage Systems, installed alone, if the ESS is smaller than 250kW and designed to not export to the Area EPS. A production meter is required if other DER systems, such as a solar generator is installed along with the ESS. In this case, the production meter must be installed to measure only the solar system energy output, unless otherwise approved by City of Saint Peter.

12. Signage and Labeling

12.1. General

All signage and labeling shall meet the applicable NEC requirements including NEC 110.21 (B), 690.13 (B) and 705.10

12.2. Utility AC Disconnect

Required labeling shall meet the same characteristics as listed in NEC. The Utility AC Disconnect shall be labeled as “Utility AC DISCONNECT”

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

12.3. Main Meter

If the Utility AC Disconnect has been approved by the City of Saint Peter to not be located at the same location as the main service meter, then a sign at the main service entrance meter shall be installed to indicate that the location contains DER(s). Each type of DER present shall be listed (i.e., PV, Wind, ESS, Gas Generator). The sign shall provide clear direction to the distance and location of all Utility AC Disconnects. The preferred sign shall be a site map of the area with an X for the main service entrance meter location and an O for the Utility AC Disconnect location. 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”. In cases where multiple production meters exist on the load side of the main meter, each production meter shall be labeled as such to identify which DER unit is being metered.

13. Test and Verification Requirements

13.1. Procedure

For DER systems which are larger than 40kW or not utilizing a certified inverter the Interconnection Customer shall provide a testing procedure to the Area EPS Operator prior to the scheduled inspection and testing of the DER system. City of Saint Peter can provide examples of testing procedures for the specific type of DER interconnection. The criteria to be included in the testing procedures are listed in Section 13.2 and Section 13.3.

For DER systems which are 40kW or smaller and utilizing a certified inverter for interconnection the simplified process testing procedure outlined in the TIIR will be followed. The general process that City of Saint Peter will use for the final test and inspection for simplified systems is outlined in the TIIR and is as follows:

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)

13.2. Pre-Interconnection Commissioning Testing

The following inspections and testing are required to be completed by the DER Operator prior to the Area EPS representative arriving onsite for interconnection testing.

1. **Grounding**

   Grounding shall be verified to ensure that it complies with the TIIR, TSM, NESC and the NEC requirements.

2. **CTs & PTs**

   If applicable, current transformers (CTs) and Voltage Transformers (VTs) used for monitoring and protection shall be tested to ensure correct polarity, ratio, and wiring.

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

3. **Breakers**

   If applicable, verify that the breaker or switch cannot be operated with interlocks in place or the breaker or switch cannot be automatically operated when in manual mode.

4. **Relays**

If applicable, all protective relays shall be calibrated and functionally tested to ensure the correct operations of the protective element. Prior to this point in the process, the City of Saint Peter should have received relay settings for all utility-required protective relaying and have completed the utility coordination review and approval. 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. Lockout relays shall be tested to prove that when tripped the ability to reclose the associated breaker or switch is blocked.

5. **Remote Control**

If applicable, all required remote-control functions and remote monitoring points shall be verified operational. In some cases, it may not be possible to verify all the analog values prior to energization. Where appropriate, those points may be verified during the energization process.

6. **Phase Tests**

For multi-phase DER systems, phase tests shall be completed to ensure proper phase rotation of the generation and wiring. If requested, City of Saint Peter may be able to acquire the equipment and personnel to help with completing the phase testing to ensure proper phase rotation and may require testing prior to the final interconnection tests.

7. **Synchronizing Tests**

For non-inverter connected DER systems, synchronizing test shall be done across an open switch or racked out breaker. The switch or breaker shall be in a position that is incapable of closing between the DER and the City of Saint Peter system 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. This test shall also demonstrate that if any of the parameters are outside of the ranges stated, the paralleling-device shall not close. For inverter-based interconnected systems this test may not be required unless the inverter creates fundamental voltages before the paralleling device is closed.

8. **Final System Sign-off**

To ensure the safety of the public, all DER systems which do not utilize a certified inverter for interconnection shall be certified as ready to operate by a professional Electrical Engineer, registered in the State of Minnesota, prior to the DER system being considered ready for onsite testing.

13.3. Final Interconnection Commissioning Testing

The following tests will proceed once the DER system has completed pre- interconnection commissioning testing and the results have been reviewed and approved by the Area

EPS Operator. For simplified certified inverter based DER systems the Area EPS has attached to this TSM in Appendix C, a standard interconnection test which will be performed. On larger and more complex DER systems the Interconnection Customer and the Area EPS Operator will coordinate with the development of the required testing procedure. All final interconnection commissioning tests shall be based on written test procedures agreed to between the Area EPS Operator and the Interconnection Customer.

1. Verification

Upon arriving on site City of Saint Peter personal will.

- Verify 24/7 unescorted access is available to City of Saint Peter personnel.

- Verify that the equipment listed on the application and the nameplates of the equipment used are the same.

- Verify the installation matches the one-line provided by the DER Operator

- Verify that all required labeling meets TSM section 12 requirements.

- Spot check the settings of the protective relays, inverters, and control systems, to verify that they match the information provided by the DER Operator

- Complete final testing of any remote control and/or remote monitoring which could not be performed prior to this final testing.

2. Anti-islanding

For systems which operate in parallel with the Area EPS the following testing will be required to test the anti-islanding functions of the DER.

i. The DER system shall be started and connected in parallel with the Area EPS source. It is recommended that this test be completed when the DER can produce at least 15% of the rated output for this test.

ii. The Area EPS source shall then be removed by opening a switch, breaker etc.

  o For multi-phase systems this test will include separate tests with an opening of all phases and opening of each individual phase, one at a time.

iii. The DER generation shall either separate from the Area EPS together with the local load or stop generating.

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

v. If the interconnection agreement specifies enter service requirements, then these will be verified at this point in the process, as part of the restarting of the DER

3. 62PL Relay

For transfer switches which require a 62PL relay to limit the amount of time the DER is operating in parallel with the Area EPS, it is important that the following is confirmed before final testing of the installation is started.

i. The 62PL relay must be a separate relay and not part of the DER control PLC or the transfer switch PLC.

ii. The 62PL actuation shall be wired in series with the closed position of both transfer switches (Utility and Generator). So that when both switches are closed the 62PL timer is started.

iii. The 62PL relay shall be wired to isolate the DER from the Area EPS by tripping a breaker.

(DER generator breaker preferred). Tripping of a transfer switch solenoid does not meet the requirement, as the solenoid actuator may be what has failed.

4. Control Modes

For DER systems which utilize inverter settings, a PLC or other type of Power Control system to limit the output of the DER to a control level, the testing of the overall Power Control system shall be performed as part of the final interconnection commissioning test. The testing procedure shall be developed to confirm the ability of the Power Control system to limit unintended DER output levels, including the ability to quickly resolve inadvertent exporting.

5. Confirm Phasing

For multi-phase DER systems, the phasing between the DER and the Area EPS shall be confirmed before the DER is interconnected with the Area EPS. City of Peter requires to be present when the testing is performed to witness. Confirmation of the correct phase connections and phase rotation shall be by testing the phase voltages across an open point between the DER generation and the Area EPS.

6. SCADA and Communications

For DER systems which require SCADA or other communication with City of Peter system, if not completed before the final on-site testing, each of SCADA points shall be tested to confirm correct data and intended operation. It is most efficient to have any communication and SCADA points tested before the final testing.

7. **Enter Service**

Testing of the ability of the DER to meet any Enter Service requirements shall be part of the final testing process.

13.4. Documentation

The Interconnection customer shall provide a written test report to the Area EPS Operator within 10 days of the testing and verification of the DER. The documentation shall include the following as applicable. For simplified inverter-based DER, completion of the testing procedure in Appendix C will serve as the final documentation of the DER interconnection.

1. **Grounding**

Documentation required:
- Grounding equipment nameplate drawing.
- Ground referencing calculations.
- Drawing of ground referencing equipment protection schemes.
- Written verification that grounding equipment meets NEC and NESC.

2. **Potential and Current Transformers**

Documentation required:
- Written verification that the correct PTs and CTs are installed.
- Written verification that the CT’s shorts and ground have been removed when applicable.
- Details on main site protection.

3. **Breakers and Switches**

Documentation required:
- Written verification that all breakers, switches, and associated controls function properly.

4. **Relays**

Documentation required:

- Copy of as left protection settings (relay(s) and/or inverter(s))

Signed verification of relay calibration and testing.

5. **Fault Current**

Documentation required:
- If not already provided during the application or study process, fault current characterization information required in IEEE 1547, subclause 11.4 shall be provided. This is required for synchronous and induction generation and electronically coupled DER with the aggregated rated capacity of 500 kVA or larger.

13.5. Failure Protocol

If the DER system fails testing and verification, the Interconnection Customer shall correct outstanding issues and provide updated documentation to Area EPS Operator on the changes made. The Interconnection Customer shall schedule a testing and verification date with the Area EPS Operator. If necessary, a revised testing procedure shall be provided to the Area EPS Operator.

13.6. Hardware or Software Changes

Whenever interconnection system hardware, software or firmware is changed there can be an effect on the equipment and functions listed below. Re-commissioning of equipment is required for all hardware changes impacting the interconnection listed as follows:

- Switchgear and conductors
- Protective relays
- RTUs and sensors
- Communication devices
- Inverters

A re-test shall be required of all potentially affected functions including but not limited to the following:

- Over voltage and under voltage
- Over frequency and under frequency
- Fault Detection
- Inability to energize a de-energized line
- Time-delay restart after EPC Distribution System outage
- Reverse or minimum power function (if applicable)
- Synchronizing controls (if applicable)
- Anti-islanding functions (if applicable)

14. Sample Documents for Simplified Process

14.1. On-line Diagram

The following is a sample one-line diagram for basic DER interconnection. The more information you can provide on the one-line the better the City of Saint Peter is able to understand what is proposed to be installed and this improves our ability to review the installation. Please note that for DER installations which require a production meter the DER is wired to the LOAD side of the production meter.

The information required on the one-line diagram includes:

o Name of the Customer located at the electrical service where the DER is proposed to interconnect

o The connectivity of all equipment between the utility PCC and the proposed DER, including, switches, breakers, fuses, junction boxes, combiner boxes, protection devices, etc.

- Utility AC Disconnect (visible gap)

- Main Service meter and if required the production meter

o Aggregate nameplate rated AC kW capacity of each DER system

o AC voltage of the system

o Number of phase (Single or Three phase)

o Diagram any control system wiring or communication between the elements.

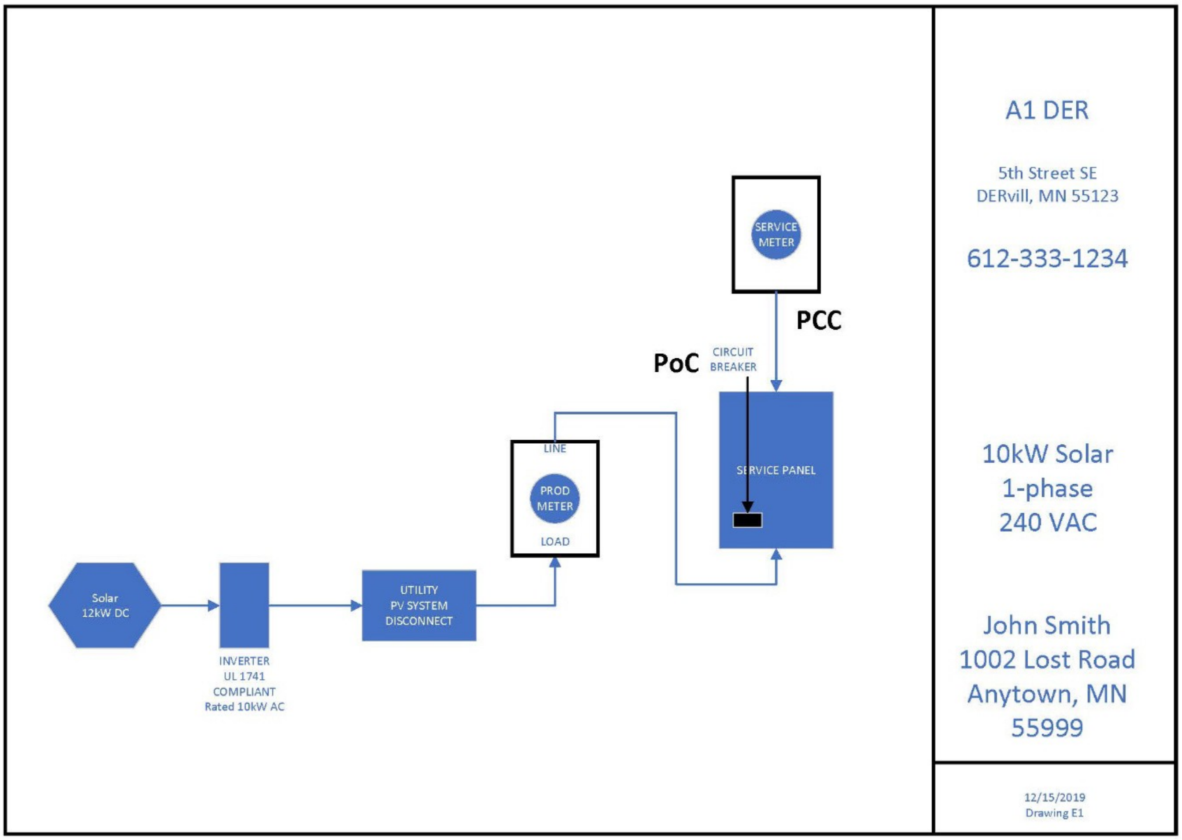
o Indicate the Point of Common Coupling (PCC)

o Indicate the Point of Connection (PoC)

o For Energy Storage Systems (ESS) the mode(s) of operation being applied for shall be clearly indicated on the one-line

o For DER systems larger than 250kW, a signature from a professional electrical engineer, licensed in the State of Minnesota

Notes:
When multiple DER units are existing or proposed on a single service: if a single Utility AC Disconnect cannot be used to disconnect all DER, all Utility AC Disconnects should include numerical identification such as “Utility AC Disconnect 1 of 2” or similar.



14.2. Equipment Certification Information

The interconnection application requests information about certified equipment. The information provided is used by the City of Saint Peter during the review process to assure compliance with local and national requirements and for documentation of the equipment proposed to be installed. The information being requested includes the following equipment.

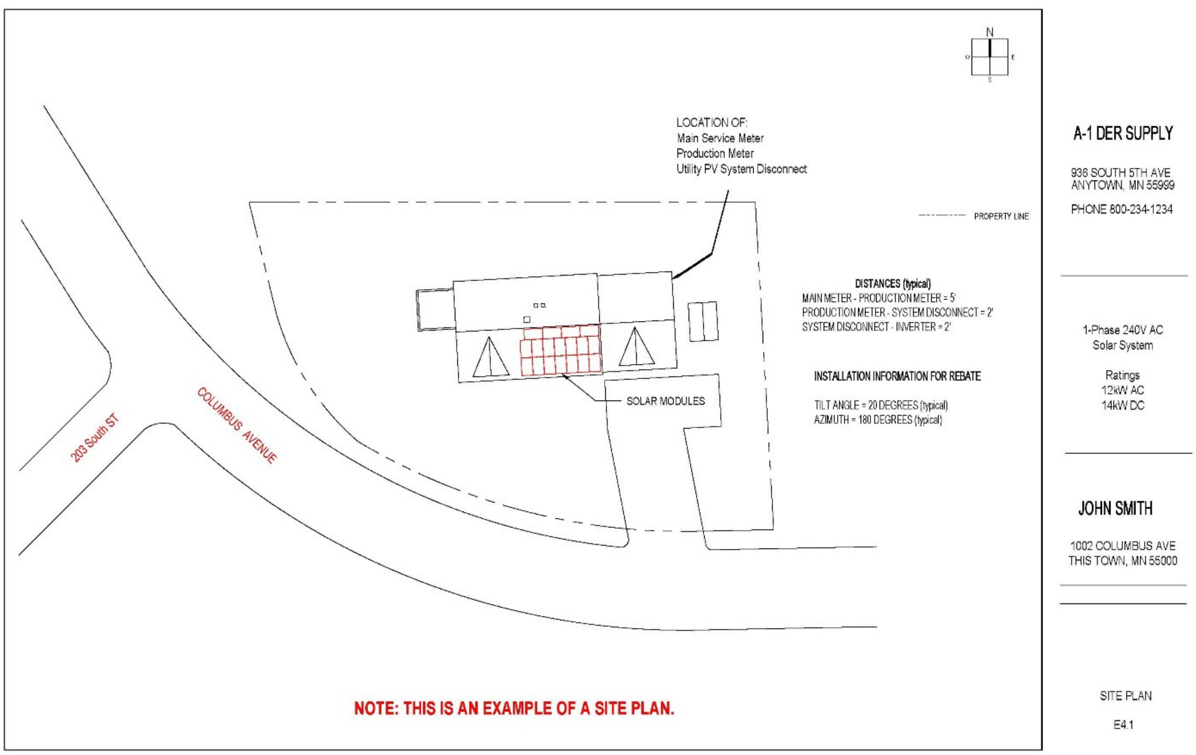
- Inverter make and model number
- Power Control system (please attached description and cut sheet)
- Energy Storage System, make and model number
- Protective Relays, make and model number

14.3. Site Diagram/Plan

The site diagram or location plan that identifies the location of the equipment noted on the one-line, shall provide the following information. If required multiple drawings may be provided to reduce overall clutter and improve the ability to read the information. Note: A Google Earth photo also would be acceptable.

- Name of the Customer located at the electrical service where the DER is proposed to interconnect

- Address of the proposed DER installation
- Installer name and contact information
- The site diagram shall show at least one street on the drawing, with the street named
- Compass direction (indicate North)
- Distances between the Main Meter and the Production Meter and Utility AC Disconnect
- Location of DER equipment
- AC kW Rating



Appendix A – Protection and Connection Discussion A-1

How the DER is connected to and disconnected from the Local or Area EPS can vary. Solar and wind systems are normally interconnected using a UL 1714 certified grid inter-tie inverter. For other generation systems a mechanical transfer system is typically utilized. Most transfer systems operate using one of the following methods of interconnection for transferring the load from the Area EPS to the DER system.

Note: If a transfer system is installed which has a user accessible selection of several transfer modes, the transfer mode that has the greatest protection requirements will establish the protection requirements for that transfer system.

Open Transition (Break-Before-Make) Transfer Switch

With this transfer switch, the load to be supplied from the DER is first disconnected from the Area EPS and then connected to the DER. This transfer can be relatively quick, but the load will experience a short outage with voltage and frequency excursions during transfer. Computer equipment and other sensitive equipment will shut down and reset, unless they are protected by a UPS. The transfer switch typically consists of a standard UL approved transfer switch with mechanical interlocks between the two source contactors that drop the Area EPS source before the DER generation is connected to supply the load.

To qualify as an Open Transition switch and the limited protective requirements, mechanical interlocks are required between the two source contacts. This is required to ensure that one of the contacts is always open and the DER generator is never operated in parallel with the Area EPS. If a mechanical interlock is not present, the protection requirements are as if the switch is a closed transition switch. Open Transition switches with mechanical interlocks between the source contractors are exempt from submitting an interconnection application to the Area EPS.

As a practical point of application, this type of transfer switch is typically used for loads less than 500kW. This is due to possible step voltage issues created on the Area EPS when the load is removed from or returned to the Area EPS source. This is referred to as block load transfer. Depending upon the Area EPS's stiffness this level may be larger or smaller than the 500kW level. If the operation of the DER causes issues for other customers supplied by City of Saint Peter, it is the DER Operators responsibility to cease operation and work with the Area EPS to resolve the issue. The DER Operators is also responsible for paying for any required mitigation. If there are questions, please contact the City of Saint Peter DER interconnection coordinator to learn if the Area EPS will support the block load transfer at your location. Area EPS engineers can complete a study to review the installation.

A-2

Closed Transition (Make-before-Break) Transfer Switch

With this transfer switch, the DER generation is synchronized with the Area EPS prior to the load transfer occurring. The transfer switch then parallels with the Area EPS for a short time (500 msec. or less) and then the DER generation with the load is disconnected from the Area EPS. This transfer is less disruptive than the Quick Open Transition because it allows the DER generation a brief time to pick up the load before the support of the Area EPS is removed. With this type of transfer, the load is either being supplied by the Area EPS or the Distributed Generation.

As a practical point of application this type of transfer switch is typically used for loads less than 500kW. This is due to possible step voltage issues created on the Area EPS when the load is removed from or returned to the Area EPS source. Depending upon the Area EPS's stiffness this level may be larger or smaller than the 500kW level.

The closed transition switch shall include a separate parallel time limit relay (62PL), which is via a completely separate relay from the generation control PLC and which disconnects the DER from the Area EPS for a failure of the transfer switch and/or the transfer switch controls.

A-3

Soft Loading Transfer Switch – with Limited Parallel Operation

With Limited Parallel Operation – The DER generation is paralleled with the Area EPS for a limited amount of time (generally less than 2 minutes) to gradually transfer the load from the Area EPS to the DER generation. This minimizes the voltage and frequency problems, by softly loading and unloading the DER system.

The maximum parallel operation shall be controlled, via a parallel timing limit relay (62PL). This parallel time limit relay shall be via a completely separate relay and not part of the generation control PLC.

A-4

Soft Loading Transfer Switch – with Extended Parallel Operation

With Extended Parallel Operation – The DER generation is operated in parallel with the Area EPS. Special design, coordination and agreements are required before any extended parallel operation will be permitted. The Area EPS interconnection review will identify the issues involved.

A-5

Inverter Connected DER

This is a continuous parallel connection between the DER and the Area EPS. Solar, wind, and energy storage systems are some examples of DER systems which typically use inverters to convert from DC to AC and to interconnect to the Local EPS or Area EPS. Larger and multi-inverter systems may require additional protection systems. See the Protection section of this TSM for guidance. The design of such inverters shall either contain all necessary protection to prevent unintentional islanding, or conventional protection shall be installed to affect the same protection.

Appendix B – Protective Relaying Elements

The different types of relaying and the protective relaying elements are described below. Depending upon the type and size of the DER being interconnected with the Area EPS, there are different protective relaying requirements. Appendix A has some basic guidance for the protective relaying requirements for the different types of DER. Appendix B has more detailed information about the different protective relaying elements and some basic information why the element is used and some information about setting the relaying elements.

To ensure proper coordination with the protective devices on the Area EPS, City of Saint Peter requires the DER Operator to submit the protective relaying settings to City of Saint Peter prior to any interconnection operation. The City of Saint Peter will review the settings provided and will complete a review of the coordination between the DER protection settings and the Area EPS protection systems. This is not a complete review of the DER protection, and it remains the responsibility of the DER Operator to ensure that there is adequate systems in place to protect the DER and the general public.

Once the protective relay settings have been reviewed and approved by City of Saint Peter the DER Operator will complete a functional test of the protective relaying systems including injecting current and voltage into the relays and actually trip the associated beaker or switch.

The following is a discussion about each of the protective relaying elements.

1. Over-current relay (IEEE Device 50/51 or 50/51V) This elements senses current and triggers the tripping on current greater than a specified level. This element shall operate to trip the protective breaker at a level to ensure protection of the equipment and at a speed to allow proper coordination with other protective devices. Phase fault detection schemes are required to detect faults on the Area EPS. For example, the over-current relay monitoring the interconnection breaker shall operate fast enough for a fault on the customer's equipment, so that no protective devices will operate on the Area EPS. 51V is a voltage restrained or controlled over-current relay and may be required to provide proper coordination with the Area EPS.

2. Directional over-current relay (IEEE Device 67) This element uses the phase relationship of the voltage and current to determine direction of the fault.

3. Over-voltage relay (IEEE Device 59) shall operate to trip the DER per the requirements of IEEE 1547.

4. Under-voltage relay (IEEE Device 27) shall operate to trip the DER per the requirements of IEEE 1547.

5. Over-frequency relay (IEEE Device 81O) shall operate to trip the DER off-line per the requirements of IEEE 1547.

6. Under-frequency relay (IEEE Device 81U) shall operate to trip the DER off-line per the requirements of IEEE 1547.

7. Sync-check relay (IEEE Device 25 / 25SC) shall operate to block reclosing of a break if the voltage and/or the phase angle is greater than a preset level. Typical values for sync-check relays are +/-10% or less for the voltage and +/- 10% or less for the phase angle.

8. Phase sequence or phase balance detection (IEEE Device 47) Provides protection for rotating equipment from the damaging effects of excessive negative sequence voltage resulting from a phase failure, phase unbalance and reversed phase sequence. This element helps the DER sense loss of source issues on the Area EPS.

9. Reverse power relay (IEEE Device 32) This element senses power flowing from the DER to the Area EPS and shall operate to trip the DER off-line for a power flow to the system with a maximum time delay of 2.0 seconds. This protective element provides a form of backup protection for problems which are not detected by the other protective relaying elements.

10. Lockout relay (IEEE Device 86) is a mechanically locking device which ensures a breaker or disconnect is not automatically re-closed into a faulted piece of equipment. The lockout relay is tripped by the protective relay and intern trips the protective breaker and/or switch. When a lockout relay is required, the protective relay does not directly trip the breaker but instead sends the trip signal to the lockout relay which then trips and relays that signal to the breakers and switches which need to trip. The lockout relay is also wired into the close circuit of a

breaker or switch and when tripped by the protective relay, prevents reclosing of the breaker. This is accomplished by blocking ALL close signals from reclosing the breaker. This lockout relay then requires a manual resetting of the lockout relay before the breaker can be re-closed. These lockout 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.

11. Transfer trip – All DERs are required to disconnect from the Area EPS when the Area EPS is disconnected from its source, to avoid unintentional islanding. With larger DERs, which remain in parallel with the Area EPS, a transfer trip system may be required to sense the loss of the Area EPS source. When the Area EPS source is lost, a signal is sent to the DER to separate the DER generation from the Area EPS. The size and type of the DER vs the capacity and minimum loading on the feeder will dictate the need for transfer trip installation. The Area EPS interconnection study will identify the specific requirements.

    If multiple Area EPS sources are available or multiple points of sectionalizing on the Area EPS, then more than one transfer trip system may be required. Area EPS interconnection study will identify the specific requirements. For some installations the alternate Area EPS source(s) may not be utilized except on rare occasions. If this is the situation, the DER Operator may elect to have the DER locked out when the alternate source(s) are utilized, if agreeable to City of Saint Peter.

12. Parallel limit timing relay (IEEE Device 62PL) set at a maximum of 120 seconds for soft transfer installations and set no longer than 500ms for closed transfer installations, shall trip the DER circuit breaker on limited parallel interconnection systems. Power for the 62PL relay must be independent of the transfer switch control power. The 62PL fail-safe timer must be an independent device from the transfer control and shall not be part of the generation PLC or other control system.

13. Under power relaying protection, is a setting within a digital relay that will trip a DER if the level of energy flow from the Area EPS goes below a set value. This protection system may be used by the DER to detect faults on the Area EPS. Under powered relaying schemes must be set to trip immediately upon sensing under power levels and must coordinate with the Area EPS system. Under power relaying is not allowed for DER systems which have the potential for inadvertent energy flow onto the Area EPS.