INTERCONNECTION STANDARDS

FOR

DISTRIBUTED ENERGY RESOURCES

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1 INTRODUCTION

These standards have been established to assist distributed energy resources (DER) in planning and designing an electrical interconnection with the systems of Empire Electric Association (EEA) and Tri-State Generation & Transmission Association (Tri-State). This document should guide DER and EEA personnel when planning, installing, and operating any non-utility owned generating equipment. The following requirements are general in nature and may not cover all details of a specific installation. Potential DER should discuss project plans with EEA before purchasing or installing equipment.

2 GENERAL REQUIREMENTS FOR INTERCONNECTION

2.1 The DER must ensure that the facility and its associated equipment follow any applicable local, state, and federal government requirements or regulations, and any requirements from EEA's power supplier, transmission operator, balancing authority or any other entity having authority over the power grid.

2.2 Certain equipment (relays, circuit breakers, curtailment schemes, etc.) specified by EEA must be installed at locations where the customer wishes to operate DER facilities in parallel with EEA's system. The purpose of this equipment is to ensure safe and reliable power system operation and to allow prompt disconnection of the DER in case of short circuit or other malfunction, or to keep generation from feeding back onto the transmission system. Other changes, such as revisions to the electrical system configuration and/or modifications to protective equipment at other locations, may also be required to accommodate parallel operation. EEA will aid DER owners in determining if interconnection requirements have been met. This document gives general information about parallel operation; however, EEA may impose added restrictions or require additional equipment when the installation so warrants. Each DER must be reviewed individually since interconnection requirements vary with the type of equipment and the proposed location on EEA's system.

2.3 All costs associated with interconnection will be borne by the DER. Such costs may include, but are not limited to, system upgrades, system additions, system monitoring equipment, protective devices, power quality mitigation, power factor correction, etc.

2.4 EEA requires that the customer design, construct and operate their equipment in a manner which will not degrade the quality of service to other EEA customers. This requires that the DER equipment be designed, specified, and installed in a manner appropriate to its intended service and in accordance with all applicable standards regulating design, construction, and operation of such equipment. EEA reserves the right to specify the quality and determine the adequacy of customer equipment, installation and operation in any respect which affects safety, reliability, or quality of service.

2.5 EEA will not assume responsibility for protection of any of the DER's equipment. The DER is fully responsible for properly protecting its equipment.

2.6 A permanent and weatherproof sign indicating the location of the DER generation disconnect(s) shall be clearly displayed at the electrical service (generally at the customer meter).

2.7 The DER must comply with guidance given in PUC 4 CCR 723-3 3855 (b). Exceptions may be allowed on a case-by-case basis where safe system operation can be proven and as approved at EEA's sole discretion.

2.8 If the DER is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the DER, shall not exceed 65% transformer nameplate rating.

2.9 Three-phase services must have balanced 3-phase DER systems, in accordance with NEC 705.45 (b) and ANSI C84.1. Use of single-phase DER on a 3-phase service may require that the service be placed on its own transformer as determined at EEA's sole discretion.

2.10 Where multiple single-phase DERs are connected to a 3-phase service, the system shall be designed so that the loss of voltage on any one phase of the system will cause generation on all three phases to cease until such time that voltage is restored.

2.11 All DERs will comply with IEEE STD 1547 to prevent the formation of an unintentional island.

2.12 EEA reserves the right to limit the application of DER on existing circuits and to specify any modifications to the existing system needed to accommodate the DER. The need for such modifications will be determined on a case-by-case basis at EEA's discretion.

2.13 The DER's grounding scheme shall not in any way negatively impact EEA's system.

2.14 If EEA determines, in its sole discretion, that any DER equipment connected to EEA's system is unsafe or problematic, such equipment will be disconnected from EEA's system.

2.15 Non-exporting DERs that generate electrical energy for on-site use only and are configured or otherwise prevented from feeding energy into the EEA system are exceptional cases and may not be required to meet all the requirements of this document. However, they are required to show by design and by operation that they cannot feed energy into the EEA system.

3 CODES, STANDARDS AND REGULATORY AGENCIES

3.1 All DER installations must comply with the National Electrical Code (NEC), the National Electrical Safety Code (NESC), IEEE, ANSI, and other applicable standards, and any applicable local, state, and federal government requirements, whichever are more stringent. For a summary of applicable codes and standards, see Appendix II.

3.2 For DERs with a design capacity greater than 25kW AC, with more than one kind of generation source (i.e. solar, wind, battery, motor driven), or as determined by EEA, the DER must submit a statement from a registered Professional Electrical Engineer currently licensed in the state of the project's location (Colorado or Utah as applicable) certifying that the design of the DER and its interconnection equipment complies with EEA requirements, interconnection safety and design standards, and prudent electrical practices.

3.3 The DER agrees to hold EEA harmless for any damage to person or loss to property arising out of the DER's failure to comply with such codes or legal requirements.

3.4 The DER's installation must be inspected and certified by an electrical inspector acceptable to the Authority Having Jurisdiction before the equipment may be energized or interconnected. Inspection and startup procedures will conform to the appropriate state commission rules.

3.5 Grounding shall be in accordance with applicable sections of the NEC and the NESC and shall conform to IEEE Standard 142, "IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems" and RUS Bulletin 65-1, "Guide for the Design of Substations," where applicable.

4 POWER QUALITY

4.1 The DER will not be allowed to degrade the quality of power delivered to other EEA customers or interfere with the operation of EEA equipment. Degradation of power quality includes, but is not limited to, flicker, harmonic distortion, overvoltage, undervoltage, service interruption, etc. If degradation in quality of service to other EEA customers or interference with the operation of EEA equipment occurs, EEA will disconnect the DER until the problem is resolved.

4.2.1 If approved by EEA, the DER may actively regulate the voltage at the Point of Common Coupling (PCC) while in parallel with EEA's system. The DER shall not cause the service voltage at other services to go outside the requirements of ANSI C84.1-1995, Range A (IEEE 1547-4.1.1).

4.2.2 The DER shall operate in parallel with EEA's system in accordance with IEEE 1547-4.1.3.

4.2.3 Inverters shall not inject direct current into EEA's system.

5 SYNCHRONOUS GENERATORS

5.1 Synchronous generators are required to supply sufficient reactive power capability to withstand normal voltage variations on EEA's system and to maintain greater than 0.95 power factor at the substation.

5.2 Synchronous generators are required to have automatic synchronization equipment and supervisory relays to prevent closure into EEA's network when the DER generator is improperly synchronized.

6 INDUCTION GENERATORS

6.1 Induction generators may be started as a motor if current inrush, voltage regulation and flicker are not problems. If the quality of service to other EEA customers is degraded due to induction generator starting, reduced voltage starting, or other special procedures may be necessary to relieve the situation.

6.2 Capacitors installed at the generator may be required to limit the adverse effects of excess VAR flow on EEA's system. Installation of capacitors at or near an induction generator increases the risk of unintentional islanding. Over and under-frequency relays and voltage regulation relays are required on all induction generators to protect against self-excited operation.

7 INVERTER SYSTEMS

7.1 The inverter system should be designed and operated in accordance with UL1741 – Supplement SA and IEEE 1547 and 1547a Standard for Interconnecting Distributed Resources with Electric Power Systems (IEEE 1547 including amendment 1547a), IEEE 929 - Recommended Practice for Utility Interface of Photovoltaic (PV) Systems, where possible. In the event of conflict between this document, and UL 1741 - Supplement SA, and/or IEEE 929 and/or IEEE 1547 or IEEE 1547a, this document shall take precedence.

7.2 All three-phase inverter installations shall be served by a dedicated transformer which is connected delta on the customer side and grounded wye on EEA's side. The cost of this transformer and associated equipment shall be borne by the DER.

7.3 Inverter systems must not contribute to isolated loads (islanding) in accordance with UL-1741SA and must install protective relays to prevent isolated operation, complying with IEEE 929 - Recommended Practice for Utility Interface of Photovoltaic (PV) Systems.

7.4 Voltage

7.4.1 Inverters shall be capable of operating within the voltage range normally experienced on EEA's system from plus to minus 5% of the nominal voltage (e.g., 114 volts to 126 volts, on a 120-volt base), at the service panel or PCC. The trip settings at the DER terminals may be selected in a manner that minimizes nuisance tripping in accordance with Table 1 to compensate for voltage drop between the generator terminals and the PCC. However, the voltage range at the PCC, with the DER on-line, shall stay within +/-5% of nominal.

7.4.2 The voltage ranges in Table 1 define protective trip limits for the protective function and are not intended to define or imply a voltage regulation function. Whenever EEA's system voltage at the PCC varies from and remains outside near Nominal voltage for the predetermined parameters set forth in Table 1, the DER shall cease to energize EEA's system within the prescribed trip time. The protection function shall detect and respond to voltage on all phases to which the DER is connected, and the inverter's protective functions shall cause the inverter(s) to disconnect from EEA's system.

Table 1: Voltage Ride-Through Table

Region	Voltage at Point of Common Coupling (% Nominal Voltage)	Ride-Through Until	Operating Mode	Maximum Trip Time
High Voltage 2 (HV2)	V >120			0.16 seconds
High Voltage 1 (HV1)	110 < V < 120	12 seconds	Momentary Cessation	13 seconds
Near Nominal (NN)	88 < V < 110	Indefinite	Continuous Operation	Not Applicable
Low Voltage 1 (LV1)	70 < V < 88	20 seconds	Mandatory Operation	21 seconds
Low Voltage 2 (LV2)	50 < V < 70	10 seconds	Mandatory Operation	11 seconds
Low Voltage 3 (LV3)	V < 50	1 seconds	Momentary Cessation	1.5 seconds

7.5 Frequency

7.5.1 EEA controls system frequency, and the DER shall operate in synchronism with EEA's system. Whenever EEA's system frequency at the PCC varies from and remains outside normal (nominally 60 Hz) by the predetermined amounts set forth in Table 2, the DER's protective functions shall cease to energize EEA's system within the stated maximum trip time.

7.5.2 Inverter based systems shall remain connected to EEA's system while the grid is within the frequency-time range indicated in Table 2 and shall disconnect from the electric grid during a high or low frequency event that is outside that frequency-time range. The frequency values are shown in Table 2. These values provide default interconnection system response to abnormal frequencies. The inverter shall disconnect by the default clearing times. In the high frequency range between 60.2 Hz and 61.5 Hz, or other mutually agreed range, the inverter is permitted to reduce real power output until it ceases to export power by 61.5 Hz, or other frequency value mutually agreed between the DER operator and EEA. Islands and microgrids may need different default frequency settings.

Table 2: Frequency Ride-Through and Trip Settings

System Frequency Default Settings (Hz)	Minimum Range of Adjustability (Hz)	Ride Through Until	Ride Through Operational Mode	Maximum Trip Time
f > 62	62 - 64	No Ride Through	Not Applicable	0.16 seconds
60.5 < f < 62	60.1 - 62	299 seconds	Mandatory Operation	300 seconds
58.5 < f < 60.5	Not Applicable	Indefinite	Continuous Operation	Not Applicable
57.0 < f < 58.5	57 - 59.9	299 seconds	Mandatory Operation	300 seconds
f < 57.0	53 - 57	No Ride Through	Not Applicable	0.16 seconds

7.6 Dynamic Volt/VAR Operations

7.6.1 The inverter shall be capable of operating dynamically within a power factor range of +/- 0.85 PF for larger (>15 kW) systems, down to 20% of rated active power, and +/- 0.9 PF for smaller systems (≤15 kW), down to 20% of rated active power, based on available reactive power. This dynamic Volt/VAR capability shall be able to be activated or deactivated in accordance with EEA requirements.

7.6.2 EEA may permit or require the inverter systems to operate in larger power factor ranges, including in 4-quadrant operations for storage systems with the implementation of additional anti-islanding protection as determined by EEA.

7.6.3 The inverter shall be capable of providing dynamic reactive power compensation (dynamic Volt/VAR operation) within the following constraints:

a) The inverter shall be able to consume reactive power in response to an increase in line voltage and produce reactive power in response to a decrease in line voltage.

b) The reactive power provided shall be based on available reactive power, but the maximum reactive power provided to the system shall be as directed by EEA.

Table 3 and Figure 1 depict the default settings, which should be applied for all inverter sizes. Specific volt/var settings may be required for larger DERs (such as 100 kw or greater), or for specific areas within EEA's system as determined by EEA.

Default Open Loop Response Time for volt/var operation should be five (5) seconds.

Table 3: Voltage and Reactive Default Settings

Voltage Setpoint	Voltage Value	Reactive Setpoint	Reactive Value	Operation
V1	92.0%	Q1	30%	Reactive Power Injection
V2	100%	Q2	0	Unity Power Factor
V3	103%	Q3	0	Unity Power Factor
V4	107.0%	Q4	30%	Reactive Power Absorption

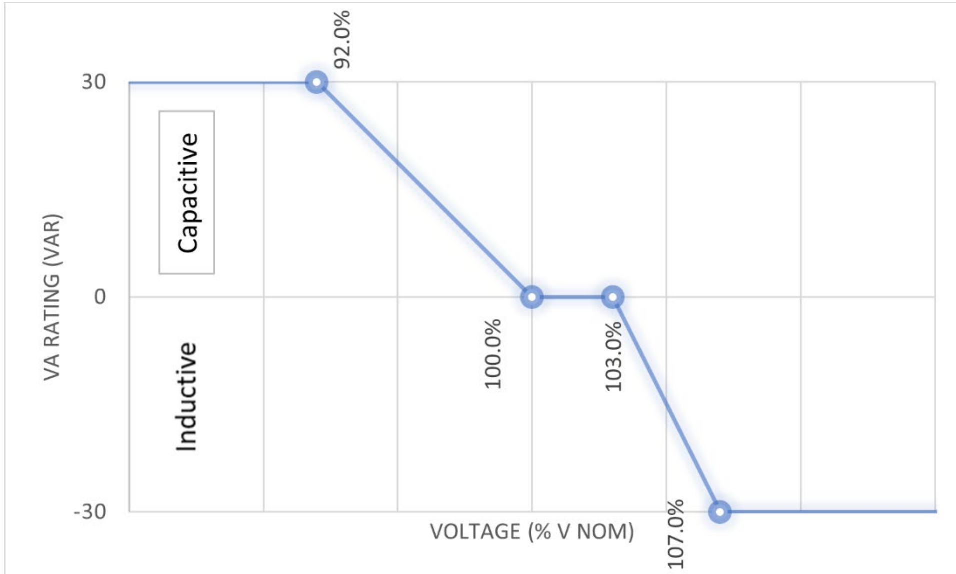

Figure 1: Voltage and Reactive Default Settings

7.7 Ramp Rate Requirements

The inverter is required to have the following ramp controls for at least the following conditions. These functions can be established by multiple control functions or by one general ramp rate control function. Ramp rates are contingent upon sufficient energy available from the inverter.

a) Normal ramp-up rate: For transitions between energy output levels over the normal course of operation. The default value is 100% of maximum current output per second with a range of adjustment between 1% to 100%, with specific settings as mutually agreed by EEA and the DER.

b) Connect/Reconnect Ramp-up rate: Upon starting to inject power into the grid, following a period of inactivity or a disconnection, the inverter shall be able to control its rate of increase of power from 1 to 100% maximum current per second. The default value is 2% of maximum current output per second, with specific settings as mutually agreed upon by EEA and the DER.

7.8 Recommended Frequency-Watt Settings

Inverters, which have this optional function available, may enable this function with the following recommended settings. Inverters with different frequency-watt capabilities may be enabled with EEA concurrence.

a) When system frequency exceeds 60.1Hz, the active power output produced by the inverter shall be reduced by 50% of real power nameplate rating per hertz (5% of real power nameplate rating reduction per 0.1 hertz)

b) When system frequency moves under 59.9Hz, the active power output produced by the inverter shall be increased by 50% of real power nameplate rating per hertz (5% of real power nameplate rating increase per 0.1 hertz) when inverter can increase real power production.

c) The default dead-band should be +/- 0.1 Hz from 60 hertz (59.9Hz to 60.1Hz). When the system frequency is in range of 59.9Hz and 60.1Hz, the inverter is not required to increase or decrease power as a function of system frequency.

d) Open loop response time for Frequency –Watt shall be 5 seconds.

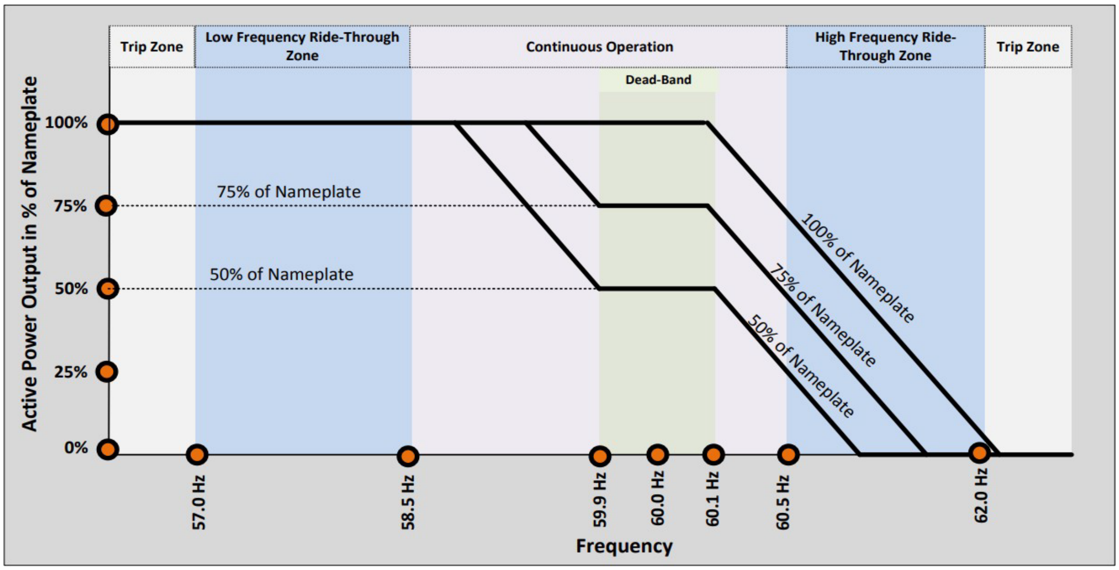

Figure 2: Active Power as a Function of System Frequency 0.1 Hz

7.9 Voltage-Watt Default Settings Requirements

Inverters shall reduce their real power production as a function measured voltage at the inverter terminal or at the PCC in accordance with the following:

a) When the measured voltage is greater than 105% of nominal voltage (Example: 126 volts on 120 volts nominal), the active power output produced by the inverter shall be reduced at a rate of 50% of real power nameplate rating per one percent of nominal voltage. Figure 3 Volt-Watt Requirements illustrate the required rate of reduction.

b) When the measured voltage is greater than 107% of nominal voltage (Example: 128.4 volts on 120 volts nominal), the active power output produced by the inverter shall be reduced to zero watts.

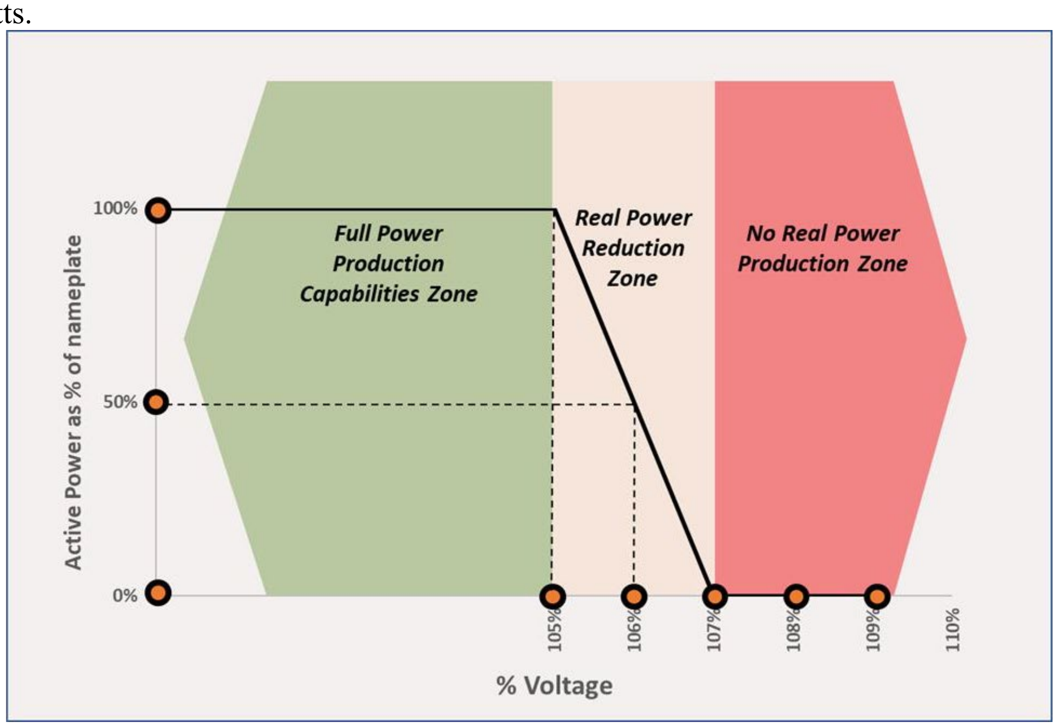

Figure 3: Volt-Watt Requirements

7.10 Default Activation State

Unless otherwise provided by EEA, the default settings will be as follows:

- Anti-islanding – activated
- Low/High Voltage Ride-Through – activated
- Low/High Frequency Ride-Through – activated
- Dynamic Volt/VAR operations – activated
- Ramp rates – activated
- Fixed power factor – deactivated
- Reconnect by "soft-start" methods – activated
- Frequency-Watt (Optional) – Implemented when available
- Volt/Watt – activated

These default activation states may be modified by mutual agreement between EEA and the DER.

7.11 Technology Specific Requirements

Grid-interactive inverters do not require separate synchronizing equipment. Non-grid-interactive or "stand-alone" inverters shall not be used for parallel operation with EEA's system.

8 PROTECTION OF THE UTILITY SYSTEM

8.1 Disconnecting/De-Energizing System

a) The DER must immediately disconnect from EEA in the event of a disturbance or fault on EEA's system.

b) The DER must disconnect from EEA's system within 2 seconds of an outage on EEA's system to avoid creating an unintentional island.

c) The DER must disconnect in the event of a malfunction or disturbance on the DER equipment.

d) The DER must not back feed a de-energized EEA line.

e) The DER must not degrade the quality of service to other EEA customers.

8.2 Visible Disconnect Required

The member shall furnish and install a ganged, manually operated isolating switch (or a comparable device mutually agreed upon by EEA and member) to isolate the DER from EEA's system. The device does not have to be rated for load break nor provide over-current protection.

The device must:

a) allow visible verification that separation has been accomplished.

b) include markings or signage that clearly indicates open and closed positions.

c) be capable of being reached: for Emergency purposes quickly and conveniently 24 hours a day by EEA personnel for construction, operation, maintenance, inspection, testing or to isolate the DER from EEA's system without obstacles or requiring those seeking access to obtain keys, special permission, or security clearances.

d) be capable of being locked in the open position.

e) be clearly marked on the submitted single line diagram and its type and location approved by EEA prior to installation. If the device is not adjacent to the PCC, permanent signage must be installed at an EEA approved location providing a clear description of the location of the device. If the switch is not accessible outside the locked premises, signage with contact information and an EEA approved locking device for the premises shall be installed.

Note: Emergency service disconnects, already installed at DER location, in compliance with NEC 230.85 may cover this requirement.

9 INSPECTION AND MAINTENANCE

9.1 The completed installation of the DER will be subject to a final inspection and test by EEA for compliance before parallel operation is permitted. EEA will determine satisfactory performance.

9.2 The DER must notify EEA prior to any modifications made to the DER or to the interconnection between the DER and EEA. The DER must receive approval from EEA prior to proceeding with such modifications. The DER must permit EEA, at any time, to install or modify any equipment, facility, or apparatus to protect the safety of its employees or equipment and ensure the accuracy of its metering equipment. These costs will be borne by the DER.

9.3 The DER must permit EEA employees to enter its property at any time for the purpose of inspecting and/or assessing the interconnection facilities to ensure their continued safe operation and the accuracy of EEA's metering equipment, but such inspection does not relieve the DER of the obligation to maintain the facilities in satisfactory operating condition.

The DER shall discontinue parallel operations when requested by EEA:

a) To facilitate maintenance, test, or repair of utility facilities;

b) During system emergencies;

c) When the DER's generating equipment is interfering with other customers on the system;

d) When an inspection of the DER reveals a condition likely to be hazardous to EEA's system; and

e) When an inspection of the DER reveals that the generating equipment is operating outside allowable limits on voltage, frequency, power factor or harmonic content.

10 REQUIREMENTS FOR INTERCONNECTION

EEA has established guidelines for the protection and interconnection of DER by size classes. These guidelines represent the minimum requirements. EEA may impose additional requirements as it deems necessary. The DER shall be the sole judge of what equipment is necessary to protect the DER generators and associated electrical equipment. EEA shall be the sole judge of what equipment is necessary to ensure a safe, reliable interconnection with EEA's system.

The size classes for DER are:

1. 10 kW and below;
2. 10-25 kW;
3. Greater than 25 kW;

10.1 DER of 10 kW or Less

The following requirements assume a low density of parallel generation customers on the service circuit.

The DER of 10 kW or less shall be required to provide:

a) An approved visible open disconnect;

b) A circuit breaker rated for the service to which it is applied;

c) A line voltage relay or equivalent control system functionality which will prevent the generator from being connected to a de-energized source;

d) Undervoltage and overvoltage relays or equivalent control system functionality;

e) Underfrequency and over-frequency relays or equivalent control system functionality;

f) A transformer dedicated to the service to which the DER is connected (when applicable).

In addition, the DER should consider installation of:

a) Thermal cutouts to protect the generator from excessive currents or single phasing (if applicable); and

b) An overspeed relay, if applicable.

10.2 DER Greater than 10 kW

The DER of 10-25 kW shall be required to provide all equipment required of 10kW or less systems as well as:

a) Surge arrestors;

b) A transformer dedicated to the service to which the DER is connected (when applicable); and

c) Protective relaying to provide the following functions:

(1) Short circuit protection;

(2) Isolation protection;

(3) Breaker closing/reclosing control; and

(4) Under and overspeed control for induction generators.

10.3 DER GREATER THAN 25 KW (THREE PHASE ONLY)

DERs greater than 25 kW in capacity may be required to install separate utility grade generation metering and will be studied on a case-by-case basis by EEA and Tri-State to determine specific requirements.

SUMMARY OF INTERCONNECTION PROCEDURE

1) Customer with potential DER contacts EEA and obtains Interconnection Application.

2) The DER submits the application with applicable fees to EEA. EEA will notify DER of application receipt within three business days of receipt.

3) For non-inverter-based DER exceeding 50kW and for inverter-based DER exceeding 1 MW, DER provides notice of insurance coverage in accordance with 4 CCR 723-3 3853 (o). The DER should investigate liability insurance coverage early in the planning stage.

4) EEA evaluates the Application for Interconnection for completeness and notifies the applicant within ten business days if the application is complete, and if not complete advises what material is missing. Residential systems greater than 10kW or other systems 25kW or greater may require EEA Board of Directors approval.

5) EEA conducts preliminary engineering studies, if warranted, to determine the effect the DER might have on existing EEA customers and equipment. EEA determines if a facility study or system impact study is required.

6) Provided all the criteria in the Interconnection Standards for Distributed Energy Resources are met, EEA approves and executes the application and returns it to the customer.

7) EEA designs and constructs the interconnection and modifies the existing EEA network as necessary to accept the DER.

8) DER system is inspected and approved by Authority Having Jurisdiction.

9) After installation, prior to parallel operation, EEA will inspect the DER for compliance with standards and applicable inverter settings and may schedule appropriate metering replacement, if necessary.

10) EEA notifies the customer in writing or by fax or e-mail that interconnection of the DER is authorized. If the witness test is not satisfactory, EEA has the right to disconnect the DER. The customer has no right to operate in parallel until a witness test has been performed.

11) Interconnection and startup.

APPENDIX II

SUMMARY OF CODES AND STANDARDS

General

- NFPA 70 (most current edition), National Electrical Code
- IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems
- UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems
- IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)
- National Electrical Safety Code
- Local Building Codes
- NEMA MG 1-1998, Motors and Small Resources, Revision 3
- NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1
- ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)
- IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms

Grounding

- REA Bulletin 65-1, "Design Guide for Rural Substations"
- IEEE Standard 142,"Recommended Practice for Grounding of Industrial and Commercial Power Systems"

Voltage Drop

- REA Bulletin 169-27, "Voltage Regulator Application on Rural Distribution Systems"
- REA Bulletin 169-4, "Voltage Levels on Rural Distribution Systems"

Phase Balance

- <3% (three phase difference)
- ANSI C84.1

Frequency

-+0.1 (for Qualifying Facility of rated capacity greater than 5 kW)

Harmonics

- IEEE Standard 519, "IEEE Guide for Harmonic control and Reactive Compensation of Static Power Converters"

Flicker

- REA Bulletin 160-3, "Engineering and Operations Manual - Service to Induction Motors"

Surge Control

- IEEE Std C62.41.2-2002, "IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits"
- IEEE Std C37.90.1-1989 (R1994), "IEEE Standard Surge Withstand Capability (SWC) Tests for

Protective Relays and Relay Systems"

- IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits Interference
- IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated

  Service Reliability
- And others which may apply

APPENDIX III

DER DESIGN DATA REQUIREMENTS

EEA reviews all proposals for interconnection by a DER. EEA attempts, as far as is reasonable, to determine whether a design will create problems on EEA's system but cannot comment or make assurances on the technical prudence or economic feasibility of a proposed project.

EEA cannot review your facility design until a complete design package is submitted. Typically, a complete design package would include:

1) A complete site plan, detailing physical locations of all equipment to be installed from EEA's supply line to the DER system. This plan should show sufficient detail to determine physical clearances between pieces of equipment and between any piece of equipment and an adjacent permanent structure. The site plan should show the location of proposed metering, disconnecting and circuit protective devices. Detail should be given to physical location of equipment in the powerhouse, and provisions for grounding of powerhouse equipment (as applicable).
2) A system one or three-line diagram which states:
    - Service disconnecting means of each service disconnect(s), and DER utility disconnect(s)
    - Ratings and types of circuit protective devices involved (fuse sizes/class, C/B trip ratings)
    - Include all equipment which has been installed or which will be installed up to EEA's interconnection.
    - Meter type/form
3) A relay control diagram which clearly shows relay contact arrangements, and which indicates functionally the operation of all relays, protective devices, and interlocks.
4) Device types, sizes, model numbers, settings and manufacturer's data on all circuit protective devices and relays.
5) The location, ratings, impedances, time constants and manufacturer's data for the generator and all associated control equipment where applicable.
6) The location, ratings and switching arrangement for power factor correction capacitors, if any.
7) Proposed operating procedures for startup, shutdown, and restart functions. The procedures should include all operational parameters and proper limits of operation.
8) Anticipated peak power production and monthly energy production figures.
9) EEA recommends not buying equipment or beginning construction of facilities until a design review is completed and EEA gives final written design approval.

Revision Dates:

1. 12/2017 – Original
2. 7/2018 – Rev. 1
3. 12/2018 – Rev. 2
4. 6/25/19 – Rev. 3
5. 10/10/19 – Rev. 4
6. 6/24/20 – Rev. 5
7. 7/30/20 – Rev. 6
8. 10/10/22 – Rev. 7
9. 6/1/23 – Rev. 8