



INTERCONNECTION GUIDELINES FOR DISTRIBUTED ENERGY RESOURCES

Black Hills Energy

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INTERCONNECTION GUIDELINES FOR DISTRIBUTED ENERGY RESOURCES

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1.0 INTRODUCTION

1.1 GENERAL

Technical Standards

This document was developed with the use of the IEEE 1547 and 1547.1 standards which will be referenced throughout. This document is intended to provide discussions, summarizations, and clarification of these standards for the use of Distributed Energy Resources (DERs), customer interconnections. Some situations are not addressed in the IEEE standards. This document provides additional details to extend the IEEE standards to these situations. The IEEE standards and State Rules do not address telemetry, direct transfer trip (DTT), potential check, metering, or other necessary details that this document will provide additional guidance and details on. Additional references that may be of use are listed in Section 11.

IEEE 1547 and 1547.1 set the performance requirements for technical requirements, interconnection equipment certification, and commission testing. Any interconnection package certified by Underwriters Laboratory (UL) under UL 1741-2010 is accepted as certified by Black Hills Energy. Other certification protocols will not be accepted. UL 1741 requires several safety and use aspects to be demonstrated in addition to the technical aspects. Certain DER configurations may be set up with 'islanding' capabilities. In these cases, the requirements in IEEE 1547-2018 will apply.

For this document, the term "Interconnection Customer" will be used to refer to co-generators, qualifying facilities (QFs), small power producers, non-utility generators (NUGs), and customer-owned generators. "Customer" is the same as "Interconnection Customer" used by State Commissions. The term "Company" will be used to refer to Black Hills Energy (BHE).

This document does not address all the nuances and complexities involved in designing an interconnection protection scheme. Extensive application, review, and testing guidance can be found in the IEEE 1547.2 guidelines. The minimum requirements for DERs to interconnect to the Company power grid safely and reliably are stated in this document. These requirements are meant to protect the Company and its other electrical consumers. The Customer is responsible for the overall safe and effective operation of their own generating facility. The Customer is responsible for designing their own protection scheme and should consult an expert in the field of system protection for its DER. IEEE 1547.2, Appendix A provides additional discussion and typical one-line diagrams for protection schemes.

Final Authority

Customers and Company personnel may be guided by this document when planning installations of distribution-connected DER. The final authority remains with the requirements of IEEE 1547 and the Company. It is emphasized that these requirements are general and may not cover all details in specific cases. IEEE 1547.2 contains extensive discussion and suggested approaches for the many nuances that may not be apparent from the text in the standards. Interconnection Customers should discuss project plans with the Company's engineers before purchasing or installing any equipment to ensure that it is compatible. The parties may *mutually agree* to requirements other than those contained in IEEE 1547 or this document.

1.2 POLICY ON INDEPENDENT GENERATION

The Company will allow any authorized Customer to operate DER equipment in parallel with the Company's distribution system whenever this can be done without undue risk or effects on the public or to Company equipment or personnel. Certain protective devices (relays, circuit breakers, direct transfer trip, telemetry, etc.) may be installed at any location where an Interconnection Customer desires to operate DER in parallel with the Company's Distribution System. The purpose

of these devices is to promptly disconnect an Interconnection Customer's DER equipment from the Company's Distribution System whenever faults or abnormal operating conditions occur. Other modifications to the Company's distribution system configuration or protective relays may be required to accommodate parallel generation. These modifications will be at the Customer's expense. Large facilities will often require the extension or rebuild of a feeder, the addition of interrupting devices, and possibly the replacement of a substation transformer or protection relaying which will be at the Interconnection Customer's expense. DERs with directly connected rotating generators will rarely be acceptable on Company's distribution system.

1.3 DER SOURCES

An Interconnection Customer may use any variety of energy sources including solar, wind, battery storage, hydro, etc. in addition to conventional fossil fuels. This document is based upon the DER technology used, not upon the fuel or energy source that is utilized. The end conversion for connection to the Company's Distribution System must be 60 Hz sinusoidal alternating current at a standard Company voltage (see Section 2.1) and phase rotation. The Customer shall verify rotation and voltages with the Company before purchasing any equipment and before final connection to the Company's Distribution System.

An Interconnection Customer may operate the DER as a separate system with the capability of load transfer between the two independent systems or in parallel with the Company's Distribution System. IEEE 1547 does not specifically cover the load transfer mode requirements. The transfer mode requirements are based upon this standard but may have less stringent requirements. Each continuously paralleling mode of operation requires a signed interconnection agreement. Machine based generation that will parallel for more than two-minutes and that will equal or exceed one (1) MW of aggregated generation requires review and a signed interconnection agreement. The technical requirements for these modes of operation are outlined in the next two subsections.

1.4 SEPARATE SYSTEMS

A separate system is defined as one in which there is no possibility of connecting the Interconnection Customer's generating equipment in parallel with the Company's Distribution System.

This can be accomplished by either an electrically or a mechanically interlocked switching arrangement which prevents the two power sources (Company and Customer) from serving a load simultaneously. If an Interconnection Customer has a separate system, the Company may require verification that the system meets the nonparallel requirements. This will be accomplished by approval of drawings by the Company in writing and, if the Company so elects, by field inspection of the transfer scheme. The Company will not be responsible for approving a Customer's Generating System and assumes no responsibility for its design, operation, or effects on the Interconnection Customer's load.

1.5 PARALLEL OPERATION

A parallel system or parallel DER is defined as one in which an Interconnection Customer's DER can be connected to the Company's Distribution System. A transfer of power between the two systems is a direct and often desired result. All revenue generation Interconnection Customers or QFs are connected in parallel with the Company.

Utility lines are subject to a variety of man-made and natural hazards (lightning, wind, ice). The electric problems that can result from these hazards are principally short circuits, grounded conductors, and open conductors. These fault conditions require that the equipment involved be de-energized as soon as possible because of the hazards they pose to the public, the Company's operating personnel, and the operation of the system. A parallel DER must have mutually agreeable and reliable protective devices installed to sense trouble on the Company's Distribution System and promptly disconnect from all sources.

Parallel generation can also cause another condition known as "islanding" in which a portion of the Company's load becomes isolated from the Company but is still connected to a Customer's DER(s). IEEE 1547-2018 and the Interconnection Agreement describes the technical requirements and conditions under which this operating mode may be permitted. The protective devices and other requirements imposed by the Company are intended to govern the parallel DER under various system conditions. These requirements are minimal for a small installation but increase as the amount and complexity of the DER increases. The general and specific requirements for parallel generation installations of various sizes are discussed in the following sections.

1.6 AUTOMATIC THROW-OVER SERVICE WITH PARALLEL GENERATION

The Company expressly prohibits the use of continuous parallel generation (greater than 2 minutes) behind a Company owned Automatic Throw-Over (ATO) equipment. The Company may permit, at its sole discretion, to allow closed transition parallel generation (less than 2 minutes) behind Company owned ATO equipment. The Company allows both closed and continuous parallel generation behind Interconnection Customer owned ATO equipment. This generation is subject to the requirements of this document. If the Customer chooses to operate in continuous parallel generation behind the Customer owned ATO equipment, the Interconnection Customer assumes all responsibility for any reliability issues, including electrical power outages and damages resulting from concurrent use of parallel DER and ATO service.

2.0 COMPANY SYSTEM INFORMATION

2.1 VOLTAGE

The Company's most common primary distribution or sub-transmission voltages are 4.16 kV, 12.47 kV, 13.2 kV, 24.9 kV and 69 kV depending on the geographic area; other voltages are sometimes used in specific areas. Virtually all the distribution circuits are "effectively grounded" (see Section 2.3) and are used to provide four-wire distribution (phase to neutral) to connected loads. Transmission delivery voltages are 115 kV, and 230 kV. This document is not intended to provide guidance for interconnections on the Company's Transmission System and the Interconnection Customer will need to contact the Company for clarification on the process that will be required. The common secondary voltages are 120/240V single-phase and 120/208V or 277/480V three-phase. Under normal operating conditions, the voltage is targeted to be within plus or minus 5% of these values.

2.2 CIRCUIT RESTORATION

Because most short circuits/faults on overhead lines are temporary, it is the Company's practice to automatically reclose circuit breakers and reclosers on most distribution lines. The delay sequences are typically, but not limited to 0.5 second, 3 second, and 5 second trip delays. The Company utilizes distribution automation for both overhead and underground feeders. Some substations are tapped to transmission lines and are subject to transmission line reclosing. Most tapped transmission reclosing has a 1.5 second delay but other delays may be used. The protective relays required by IEEE 1547 for parallel generator installations are intended to disconnect the generator(s) from faulty or isolated lines before delayed reclosing occurs. Sometimes, especially for larger units, the Customer's interconnection relaying may not be adequate or quick enough to ensure DER separation before the Company's delayed reclose. An out-of-synchronism reclose may result in damage to load or generation equipment and, for direct connected rotating generation units, may result in severe generation unit damage. Thus, the Company does require additional protective equipment and schemes to be implemented; these details are discussed within this document. This is seldom an issue for smaller, inverter-based interconnections.

Most interconnection requirements, and all certified equipment, include overvoltage and undervoltage relaying and overfrequency and underfrequency relaying. Faster tripping with smaller delta deviations in frequency and voltage will speed separation and reduce the possibility of an out-of-synchronism reclose event. However, the overfrequency and underfrequency settings must comply with the North American Electric Reliability Corporation (NERC) limits, and the overvoltage

and undervoltage settings must be able to avoid tripping for normal voltage variations and brief fault interruption voltage dips.

The hazards and possible solutions for out-of-synchronism reclosing are discussed in detail in IEEE 1547.2.

2.3 EFFECTIVE GROUNDING

The Company operates an almost entirely effectively grounded distribution system, as defined by IEEE standards, and requires that Customer generation connected to the Company's Distribution System be designed (through the selection of transformers, generator grounding, etc.) so that they contribute to maintaining an effectively grounded system. A Generation Facility that does not participate in maintaining effective grounding can, upon islanding, cause severe overvoltages to single phase loads, resulting in damage and will not be allowed to operate until the system is corrected. IEEE 1547.2 provides additional discussion on the importance of effective grounding and methods to achieve it. Most small single-phase inverter-based Generation Facilities will not require any additional design consideration to meet this requirement.

This Section is directed at Customers that operate for any extended length of time (2 minutes or longer) in parallel with the Company's distribution system. Effective grounding limits the voltage rise on unfaulted phases during single-line-to-ground fault conditions. To achieve effective grounding, an Interconnection Customer's system equivalent impedance (Thevenin equivalent impedance) must meet the following two criteria (IEEE Std 142-1982):

- 1) The positive-sequence reactance is greater than the zero-sequence resistance ($X_1 > R_0$).
- 2) The zero-sequence reactance is less than or equal to three times the positive-sequence reactance. The Company usually will require the ratio to be between 2.5 and 3.0 ($2.5 \cdot X_1 \leq X_0 \leq 3 \cdot X_1$) to limit the adverse impacts on feeder ground relay coordination.

Synchronous and Induction Generators

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

Many different system configurations will meet the effective grounding requirements. Listed below are some guidelines and restrictions.

- A grounded-wye/grounded-wye step-up transformer is common for facilities rated less than one (1) MW. When this transformer arrangement is used, the generator must have an appropriately sized grounding bank, or the generator's neutral must be adequately grounded (typically through a grounding reactor) to meet the Company's requirements for effective grounding. Wye-wye transformers over one (1) MVA should be evaluated for resonant conditions.
- A delta/grounded-wye (DER is delta and system is grounded-wye) step-up transformer must have a grounding reactor in its grounded-wye neutral connection to meet the Company's requirements for effective grounding. A neutral resistor may cause high power losses and is not recommended.
- A delta/delta step-up transformer, with delta on the Company's distribution feeder side, may be used. When this configuration is used, a grounding bank must be installed on the primary side. The grounding bank's impedance must be selected so that it meets the Company's effective grounding requirements, and it must be rated to withstand the system current imbalance and/or

voltage imbalance. This configuration requires a switching device to separate the generator and ground source during system separation.

- Generating Facilities that produce power at line voltage (i.e., a step-up transformer is not needed) either must be adequately grounded (typically through a grounding reactor in the generator neutral) or have a grounding bank to meet the Company's effective grounding requirements. Grounding the generator is not recommended because significant generator derating due to unbalanced currents may result.
- Voltage imbalance on the Company's Distribution System may result in substantial current flowing into a Interconnection Customer's generator(s) or grounding equipment. The Company's operating objective is to keep phase-to-phase imbalance under 1% and phase-to-ground imbalance under 3%. Imbalance may be higher, especially during contingency conditions. The Customer's interconnection facilities must be able to withstand allowable imbalances and be able to operate during an imbalance condition.
- Normal system source impedance data for a given location can be obtained from the Company's engineer. "Normal system" refers to the arrangement of the system most of the time. Due to contingencies and maintenance, field ties are temporarily used, and this can change the source impedance and fault duties as seen by an Interconnection Customer. Normal system source impedance should be obtained before an Interconnection Customer purchases grounding equipment so that the equipment purchased will be appropriately rated (both for steady state and short time duty) for the given location.
- The generator reactance used in calculating the ratio X_0/X_1 should be the subtransient direct axis reactance (X_d'').

Inverters, Double-fed Induction Generators, and Others

Double-fed induction generators have an equivalent short-circuit impedance that is available from the manufacturer. The equivalent combines the fault output of the stator windings and the inverter output from the rotor windings. Some double-fed generators employ a crowbar circuit on the rotor that is activated during upsets. Once the rotor is shorted, the generator acts like a standard induction generator.

Inverter installations that are large in single unit or composite facilities should be checked for effective grounding equivalency. This requirement applies regardless of the energy source providing power to the inverter. Small, single-phase inverter installations usually do not need to be checked. For three-phase installations, the neutral shift during a single-line-to-ground fault must be constrained to avoid an overvoltage condition to the single-phase loads connected to the unfaulted phases. All inverters connected to spot or area networks must be effectively grounded on the secondary side.

A three-phase installation comprised of three single-phase inverters connected in a solid grounded-wye configuration will usually meet the effective grounding requirement. Single-phase inverters connected in a delta configuration will not. Many three-phase inverters will not meet the requirement. Some manufacturers employ an internal high resistance between the internal wye and the neutral connection. Some manufacturers connect the inverters in a delta configuration. The presence of a neutral connection on the inverter does not ensure a grounded-wye configuration. Three-phase inverters normally use an internal transformer between the AC output and the inverter circuits to provide isolation and voltage matching. Either a delta/wye-grounded or a wye/wye-grounded configuration will usually provide adequate ground referencing. If the inverter does not meet the effective grounding criteria, it will need either a small grounding bank, or grounding with a wye-grounded-delta, with neutral reactor, or with step-up transformer. Reference the IEEE 1547.2 standard for further details.

Inverters may have a maximum current rating for output into a fault. This should be used if available. If this rating is not available, the following approximation is usually adequate: $X = (\text{Rated Voltage} / \text{Maximum Output Current})$. For most inverters, maximum current is the emergency rating, commonly around 110% of rated continuous output.

Generation technologies other than those discussed here may come into use. The same principles will apply to them. The energy source delivered into an effectively grounded distribution system must provide effective ground referencing.

Company Ground Relays

The Company's overcurrent relays located at our substation and on our distribution feeders will be desensitized during a single-line-to-ground fault when a Customer's DER(s) is operating in parallel. If the Customer, in aggregation with other DER on the distribution circuit, contributes more than 10% to a feeder fault, expensive corrective measures will likely be needed. Refer to Figure 2.3.1 when calculating the ground fault current before and after the addition of the Customer's DER(s). When the Interconnection Customer's grounding contribution is relatively large, the Company often must install additional feeder protection equipment at the Customer's expense to ensure a reliable and secure system configuration is maintained. The Company may be unable to allow an Interconnection Customer to add a DER to certain feeders due to feeder equipment limitations and/or grounding issues.

Non-inverter based facilities under 100 kW (at the Company's discretion, see Section 2.4) and all facilities 100 kW and higher must meet the above effective grounding requirements to operate in parallel with the Company. An Interconnection Customer must select equipment such that the impedance and fault levels meet all the above criteria.

The following diagram summarize the effective grounding methodology:

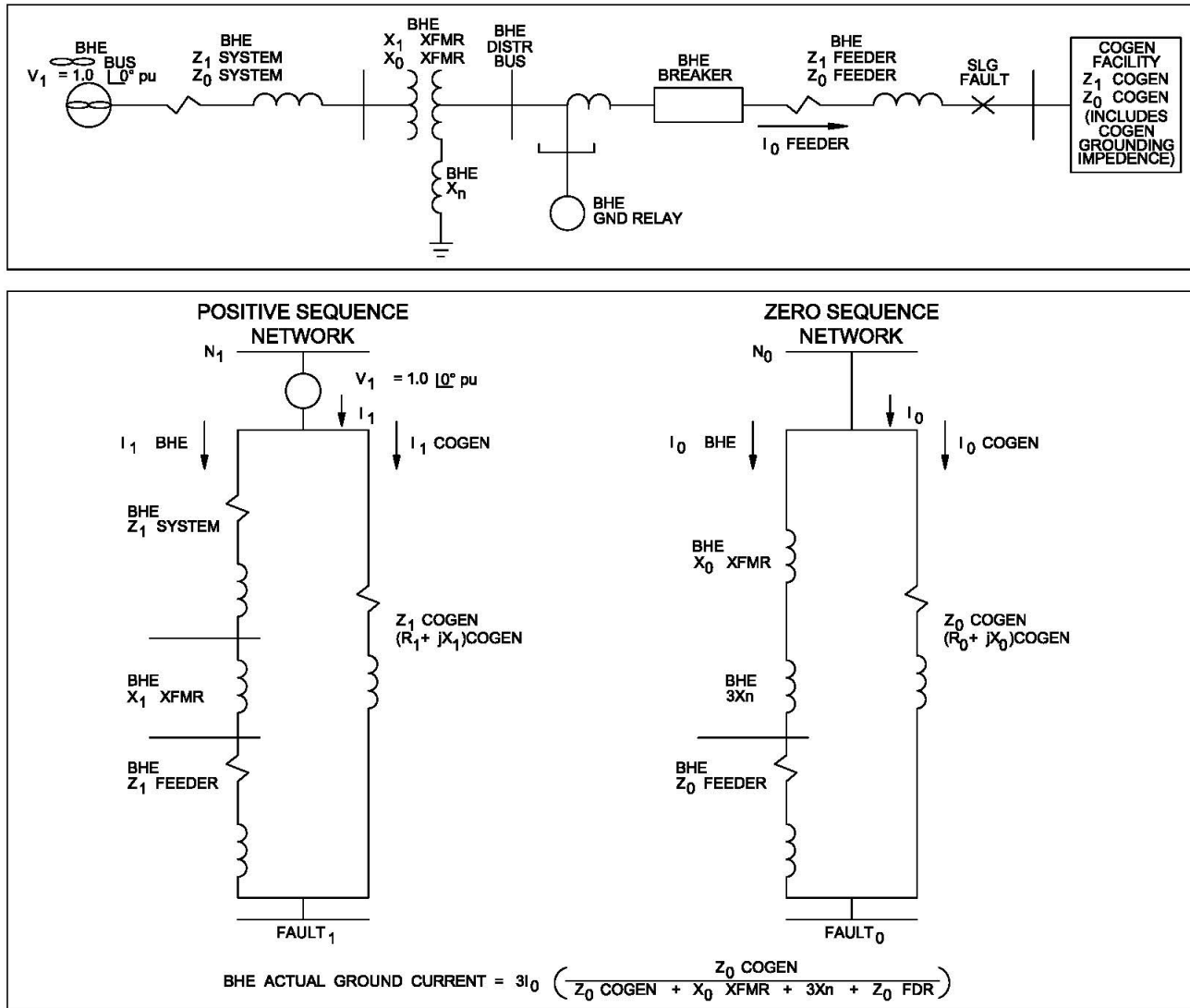


Figure 2.3.1 – Grounding Methodology

2.4 NON-EFFECTIVELY GROUNDED DISTRIBUTION CONNECTED PRODUCERS

A generator under 100 kW may not need to be effectively grounded if it can be shown that; in all possible situations where the generator is islanded from the Company and is still generating power and, the kW load on the generator during the islanding will always be at least two times greater on each phase than the generators per phase kW rating. In general, a facility under 100 kW that passes the Company's review will qualify for ungrounded operation. All inverters connected to spot or area networks must be effectively grounded on the secondary side.

3.0 SYSTEM INTEGRITY

3.1 GENERAL

The interconnection of the Customer's generating equipment with the Company's Distribution System shall not cause any reduction in the quality of service being provided to other electrical consumers. Certified inverters, unless they are malfunctioning or misapplied, will generally comply with the requirements of this section. Non-certified inverters will not be allowed to interconnect the Company's Distribution System. Certified inverters may not be acceptable without corrective

measures, such as filters, for situations where the DER outputs exceed the feeder load. Abnormal voltages, frequencies, harmonics, and interruptions must be kept within limits specified under IEEE 1547 and IEEE 519. If high or low voltage complaints, transient voltage complaints, and/or harmonic (voltage distortion) complaints result from operation of an Interconnection Customer's DER, such DER equipment shall be disconnected from the Company's Distribution System until the Customer resolves the problem. The Interconnection Customer is responsible for the expense of keeping the DER(s) in good working order so that the voltage, total harmonic distortion (THD), total demand distortion (TDD), power factor (0.95 leading or lagging), and volt-ampere reactive (VAR) requirements are always met. IEEE 1547.2 provides additional discussion and approaches for identifying and addressing these Section 3 issues.

3.2 HARMONICS

The THD from the facility will be measured at the facility's metering point or Point of Common Coupling (PCC). Harmonics on the power system from all sources must meet the requirements of IEEE 1547-2018.

In addition, any interference with other electrical consumers' equipment or communications caused by the Customer's harmonics more than federal, state, and local codes will be resolved at the Interconnection Customer's expense and the customer's DER will remain off-line until resolved by the Interconnection Customer.

3.3 DISTRIBUTION LEVEL VOLTAGE

Operation of the Interconnection Customer's DER(s) shall not adversely affect the voltage stability of the Company's Distribution System. The Interconnection Customer's DER(s) shall meet the requirements of IEEE-1547-2018.

3.4 VOLTAGE FLICKER

In normal operation, the DER shall not cause repetitive changes of power output leading to voltage fluctuations. The main concerns are rapid voltage changes (RVC) caused by switching large real or reactive power elements, a repeating power fluctuation causing flicker, and power output fluctuations that cause excessive voltage regulator operations. RVC and flicker limits are specified in IEEE 1547-2018.

3.5 Substation Power Transformers Limits

The aggregate of large DER (>500 kVA) will be limited to 50% of the substation transformer base rating. In the event this threshold is met and an Interconnection Customer (DER >500 kVA) wants to interconnect at one of these locations, the necessary upgrades that are required (based on the appropriate system studies performed by the Company), will be at the Interconnection Customer's expense. Smaller systems (\leq 500 kVA) may continue to be interconnected when these distribution transformer limits are reached.

In the case of parallel transformers, aggregate DERs shall not exceed a new reduction of 50% at all operating times. This limit is based on expected DER output and load profiles that result in the net load. An absolute limit of 50% of the transformer rating applies in cases of substations with multiple transformers and with auto-transfer capability. This will help to ensure that locations with transfer capability can operate safely where one transformer load automatically transfers to the remaining transformer. During planned events, the Company will review the switching steps and make a determination on what DER may need to be removed from the system in an effort to keep the system safe and reliable. During un-planned events, DER that is one (1) MW or greater will be tripped offline. In the event of the un-planned outage, DER(s) will be studied to understand the impact they will have on the system and either remain offline from the Company's Distribution System or brought back online if able.

4.0 GENERAL DESIGN REQUIREMENTS

4.1 CODES AND NERC STANDARDS

The Interconnection Customer's Interconnection Facilities must meet the State Regulatory Commission rules for small power production and cogeneration facilities and all applicable national, state, and local construction, environmental, and safety codes. The Interconnection Customer must also meet all applicable interconnection requirements of the Western Electricity Coordinating Council (WECC).

One or more large Generating Facilities connected to the distribution of a substation may create operational issues that affect the Transmission System to which the substation is attached. Even though this is usually not considered FERC jurisdictional, the transmission provider may place operating restrictions on the generation unit(s), such as curtailment during certain system contingencies, or require the generation facilities to pay for modifications to the Transmission System, such as the use of direct transfer trip. The Company engineer will work with the Interconnection Customer to communicate with and comply with the requirements of the transmission provider.

WECC's UFLS program and NERC reliability standard PRC-006 govern the requirements for frequency fluctuations on the transmission system. As DERs become more prevalent on the Company's distribution system, additional guidelines may be set forth that the Company and Customer must abide by.

The 2008 National Electric Code, NFPA 70, contains an article that restricts the size of inverter-based interconnection into a shared panelboard. Article 705.12(D)(2) states the following for inverter interconnections: "The sum of the ampere ratings of overcurrent devices in circuits supplying power to a busbar or conductor shall not exceed 120 percent of the rating of the busbar or conductor." For a typical 200A residential panel, this means that the breaker connecting an inverter-based supply, usually a photovoltaic system, would typically be rated at 40A or less. A 40A breaker will limit the supply to around 7 kW. A larger supply will require a larger photovoltaic (PV) system breaker, which could mean replacing the panelboard and meter with higher rated devices. If compliance is not determined prior to filing the interconnection application, significant delay may occur during commissioning.

4.2 PROTECTIVE DEVICES

Protective device (relays, circuit breakers, etc.), metering equipment, and synchronizing equipment must be installed as required by the Company. The complexity of the protective devices differs with the size of the installation (see Section 5 and IEEE 1547.2 Appendix A). The type of fault-interrupting device required for a DER facility must be determined based on the size and type of the DER, the available fault duty, the local circuit configuration, and existing Company protection equipment. The fault-interrupting device must meet the Company's specifications and reviewed and approved by the Company.

Manual Disconnect Switch and Production Meter

A manual disconnecting device that is accessible to the Company's personnel 24/7, can interrupt the rated generator and/or load current, and can be locked open with a visible open for line clearances must be provided by the Interconnection Customer. The visible open shall be viewable without unbolting covers and without assistance from site personnel. The switch must also be accessible to the Company personnel without assistance from site personnel. The form of this device will vary with the service voltage and DER capacity. See Section 12 for typical one-lines.

The manual disconnect switch must be clearly marked with a permanent, weather-proof label. For Generating Facilities where the switch and/or production meter are not located in close proximity to the Company's revenue meter, the Customer must post at the revenue meter a permanent, weather-proof, and clearly labeled map showing the location of the revenue meter, switch, production meter, and Generating Facility.

4.3 DESIGN REVIEW AND DOCUMENTATION

The Interconnection Customer is required to submit various design documentation to the Company for review and undergo specified Company-witnessed start-up testing procedures before interconnecting with the Company's Distribution System. The interconnection application specifies the information needed. For some applications, additional information may be required. The specific design documents and test procedures will vary depending for each facility; however, some general documents for the design review process are outlined below as a guide to the Interconnection Customer.

5.0 SPECIFIC SYSTEM AND PROTECTIVE RELAYING REQUIREMENTS

5.1 DER CLASSIFICATION

The Company has established classes of protective relaying for distribution interconnected generation. These are provided as guidance and are meant to be consistent with IEEE 1547. IEEE 1547.2 provides additional discussion, design considerations, and approaches to address specific applications. These classes are:

1. $\leq 25\text{kW}$
2. $>25\text{ kW to } \leq 1\text{ MW}$
3. $>1\text{ MW to } \leq 10\text{ MW}$
4. $>10\text{ MW}$ (considered transmission level interconnection or connected directly into an open feeder at the Company substation)

Where multiple DER(s) are connected to the Company's Distribution System through a single service point, the class will be determined by the sum or aggregate of the DER ratings. The classes are based upon DER or inverter nameplate ratings.

These classes have been established for convenience and are based on urban/suburban circuits with normal load density. The final decision as to the requirements for each installation will be made depending on Interconnection Customer load magnitude, the magnitude of other loads connected to that circuit or system, available short circuit contribution, source substation size, line conductor size, etc. Rural circuits often require additional measures to be taken.

The relays indicated in IEEE 1547.2, Appendix A are to be used as guidance by the Interconnection Customer when submitting one-lines for review by the Company. These features noted in the IEEE standard are for the protection of the Company. In each application, protective relaying will be reviewed by the Company as described in the following sections. Interconnection Customers shall be responsible for determining their own relay settings. An Interconnection Customer should provide documentation that their interconnection relaying and settings are in accordance with these documents before the start of relay trip checks.

For most installations, utility grade relays are required. Certified interconnection packages are accepted as complying with this criterion. The following specifies what a utility grade relay should include:

- Meeting or exceeding ANSI/IEEE Standards for protective relays (i.e., C37.90, C37.90.1, and C37.90.2)
- Extensive documentation covering application, testing, maintenance, and service.
- Positive indication of what caused a trip (Targets, Event Reports from Relay).
- A means of testing that does not require extensive unwiring (e.g. a draw out case, test blocks, FT-1 switches, etc.).

Certified Test Reports

A certified test report is a test results document that has been stamped as correct and complete by a professional engineer licensed to practice in the applicable state.

5.2 INSTALLATIONS \leq 25 kW

All installations in this class will require a design and inverter review by the Company (i.e., metering and inverter one-lines, and nameplate data of the DER(s), inverter(s) and disconnect switch(es)). The Company will determine if an inverter and site inspection (i.e., witnessing the calibration and testing of the inverters and operation of the DER, see Section 7) is required. Each package will be reviewed to verify that it is certified and applied in a manner consistent with its certification.

General requirements for these installations are shown in a one-line in Section 12. The installation must be permanently wired into a suitable load center in accordance with the National Electric Code (NEC) (see Article 690 for PV). A lockable disconnect switch that is readily accessible to the Company's personnel must be provided. This switch is to be at the metering point unless an alternate location is readily accessible and easily identifiable. The Company must approve the alternate location and a durable map or written sign will need to be provided at the metering or PCC location indicating the location of the switch.

5.3 INSTALLATIONS $>$ 25 kW TO \leq 1 MW

All installations in this class will require a design and inverter review by the Company's engineer (i.e., metering and relay one-lines, nameplate data of the DER(s), inverter(s) and breaker(s) or like equipment, disconnect switch(es) and certified test reports will be provided to the Company by the Customer). A site inspection (i.e., witnessing the calibration and testing of the relays and operation of the DER and inverters, see Section 7) is also required. Each package will be reviewed to verify that it is certified and applied in a manner consistent with its certification.

Installations in this size range may be an assembly of two or more certified interconnection packages. This is a common practice with photovoltaic sites. The certification process certifies the design and functionality for only the package with its associated energy source. It does not address the increased system impacts that multiple units will have. Because of this, a site with multiple packages must be reviewed and additional protective equipment and field-testing may likely be required for the larger composite installations.

The intent of the protective relaying requirements is given in the IEEE 1547.2, Appendix A standard and within this document.

5.4 INSTALLATIONS $>$ 1 MW TO \leq 10 MW

All installations in this class will require a design and relay review by the Company (i.e., metering and relaying one-lines, protection and control schematics, relay setting sheets, nameplate data of the DER(s) and breaker(s) or like equipment and disconnect switch(es). Certified test reports will be provided to the Company by the Customer. A site inspection (i.e., witnessing the calibration and testing of the relays and operation of the generator and breakers, see Section 7) is also required.

Installations in this size range may be an assembly of multiple certified interconnection packages. This is a common practice with PV sites. The certification process certifies the design and functionality for only the package with its associated energy source. It does not address the increased system impacts that multiple units will have. Because of this, a site with multiple packages must be reviewed in aggregate and additional protective equipment and field-testing will likely be required.

Many rural systems will not accept this class of generation or may require extensive rebuilding and reinforcement of the distribution system. The Interconnection Customer may have to interconnect with the Transmission System or pay for the necessary upgrades to the system to accommodate the interconnection.

General requirements for these installations are shown in a one-line in Section 12. With some installations, the transformer and associated equipment are owned by the Interconnection Customer instead of the Company. Utility grade protective relays and utility grade equipment are required.

5.5 INSTALLATIONS >10 MW

In general, the Company's Distribution System is designed to handle loads and DERs up to and including ten (10) MW for urban/suburban circuits. Installations more than ten (10) MW are usually served from a sub-transmission (69 kV) or transmission (115 or 230 kV) system, or routed into an unused, dedicated feeder breaker at the Company's substation site.

5.6 HOT TRANSFER STANDBY GENERATORS

A Hot Transfer Standby Generation system is defined as one in which an Interconnection Customer's generation can be connected to the Company's Distribution System for more than 2 minutes. These generators fall under the same requirements as a generator that is continuously connected to the Company. For systems that operate in an open transition mode, see Section 1.4. For systems that operate in parallel for less than 2 minutes, see section 5.8. Since this type of installation often employs a sensitive direction power relay to aid in separation, some of the interconnection requirements may be relaxed.

5.7 DEMAND REDUCING GENERATORS

A Demand Reducing Unit (sometimes referred to as a "peak shaving" unit, where the local demand is reduced) is one where a Customer is paralleled with the Company, but no power is intentionally shipped to the Company and the Company purchases no power. Only those installations permitted under the filed Company tariffs may be interconnected. As with the Hot Transfer Standby Generator installation, the relaying requirements will usually be the same as a generator designed for continuous connection to the Company's Distribution System. The size classification (see Sections 5.2 through 5.5) will be determined from the generator's rating and if more than one generating unit is at the site, all the generator's ratings will be aggregated to determine the classification. Since this type of installation often employs a sensitive direction power relay to aid in separation, some of the interconnection requirements may be relaxed.

5.8 CLOSED TRANSFER SYSTEMS

A closed transfer system is defined as one in which the paralleling of the Company's Distribution System and the Customer's Generation System is less than two (2) minutes. If the paralleling time has been exceeded, a breaker (or like equipment) or switch must be automatically tripped to isolate the Company's Distribution System from the Customer's Generating Facility. Because of the complexities in the closed transfer system(s), each installation will need to be reviewed on a case-by-case basis. Due to the brief nature of the paralleling exposure, reduced interconnection requirements may apply, such as waiving the effective grounding requirements in some cases. Machine based generation that will parallel for more than two (2) minutes and that will equal or exceed 0.5 MW of aggregated generation requires review and a signed interconnection agreement.

5.9 HIGH SPEED TRANSFER SWITCHES

A high-speed transfer switch with switching times of less than 500 ms is classified as a high-speed transfer system. Because of the complexities in the high-speed transfer switch(s), each installation will need to be reviewed on a case-by-case basis. In addition, assuming the Company has not previously reviewed the proposed high-speed transfer switch, the Interconnection Customer is to provide the Company with documentation of the switch's ratings, manufacture's drawings of the

switch, and the manufacture's specifications for the switch. Due to the high speed, if suitable interlocks and synchronism check features are present, no further requirements may be needed.

5.10 POTENTIAL CHECK FOR RECLOSING

This section provides the requirements for when potential transformers will be required (or verified they are in use and fully operational) and reasons why this is required when interconnecting to the Company's Distribution System. Conventional distribution systems have been designed with the expectation that there would not be any sources of energization connected to the feeder after opening of the normal feeder source at the substation. Interconnection of DERs to the feeder, with sufficient aggregate capacity to support the connected load, creates the potential for the distribution feeder to remain energized after the feeder breaker/recloser or line recloser is opened, also called islanding. This continued energization creates possible issues of public, company employee and system safety, as well as power quality issues. However, the most significant issue is the possibility of the feeder breaker/recloser or line recloser reclosing when the DER-fed island and the utility source voltages are out of phase (due in part to the inverter not operating correctly). The addition and/or use of a three-phase potential transformers and check before reclosing is enabled at the upstream protective device (substation breaker, recloser or line recloser) and will be required for inverter-based systems or as approved by the Company.

The following bulleted list provides guidance on why the Company requires potential transformers at their upline protective device for these certain DER interconnections:

- In the event a fault is detected on the Company's feeder, the upline substation feeder breaker/recloser or line recloser of the DER interconnection point needs to operate or lock open. Company requires qualifying DER interconnections to verify or implement the potential check at the upline Company protective device to protect Company assets, adjacent electric consumer equipment, and the Customer's equipment from damage from an over-voltage scenario or an out of phase reclosing operation. The over-voltage would come from a Interconnection Customer generating back onto the Company's Distribution System while the upline breaker, recloser, or line recloser is reclosing or locked out due to a fault. Out of phase reclosing is when there is the potential for two (2) different frequencies to meet at a point on the distribution system or at the device that is reclosing. This can cause overvoltages, overcurrents, and damage equipment from large torques.
- Additionally, the Company's standard practice is dual redundancy for protection equipment. As an example, the Company installs two relays for each feeder breaker on new or retrofit builds. This is due to the potential that one of the relays fails, there is a backup relay to ensure proper operation and clearing of a fault that occurs. Thus, the potential check at the upline Company protective device is seen as the dual redundancy option to ensure that damage is limited to only the fault and that additional damage is not encountered for an over-voltage or out of phase reclose. A Interconnection Customer's DER could otherwise inject power back onto the Company's distribution system if the inverter were to fail to operate correctly when the upline substation breaker/recloser or line recloser is locked open or reclosing. Dual redundancy protection with a potential check at the upline Company protective device scheme may also be required in addition to the anti-islanding protection inherent in customer owned inverters. Anti-islanding functions on DER inverters do not eliminate the need for the potential check, as the speed of island detection is insufficient to coordinate with any potential "instantaneous" reclosing requirement on the Company's feeder.
- Distribution feeders must be de-energized by opening their circuit breaker or recloser in response to a fault for elimination of dangerous conditions (e.g., line down, high impedance fault, or other protection criteria), circuit maintenance, or system reconfiguration.

Requirements for the potential check at the upline Company protective device is dependent on the criteria stated within this section. In addition, the potential check at the upline Company protective device may be required if it is determined that conditions may exist that could jeopardize the reliability, security, or safety of the distribution system. The Company will make the final determination of whether the potential check at the upline Company protective device is required.

The following bullet items describe when the potential check at the upline Company protective device may be required:

- The potential check at the upline Company protective device is required for inverter based DER, one (1) MW or greater, or when the connected DER exceeds 15% of the minimum connected load to the feeder. The potential check at the upline BHE protective device may also be required on installations smaller than one (1) MW for out of phase reclosing prevention or if deemed necessary by the Company for the safe operation of the Distribution System.
- When the capacity of any interconnection is greater than 1/3 of the minimum daytime load or the generation has the potential to back-feed onto the Transmission System.
- The potential check at the upline Company protective device is not required for DER connected to a dedicated feeder (no other customers are served from that feeder breaker). If other distribution load is ever connected to a dedicated feeder of DER, then the potential check at the upline Company protective device will be required at the interconnection customer's expense based on the requirements listed above.
- In situations where it is determined that conditions exist that potentially jeopardize the reliability and security of the Company's Distribution System, the potential check at the upline Company protective device may be required at the expense of the Interconnection Customer.

Where the potential check at the upline Company protective device is required, implementation shall meet the following requirements:

- The corresponding feeder breaker/recloser or line recloser will either be reprogrammed with the addition of the potential transformers to allow for the potential check at the upline Company protective device or if the relay is not capable of the functionality, it will be replaced with a new relay. The new relay will correspond to the Company's standard relay type for feeder breakers and will be at the interconnection customer's expense.
- Connection from the potential transformers (installed outside the substation fence on the distribution feeder) will have a direct path through cable to the feeder breaker/recloser or line recloser relay. Radio or cellular communication will be considered in the event the cost is substantially less, due to timing, or if the burying of cable through the substation is prohibited.
- Settings for the potential check at the upline Company protective device will follow the Company's standard programming and align with IEEE-1547 tripping requirements.
- The DER interconnection breaker shall not be closed or remain closed if the potential check at the upline Company protective device is out of service during normal configuration of the system. The DER interconnection interrupting device must be opened if the required potential check at the upline Company protective device scheme is out of service for any reason.
- Functional testing of the potential check at the upline Company protective device shall be required and conducted by the Company to verify the setup is compliant with design.
- The potential transformers shall meet the Company's standard. The cost for the material and installation will be at the Interconnection Customer's expense.
- It is the responsibility of the Interconnection Customer to protect the DER system and equipment against possible damage when operating parallel to the Company's system. Where the potential check at the upline Company protective device is used or required it is for the protection of the Company's Distribution System. The potential check at the

upline Company protective device does not guarantee protection of DER equipment. Implementation of DER protection shall not interfere with or degrade any performance required in this document or in any applicable standard, including the latest version of IEEE 1547.

5.11 DIRECT TRANSFER TRIP

This section shall provide the requirements for DTT and reasons why DTT is required when interconnecting to the Company's Distribution System. Conventional distribution systems have been designed with the expectation that there would not be any sources of energization connected to the feeder after opening of the normal feeder source at the substation. Interconnection of DERs to the feeder, with sufficient aggregate capacity to support the connected load, creates the potential for the distribution feeder to remain energized after the feeder breaker/recloser or line recloser is opened, also called islanding. This continued energization creates possible issues of public, company, employee and system safety, as well as power quality. However, the most significant issue is the possibility of the feeder breaker/recloser or line recloser reclosing when the DER-fed island and the utility source voltages are out of phase. The addition and/or use of DTT will be required for only certain types of interconnections listed later in this section.

The following bullet items provide guidance on why the Company requires DTT for certain interconnections:

- In the event a fault is detected on the Company's feeder, the upline substation feeder breaker/recloser or line recloser of the DER interconnection point needs to operate or lock open. The Company requires qualifying DER interconnections to implement DTT to protect the Company's assets, adjacent electric consumers equipment, and the Interconnection Customer's equipment from damage from an over-voltage scenario. The over-voltage would come from a Customer generating back onto the Company's Distribution System while the upline breaker/recloser or line recloser is reclosing or locked out due to a fault.
- In the event a fault is detected upline of the DER interconnection point and the upline substation feeder breaker/recloser or line recloser needs to operate (reclose), Company requires qualifying DER interconnections to implement DTT to protect Company assets, adjacent electric consumer equipment, and the Interconnection Customer's equipment from damage from an out of phase reclosing operation. Out of phase reclosing is when there is the potential for two different frequencies to meet at a point on the distribution system or at the device that is reclosing. This can cause overvoltages, overcurrents, and damage equipment from large torques.
- Additionally, the Company's standard practice is dual redundancy for protection equipment. As an example, the Company installs two (2) relays for each feeder breaker on new or retrofit builds. This is due to the potential that one of the relays fails, there is a backup relay to ensure proper operation and clearing of a fault that occurs. Thus, the potential check at the upline Company protective device is seen as the dual redundancy option to ensure that damage is limited to only the fault and that additional damage is not encountered for an over-voltage or out of phase reclose. An Interconnection Customer's DER could otherwise inject power back onto the Company's Distribution System if the Generation Facility were to fail to operate correctly when the upline substation breaker/recloser or line recloser is locked open or reclosing. Dual redundancy protection with a DTT scheme may also be required in addition to the anti-islanding protection. Anti-islanding functions on certain generation facilities do not eliminate the need for DTT, as the speed of island detection is insufficient to coordinate with any potential "instantaneous" reclosing requirement on the Company's feeder.
- Distribution feeders must be de-energized by opening their circuit breaker/recloser or line recloser in response to faults for elimination of dangerous conditions (e.g., line down, high impedance fault, or other protection criteria), circuit maintenance, or system reconfiguration.

Requirements for DTT are dependent on DER size, technology, and load on the feeder section relative to the aggregate DER capacity on the entire line section. In addition, DTT may be required if it is determined that conditions may exist that could jeopardize the reliability and security of the Distribution System. Company will make the final determination whether DTT is required.

The following bullet items describe when DTT is required:

- DTT is required for all synchronous generators greater than 500 kW.
- The requirements for DTT for an induction generator shall be determined by the Company. This will be done in consideration of the characteristics of the reactive compensation design and the relative minimum system loading. This minimum system loading is related to the aggregate generation capacity on the distribution feeder section.
- DTT may be required when the capacity of any rotating generation is greater than 1/3 of the minimum daytime load or the generation has the potential to back-feed onto the Transmission System.
- DTT is not required for a generation facility connected to a dedicated feeder (no other customers are served from that feeder breaker). If other distribution load is ever connected to a dedicated feeder for a generation facility, then DTT will be required at the Interconnection Customer's expense based on the requirements listed in this section.
- In situations where it is determined that conditions exist that potentially jeopardize the reliability and security of the Company's Distribution System, DTT may be required at the expense of the Interconnection Customer.

Where DTT is required, implementation shall meet the following requirements:

- The corresponding feeder breaker/recloser or line recloser will either be reprogrammed to allow for the DTT operation or if the relay is not capable of the functionality, it will be replaced with a new relay. The new relay will correspond to the Company's standard relay type for feeder breakers and will be at the Interconnection Customer's expense.
- Based on the terrain (line of sight), distance, and obstructions to the upline substation from the point of interconnection; one of the following types of communication paths may be utilized from the generation facility site to the upline protective device. The Interconnection Customer is responsible for obtaining the communication method for telecommunications and/or DTT protection signals. The Company will have final approval on the communications path to be used.
 - Dedicated Fiber
 - Dedicated Radio System
 - Cellular
 - Others as approved by the Company
 - In the event communications is lost between the protective device at the Customer's point of common coupling and the upline protective device, a timer will be programmed into the protective device at the Customers interconnection site to trip the device. This will ensure that an out of sync reclose won't happen.
- Settings for the DTT setup will follow the Company's standard programming and align with IEEE-1547 tripping requirements.
- The interconnection protective device shall not be closed or remain closed if the DTT device or associated communication path is out of service. The DER interconnection must be offline and removed from utility interconnection if the required DTT scheme is out of service for any reason.
- Functional testing of the DTT shall be required and conducted by the Company to verify the DTT scheme is compliant with design.

- It is the responsibility of the Interconnection Customer to protect the Generation System and equipment against possible damage when operating parallel to the Company's system. Where DTT is used or required, it is for the protection of the Company's Distribution System. A DTT scheme does not guarantee protection of DER equipment. Implementation of DER protection shall not interfere with or degrade any performance required in this document or in any applicable standard, including the latest version of IEEE 1547.

5.12 GENERAL TELECOMMUNICATION REQUIREMENTS

The Interconnection Customer will be responsible for acquiring the communication lines from the local phone company, as required to meet the electronic communications required of the new interconnection. If protective relay channels (requires communications channel) are needed, the Company will provide them at the Interconnection Customer's expense.

Due to the critical nature of the protection, metering, SCADA, and electronic communication requirements, the Company will define the technical requirements and may choose to provide all or portions of the communication channels on its existing internal communication network at the Interconnection Customer's expense.

Due to the highly specialized and critical nature of the electronic communication equipment, as well as the safety and reliability considerations involved, the Company requires that all such equipment, the exception of the installation of optical ground wire (OPGW) or all dielectric self-supporting (ADSS) be installed, owned, and maintained by the Company at the Interconnection Customer's expense.

Considering the critical protection requirements for the interconnection of the DER facility to the Company's Distribution System and with the varied Company internal electronic communications systems that may be available for the specific DER, the electronic communication channels must be defined on a case-by-case basis.

6.0 METERING REQUIREMENTS

6.1 GENERAL

Metering installation requirements for the different categories of Customer-owned energy resources are the same as those outlined in the Black Hills Corporation Standards for Electric Meter Installation and User manual. The metering voltage will usually be the same voltage as the point of delivery. The metering tariff to be used should be identified before or during the interconnection application process. If this is not done, or a change in tariff is requested while the application is under review, potential delays to project review or commissioning may occur.

Typically, high side metering will be used when an Interconnection Customer owns the facility transformer, and low-side metering will be used when the Company owns the facility transformer. High-side metering usually occurs when the Customer is large and, on a transmission, or primary rate. In some cases, the Company may agree to meter on the low-side, or customer-side, of the transformer. In this case, the Customer must provide transformer test reports and any other related conductor or bus information so that the Company can calculate and apply a "loss adjustment" through the transformer. Typically, the metering will be located on the Company-owned side of the PCC of the electric facilities.

Regardless of the size of the facility or options used, all metering installations must be reviewed and approved by the Company's Electric Meter Services Department.

All Interconnection Customer meter configurations should meet the requirements of the appropriate metering tariff or State rules and the requirements outlined in the Black Hills Corporation Standards for Electric Meter Installation and Use manual. It is the Interconnection Customer's responsibility to bring their equipment into compliance with Company requirements prior to approval of an interconnection application.

6.2 METERING CONFIGURATIONS

Net Metering

For instances where the Interconnection Customer elects to participate in a Net Metering program as allowed by the appropriate metering tariff or State rules, an AMI Bi-directional Meter is required, and, in some instances, an AMI Production Meter is required. In most cases, the existing demand meter socket can be utilized to install the bi-directional meter.

Production Metering

A production meter is often desired and, in some cases, required to record production from energy resource installations. If deemed necessary by the appropriate metering tariff or State rules, a production meter shall be provided and installed by the Interconnection Customer. If the appropriate metering tariff or State rules do not require a production meter for energy resource installations, the Company reserves the right to furnish and install a production meter at the Company's expense.

Until such time that the Company installs the Company owned Production Meter, the Interconnection Customer has the option of either installing a Customer-owned "test meter" or an approved meter cover over the meter socket. Under no circumstances is the meter socket to be left open or otherwise exposed at any time. After initial Interconnection Customer testing is completed, the Interconnection Customer Generating Facility must be turned off. Once the Interconnection Customer notifies the Company that the Generating Facility is ready for the Company site inspection and/or Production Meter installation, the Company will schedule the installation of its Production Meter. The Company will then remove any Interconnection Customer installed test meter(s) or meter cover(s), install an AMI type Production Meter along with any associated metering equipment, and seal the meter socket and metering enclosure.

6.3 METER COLLAR ADAPTERS

The use of a meter collar adapter shall be permitted as an additional interconnection option for the customer DER system. A meter collar is an "extension" device placed between the meter socket and the Company's bi-directional billing meter. Meter collar adapter usage shall comply with all applicable requirements listed in this manual, the Black Hills Corporation Standards for Electric Meter Installation and Use manual, state and local Commission rules, tariffs on file, and the provisions, if any, stated in an applicable Interconnection Agreement. A current list of meter collar adapters approved by the Company for installation and use is included on the Company web site.

Device Requirements

- o Device must be UL Listed or possess equivalent Nationally Recognized Testing Laboratory (NRTL) certification compatible with the device's intended use.
- o Device must be equipped with an integrated overcurrent protective device sized appropriately for the DER system.
- o Devices requiring field wiring external to the device must be equipped with a means to facilitate a weatherproof connection. This connection shall have a means to be locked or sealed by the Company.
- o Device must include manufacturer labeling.
- o Device must be compatible with Meter Form Types 2S and 12S.
- o Device must be compatible for use with ringless-type meter sockets rated for 200 amperes.
- o Device must be internally bonded and grounded to provide connection to the neutral circuit within the meter socket.
- o No more than one (1) meter collar adapter is permitted per meter socket or base.
- o The Customer should refer to the tariff on file and the state and local rules and regulations for more information on meter collar adapter procurement, installation, and maintenance responsibilities within their electric service territory.
- o Customers are not allowed to remove the meter to install the collar. Customers must coordinate with the Company for the meter removal and replacement.

- o The Company, at its sole discretion, may permit the use of a meter collar to facilitate a connection for Electric Vehicle (EV) charging or other applications.

Requests for Device Approval

The process for submitting non-approved meter collar adapter devices for review and inclusion on the approved devices list is shown below.

1. Requestor must submit an email to the Company indicating the request for meter collar adapter device approval at BHESolar@blackhillscorp.com.
2. Request must include:
 - a. Manufacturer name
 - b. Equipment type and model number
 - c. Indication of the intended application and use of the requested equipment.
 - d. Nationally Recognized Testing Laboratory (NRTL) certification(s) and associated test reports for the equipment being requested. Certification documents must be signed or stamped and dated by the NRTL.
 - e. Supporting documentation such as additional manufacturer or standards tests or specifications.
3. Requestor must provide the Company with at least one (1) sample device identical to the device requested for approval to facilitate Company inspection and review.

Requests that are complete and accurate on their first submission will be completed within 60 days from the date the request was received. The Company will notify the requester if clarification or additional information is required, or the request is rejected because of omissions or deficiencies.

7.0 DEMONSTRATION OF SYSTEM AND PROTECTIVE DEVICES

7.1 GENERAL

The commission testing and demonstration shall be conducted in accordance with the requirements of IEEE 1547.1 and requirements set forth within this document. IEEE 1547.2 provides additional information to consider for commissioning tests. This section provides additional discussion that may be of use in devising and performing these tests. This discussion is focused primarily on the needs of large facilities and a number of the steps and tests can be skipped for medium to small facilities. Assets that will be owned and operated by the Company will be tested by the Company at the Interconnection Customer's expense.

The demonstration should be divided into three parts: calibration, trip checks, and on-line testing. The calibration section is to demonstrate that the agreed upon settings are used on each of the relays required by the Company. This section also demonstrates that the relays are functional and calibrated to manufacturer's tolerances. The trip checks are to ensure that each of the required relays operate the proper device(s) and that device interlocks operate correctly. Testing to confirm accurate timing of trip functionalities, will need to be completed. On-line tests are to verify expected operation of relays, sync check, and interlocks specific to the Company-Customer interface. The Company recommends the performance of similar tests for the Customer's other relays to insure thorough generator protection. All the initial start-up tests (i.e., Section 7.2 to 7.4 or equivalent) must be successfully completed and demonstrated before permanent interconnection with the Company's system. Additional checks may be needed for special features such as direct transfer trips, potential checks, or connection to a network.

The following calibration, trip checks, and on-line testing sections are intended to serve as a suggested approach. The actual tests to be performed and the steps to complete the demonstration will depend upon the specifics of the installation, final approved AC/DC schematics, relay settings, etc. These testing procedures are intended to be non-destructive. The Company will not be liable for any equipment damage or injury resulting from the use of these testing procedures. It is the Interconnection Customer's responsibility to demonstrate the operation of all interconnection protective devices in a safe manner that does not adversely affect the Customer

or Company equipment. The Interconnection Customer is responsible for developing the final testing plan that will be reviewed by the Company.

7.2 CALIBRATION

Acceptance testing documentation from the manufacturer showing the completion of the following checks of the various equipment may be acceptable. This will be reviewed on a case-by-case basis.

CT's: Visually check polarity mark orientation on all CT's with respect to the three-line diagrams in the design drawings, the manufacturer's drawings, and the bridging philosophies. Perform polarity checks of the CT's per ANSI Standard C57.13.

The following CT tests should be performed:

- Verify the CT polarity electrically relative to the polarity marks (physical), the bridging direction (electrical), and the drawings.
- Verify that all grounding and shorting connections and test blocks provided make good contact.
- Confirm CT single point grounding for each CT circuit as shown on the drawings, with the preferred grounding location at or near the relay panel.
- Ratio check CT's at all taps.
- Perform Megger tests on all CT's to ground.
- Perform demagnetization and excitation tests on CT's as the final tests on CT's.
- Check excitation test data against CT excitation curves.

All CT's should remain shorted until testing procedures show the CT's are properly loaded. Once testing has been completed, make sure all appropriate CT secondary terminal block shorting screws are completely removed.

VT's, PD's, CVT's, and CCVT's: Visually check polarity mark orientation on all VT's, PD's, CVT's, and CCVT's with respect to the three-line diagrams in the design drawings and the manufacturer's drawings. Test all polarities per ANSI Standard C57.13.

- Verify polarity electrically relative to polarity marks.
- Verify ratio at all taps.
- Verify VT, PD, CVT, and CCVT circuit single point grounding as shown on the drawings.
- Doble power factor test all VT's, CVT's, and CCVT's.
- Adjust the potential devices (PDs) for the voltage and the burden of the secondary circuits to which they are being connected.

Relays: Test according to manufacturer's acceptance specifications. Test relays with actual setting values to verify calibration. If possible, this can be completed as part of the relay acceptance test. All testing and calibration of CT's, VT's, and relays should be performed with test equipment of recent calibration.

7.3 TRIP CHECKS

All required relays should be functionally operated to demonstrate proper breaker/recloser/VFI operation. Tests can be performed off-line if possible. Tests that cannot be performed off-line should be demonstrated to functionally operate on-line. Trip outputs from the relay may be arrived at either by manually operating all appropriate contacts (dictated by design) or by injecting an electrical signal to cause a trip output. If an 86 and/or a 94 relay is used, then the trip circuit should be proven a minimum of one time through the entire scheme (including breaker/recloser/VFI trip).

All other trips may then be performed in such a manner so only the 86 and/or 94 relay trips.

- Verify that breaker/recloser/VFI(s) cannot be manually or automatically closed with the trip relay in the latched or trip position.

- Demonstrate that both the synchronism check and synchronizing relays' wiring is correct and that the interlocks operate correctly. Note - to be checked during On-Line Tests.
- Demonstrate that the interlocks between the generator and the Company's breakers operate properly,
i.e., Interconnection Customer cannot energize a dead line and can only tie to an energized line via a synchronizing device.

7.4 ON-LINE TESTS

This section describes typical test procedures. The specific test procedure will be tailored by the type and size of the specific facility. It is the responsibility of the Interconnection Customer to supply the actual written test procedure including the following types of tests to the Company for review before actual on-line testing.

For generation systems greater than one (1) MW, a power quality analyzer (provided by the Customer) should be used to monitor all three-phase currents, three bus voltages, grounding bank neutral current or generator neutral current, and an auxiliary contact from the Interconnection Customer's generator breaker and the Company's line device(s), when used. The analyzer should have a minimum sample rate of 167 microseconds (128 points per cycle). The analyzer should monitor the pre-breaker close conditions, the breaker closing, and the post-close conditions of the system. Smaller generation sites may require this type of monitoring if the paralleling of the two (2) systems produces a noticeable voltage dip or surge. This type of monitoring equipment may not be available locally; therefore, the Interconnection Customer should plan and arrange for this equipment to be rented from a national rental facility.

Items "a" through "f" should be performed with the generator breaker 52G racked out in the test position and the line breaker 52L/T closed, energizing the transformer.

- a) Voltage Relay. Device 27: Before putting the generator on-line, lift the potential to the relay. Expected result is the operation of Device 27 after the specified time delay.
- b) Ground Voltage Relay. Device 59N: Verify proper voltage present at relay input (relay may not be applied to smaller generation units).
- c) Frequency Relay. Device 81 O/U: Verify proper voltage present at relay input.
- d) Phase Sequence and Voltage Balance Relay. Device 47 (or 47/27): Interchange two of the potential inputs to this relay to simulate a negative (reverse) phase sequence condition. The expected result is the operation of this relay after the specified time delay. Also, lift one potential lead and observe relay trip output. Once testing of this device is completed, restore the potential input connections to their original polarities. An alternative test is to perform a relay "phase-out" by checking the voltage inputs to the relay for proper magnitude and phase angle relationship with a phase angle meter, and voltmeter.
- e) For synchronous generators, phase-out and check the rotation of the primary potential on both the incoming and running sides of the generator breaker with the generator running unloaded, i.e., between the generator and the Company. The primary phase-out voltage measurements are typically performed using two sets of hot sticks (supplied by the Interconnection Customer's testing group) to verify zero voltage across the generator poles on two phases simultaneously. While performing the phase-out and rotation check, test phasing and rotation across the open generator breaker using synchroscope and voltmeter for VT secondary verification. Verify a single sync path exists through the sync-select switch on the multi-unit operations. With the generator breaker still racked out in the test position, verify that the speed matching/synchronizer (15/25), in conjunction with the sync-check (25x) relay, gives a breaker close output at the appropriate synchronized conditions (proper voltage magnitude match, phase rotation, phase angle match, and proper slip rate).
- f) For induction generators, allow the prime mover to rotate the generator with generator breaker open. Then, with the prime mover removed and stopped, use a suitable voltage to bump the machine to verify electrical rotation. Expected result is the same direction of rotation.
- g) Shut off the generator, open the line breaker, and rack in the open generator breaker. Close the line breaker, start up the generator, and synchronize the generator to the Company's energized transformer. Verify that acceptable minimal flicker occurs at the close of the generator breaker and that the generator runs in a stable unloaded condition in parallel with

the Company. Synchronizing should normally take place while the sync-scope is moving in the "fast" direction (generator faster than system) but this is not required. A power quality analyzer (supplied by Interconnection Customer's testing group) should be used to verify proper breaker pole alignment and voltage flicker, (see Section 3.3). Voltage and current harmonics from the generator should also be measured and must fall within the IEEE 519 harmonic limits (see Section 3.2).

- h) Reverse Power Relay. Device 32: With the generator on-line, cause the generator to motor. The expected result is the operation of Device 32 after the specified time delay. An alternate test is to perform a relay "phase-out", under load, at the directional relay, by checking the voltage and current inputs to the relay for proper magnitude and phase angle relationships using a phase angle meter, voltmeter, and ammeter.
- i) Overcurrent Relay. Device 51V: With the generator on-line, run the generator above the zero-voltage current pick-up level with voltage applied; lift the potential. The expected result is the operation of Device 51V after the specified time delay.
- j) Differential Relays. Device 87B, 87T: With appropriate precautions made so as to not trip the unit off line during testing, measure the secondary currents (magnitude and phase angle) coming to the relay (and CT summation cabinet for 87B), from each CT, and measure appropriate relay differential and restraint currents. For 87B relays, also measure voltage across appropriate relay voltage element (e.g., 87L operate element). Verify proper operation of associated 86 lockout relay(s) etc.
- k) Power Factor Controller Test. This test is typically applicable only for Interconnection Customers less than ten (10) MW rated and connected to distribution feeders. This test should be done with plant load that can be interrupted during test procedures. Many power factor (PF) controllers (e.g., Basler) typically have a bias limit adjustment that may need to be adjusted to assure the voltage regulator operates in the proper voltage control range. The bias limit must be set to greater than approximately 30%.
 - 1. With the generator off-line, measure the PF of the full house power kW load. The measured value will usually be lagging, not unity.
 - 2. Set the generator PF controller to a more leading PF (usually unity) this creates a VAR mismatch between the load and generator. Also, temporarily block the 81 O/U relay.
 - 3. Bring the generator on-line. The generator should serve the station service load.
 - 4. Match the generator kW to the house power load.
 - 5. Trip the line breaker.
 - 6. The generator should trip on low voltage due to PF mismatch by means of the undervoltage relay.
- l) A demonstration of compliance with the contracted PF should be performed for induction generators and inverters.
- m) Upon the completion of On-Line Tests and final verification of relay settings applied to the specified Customer's relays, these relays should be sealed.

From time to time, new requirements for testing, equipment, and or performance are established by NERC, State Regulatory Commission, etc. for interconnected DER. Failure to comply with those requirements may result in monetary penalties assessed to the Interconnection Customer or to the Company as the entity responsibility for regional interconnected system reliability. The Company requires those interconnected to us to meet future testing and/or performance requirements as applicable and be obligated to pay any monetary penalties, incurred by the Company resulting from their non-performance.

8.0 GENERAL OPERATING REQUIREMENTS

8.1 DE-ENERGIZED CIRCUITS

The Interconnection Customer will not be permitted to energize a de-energized Company circuit under any circumstances without prior Company permission. Failure to observe this requirement will be cause for immediate disconnection of the DER facility. In addition, the Interconnection Customer will be held responsible for all damages and injuries resulting from such actions.

8.2 OPERATIONAL LOG

Interconnection Customers shall maintain an operating log at each generating facility 500 kW and over indicating changes in operating status (available or unavailable), maintenance outages, trip indications, or unusual conditions found upon inspection.

8.3 TELEMETRY

Purpose:

For the safe and reliable operation of the Company's Distribution System, real-time information is required from certain DER installs. The Company requires visibility of interconnections to understand how much energy the DER is producing onto the grid and what energy flow is capable for that DER at any given time. This is especially important at times when the Distribution System is heavily loaded, paired with a sudden loss of DER generation, and/or abnormally switched.

Monitoring and Control:

Increasing sophistication of DER requirements becomes necessary as facility size and functionality increase, as well as when DER penetration on the grid increases. As grid needs change, the Company may require controls to adjust; for example, a different mode of operating control, ride-through settings, etc. As directed by the Company, the Interconnection Customer shall adjust necessary settings, test for functionality, and provided written notice that necessary changes were completed.

Cyber Security:

For DERs, cyber security requirements continue to evolve and changes in security for monitoring and control are expected. The sophisticated nature of the information and the various communication methods will drive the type and level of security needed for an installation. Larger DERs will require more extensive cyber security due to their greater impacts on the system and the more extensive control requirements that they will require. Due to remote monitoring and control, the addition of a communications security device will become a normal requirement when public communications channels and internet communications are used. General cyber security guidance is given in IEEE 1547.3, latest edition. However, due to the rapidly changing technology and the threats to the electric grid, cyber security is a dynamic area of application that must be carefully and closely controlled.

Requirements

The following bullet items describe when telemetry is required:

- a) Customer facilities one (1) MW and greater, or when the connected DER exceeds 15% of the minimum connected load to the feeder are required to provide and pay for telemetry as part of the required system modifications. This includes the Customer's site-end terminal equipment, any added metering, interface security device when needed, and ongoing secure communication channel costs to the designated Company point of interconnection. If there is co-location with another or an existing DER asset and the aggregate of the existing and proposed DER is one (1) MW or greater, telemetry will be required for the entire DER system.
- b) The Company requires the ability to remotely disconnect or curtail the generation for installations one (1) MW and greater, or when the connected DER exceeds 15% of the minimum connected load to the feeder, depending on the operational needs of the grid. For some installations, a remote ability to change control modes, such as power factor setting, may be required. This will be determined during the review process prior to the interconnection agreement becoming finalized.
- c) BHE standard interruption equipment will be installed, at the Interconnection Customer's expense, to provide the control required. The control of this device is designed and intended to comply with the NERC standards, State and Local Commission Rules, tariffs on file, and the provisions, if any, stated in the operating attachment to the Interconnection Agreement.
 - a. Interruption equipment can consist of a recloser, VFI or other approved device by the Company

- d) Location of the interrupting equipment will be at a mutually agreeable location but must be accessible 24/7 to the Company utility line trucks and other Company utility equipment.
- e) The Interconnection Customer and the Company will establish a mutually agreeable arrangement in order to provide the secure communications channel to BHE's dispatch facility or other designated location to provide the required communication path between the DER facility and the Company. The Company will define the needed minimum security, real time power flow and other requirements needed. This will be determined in the facility review.
- f) A table of typical data points is shown in Section 13. This list is to be used for guidance on what will typically be required but additional points may be needed as the technology evolves.

9.0 TYPICAL RELAYING ONE-LINE DIAGRAMS

The typical one-line diagrams are attached at the end of the document.

10.0 DEFINITIONS

The definitions defined in the "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces", IEEE 1547-2018; apply to this document as well. The following definitions are in addition to the ones defined in IEEE 1547-2018, or are repeated from the IEEE 1547-2018 standard. If a conflict arises in these definitions, the meaning shall be consistent with IEEE 1547-2018 in reference to interconnection technical requirements.

Advanced Metering Infrastructure (AMI) - The Company-owned metering system whereby electrical meters transmit electric usage and other data via a radio and/or cell phone communication system to a central data collection system.

Bi-directional Meter - A meter having two separate metering registers, one to record electricity delivered to Customer and the other to record electricity received from Customer.

Company – Black Hills Energy - area electric power system (EPS) that serves the Local EPS. The Company has primary access to public rights-of-way, priority crossing of property boundaries, etc.

Continuous Parallel Generation – A generation facility is defined as operating in continuous parallel with the Company's Distribution System whenever the parallel condition exceeds 2 minutes, and that duration is limited by built in timer and/or interlocks. Any operation in parallel that is not limited by built in timer and/or interlocks is treated as continuously parallel regardless of actual duration.

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

Distribution System – The Company's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from substations with higher voltage transmission networks which transport bulk power over longer distances. Specific to the Company, distribution system voltages are typically rated at 25 kV and below.

Distribution Upgrades - The additions, modifications, and upgrades to the Company's Distribution System at or beyond the point of interconnection to facilitate interconnection of the Generating Facility and render the service necessary to affect the Interconnection Customer's operation of on-site generation. Distribution upgrades do not include Interconnection Facilities.

Engineer – An individual that has received a Bachelor of Science degree and now uses scientific knowledge to plan, design, construct, or maintain a system or architecture.

Generating Facility - Any device producing electrical energy, i.e., rotating generators driven by wind, steam turbines, internal combustion engines, hydraulic turbines, solar, fuel cells, etc.; or any other electric producing device including energy storage technologies.

Generation System - the interconnected DER(s), controls, relays, switches, breakers, transformers, inverters, and associated wiring and cables up to the Point of Common Coupling. This is also referred to as the “Generation Facility.”

Interconnection Customer – Any entity, including utility, any affiliates or subsidiaries that proposes to interconnect its small generating facility with the Company’s Distribution System. The Interconnection Customer is also referred to as the “Customer”.

Interconnection Facilities - The Company’s Interconnection Facilities and the Interconnection Customer’s Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Common Coupling, including any modification, additions, or upgrades that are necessary to physically and electrically interconnect the Generation Facility to the Company’s Distribution System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades.

Line Section - That portion of a Company’s Distribution System connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

Local EPS - An electric power system (EPS) contained entirely within a premise or group of premises. This is also referred to as the “Customer” or “Generation Facility”.

Meter Collar Adapter - A device that is installed between the electric meter and the meter socket box on a utility customer’s premises and that has electrical connection points both electrically upstream and electrically downstream of the meter.

Net Metering - Net metering is the process of measuring the difference between the energy supplied to a customer by the utility and the energy fed back to the utility by a customer’s electric generation system during the customer’s billing period. A Bi-directional Meter is required to be installed to perform Net Metering.

Point of Common Coupling (PCC) - The point where the Local EPS is connected to the Company’s Distribution System.

Production Meter - A Company-owned electric meter installed at a Generating Facility and configured to record or allow calculated energy output of the Generating Facility. The Production Meter will be an AML type, unless otherwise specified by the Company.

Soft Loading Transfer - A method of generation load transfer that parallels for typically less than two (2) minutes, limited by timer or interlocks, to gradually transfer load between the generator and the Company. This is also called “Closed Transition”.

System - The facilities owned, controlled, or operated by the Company that are used to provide electric service under Company’s tariff.

Transfer System - A device or system that can transfer load from one path or source to another. Used to increase reliability and service during an outage as one example.

Transmission System - Those facilities as defined by using the definitions established by the Federal Energy Regulatory Commission (FERC).

Utility - A utility or public utility serving retail electric customers subject to the jurisdictional Commission.

11.0 REFERENCES

The following standards shall be used in conjunction with this manual. When the stated version of the following standards is superseded by an approved revision, then that revision shall apply.

IEEE Std 100 (2000), "IEEE Standard Dictionary of Electrical and Electronic Terms"

ANSI/IEEE Standard 142-1991, "IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems – Green Book"

IEEE Std 242 (1986), "Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems"

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

IEEE Std 519 (1992), "IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems"

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

IEEE Std 1547.1 (2005), "IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems"

IEEE Std P1547.2 (2008), "Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems"

IEEE Std P1547.3 (2007), "Guide for Monitoring Information Exchange and Control of DR Interconnected with Electric Power Systems"

ANSI/IEEE C37.90 (1989), "IEEE Standard for Relay Systems Associated with Electric Power Apparatus"

IEEE Std C37.90.1-1989 (1995), "IEEE Standard Surge Withstand Capability (SEC) Tests for Protective Relays and Relay Systems".

IEEE Std C37.90.2 (1995), "IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers"

ANSI/IEEE C37.95 (1989), "IEEE Guide for Protective Relaying of Utility-Consumer Interconnections"

ANSI C62.1, "Surge Arresters for AC Power Circuits"

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

IEEE Std C62.42 (2002), "IEEE Recommended Practice on Surge Testing for Equipment Connected to Low Voltage (1000V and less) AC Power Circuits"

ANSI/IEEE C84.1 (1995), "Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)"

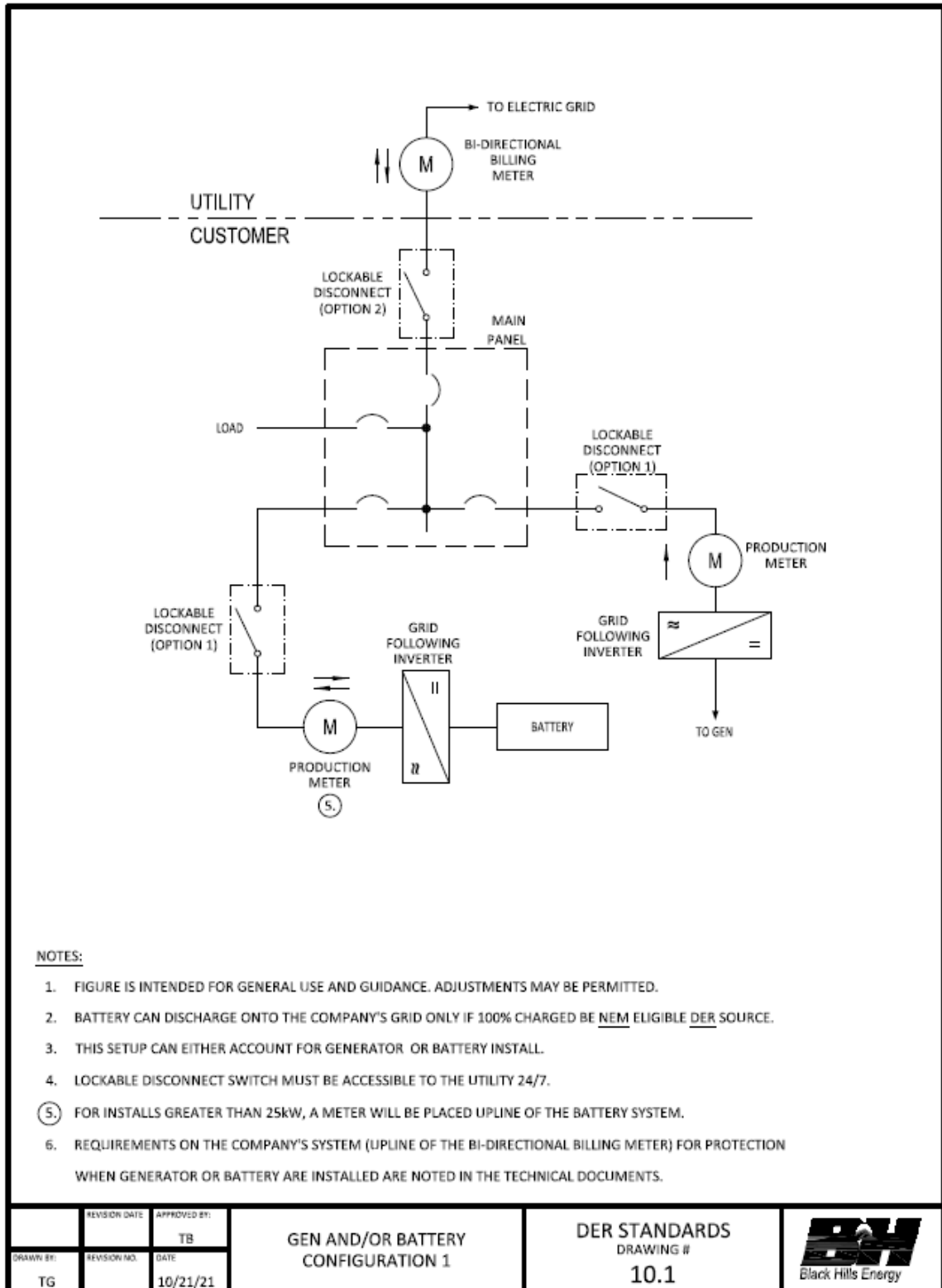
NEC – "National Electrical Code", National Fire Protection Association (NFPA), NFPA-70-2002

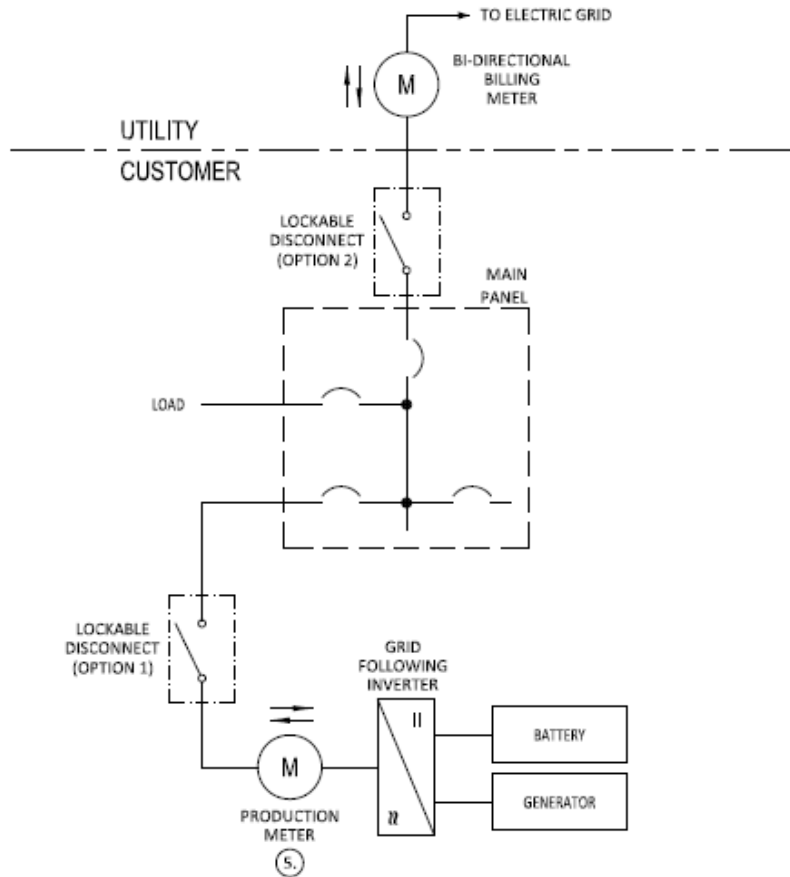
UL Std. 1741 "Inverters, Converters, and Controllers for use in Independent Power Systems"

NESC – “National Electrical Safety Code”, ANSI C2-2007, Published by the Institute of Electrical and Electronics Engineers, Inc

NEC – “National Electrical Code”, NFPA 70, Published by the National Fire Protection Association


12.0 TYPICAL ONE-LINE DIAGRAMS

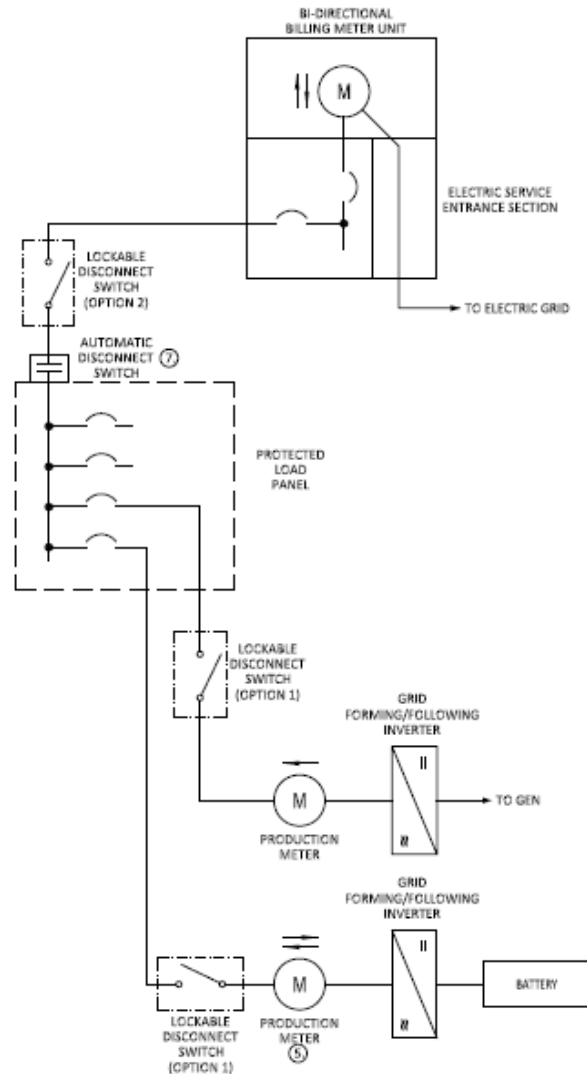




NOTES:


1. FIGURE IS INTENDED FOR GENERAL USE AND GUIDANCE. ADJUSTMENTS MAY BE PERMITTED.
2. BATTERY CAN DISCHARGE ONTO THE COMPANY'S GRID ONLY IF 100% CHARGED BY NEM ELIGIBLE DER SOURCE.
3. THIS SETUP CAN EITHER ACCOUNT FOR GENERATOR OR BATTERY INSTALL.
4. LOCKABLE DISCONNECT SWITCH MUST BE ACCESSIBLE TO THE UTILITY 24/7.
- ⑤. FOR INSTALLS GREATER THAN 25kW, A METER WILL BE PLACED UPLINE OF THE BATTERY SYSTEM.
6. REQUIREMENTS ON THE COMPANY'S SYSTEM (UPLINE OF THE BI-DIRECTIONAL BILLING METER) FOR PROTECTION WHEN GENERATOR OR BATTERY ARE INSTALLED ARE NOTED IN THE TECHNICAL DOCUMENTS.

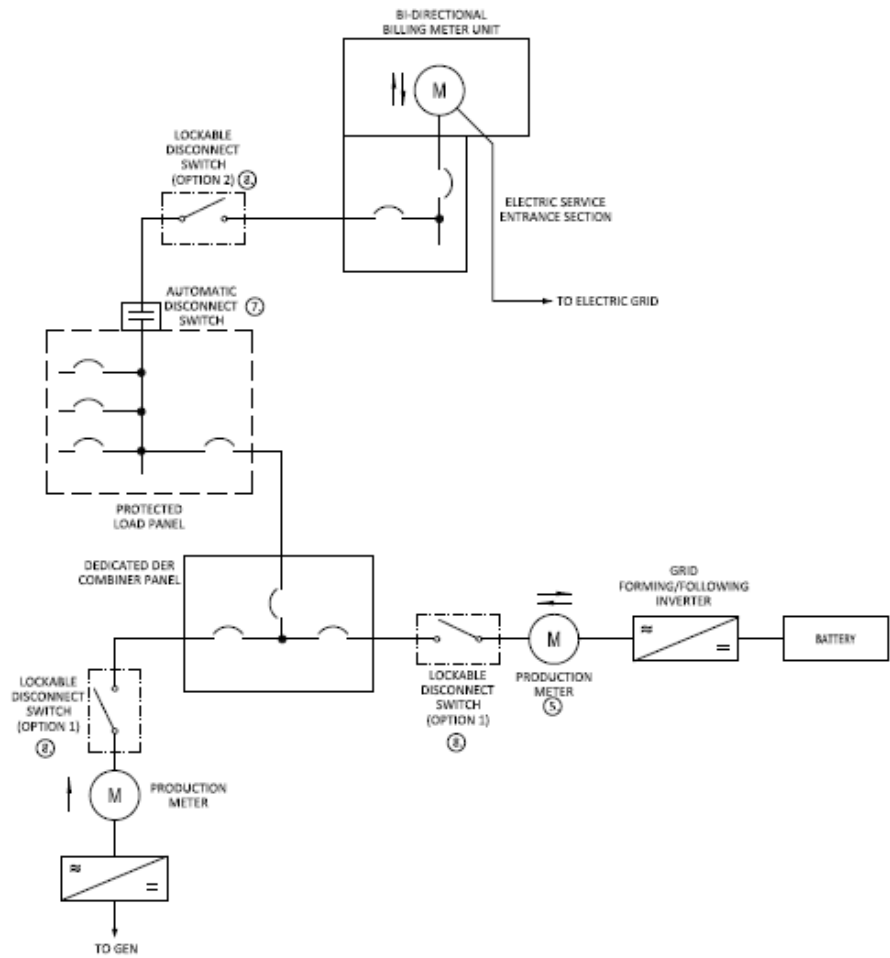
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| | | TB | | | |
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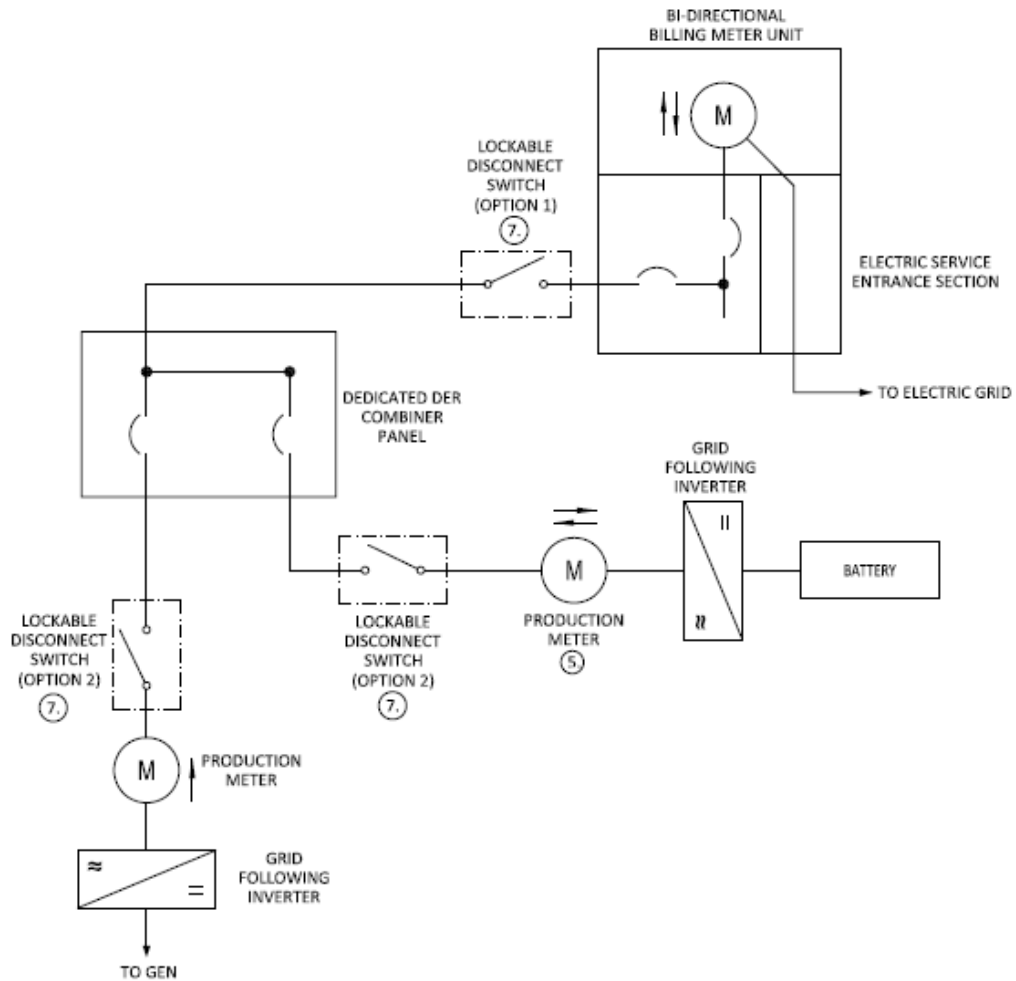
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8. IF THE CUSTOMER PROVIDES DETAILED DOCUMENTS THAT SHOW THE DER COMBINER PANEL HAS AN INTEGRATED LOCKABLE DISCONNECT SWITCH AND ALWAYS ACCESSIBLE TO THE COMPANY, THE ADJACENT SWITCHES MAY NOT BE NECESSARY.

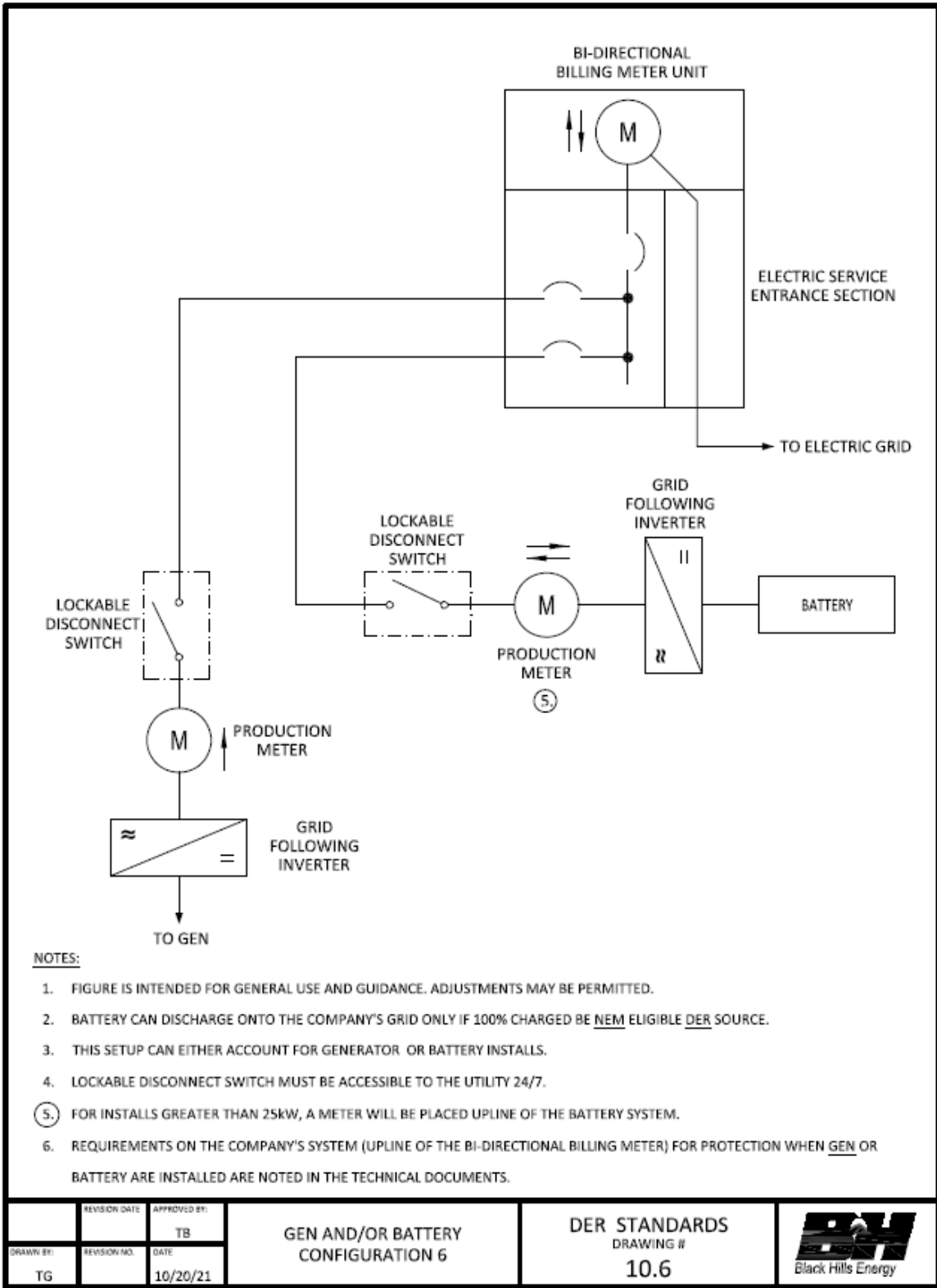
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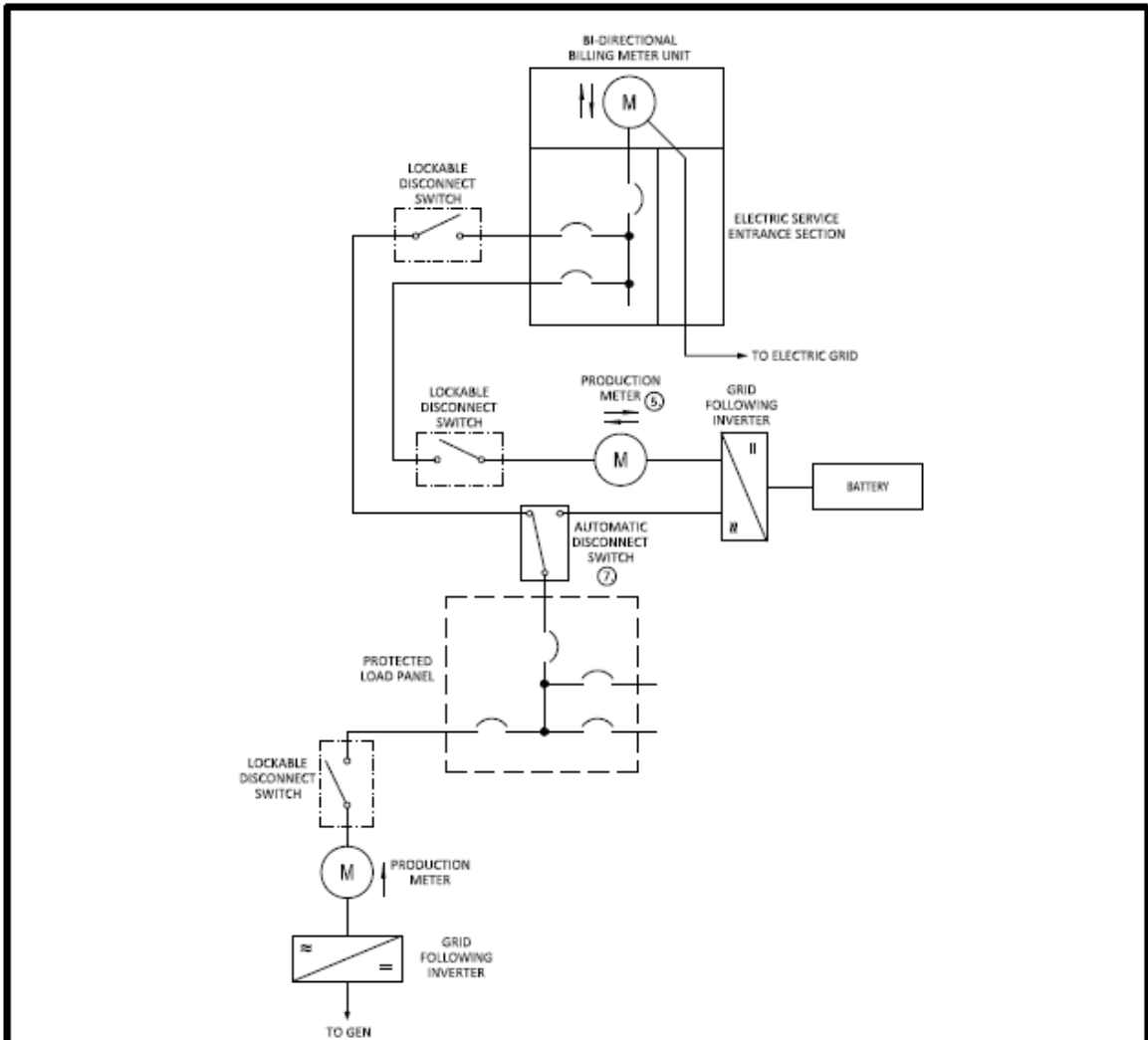
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**GEN AND/OR BATTERY
CONFIGURATION 6**

**DER STANDARDS
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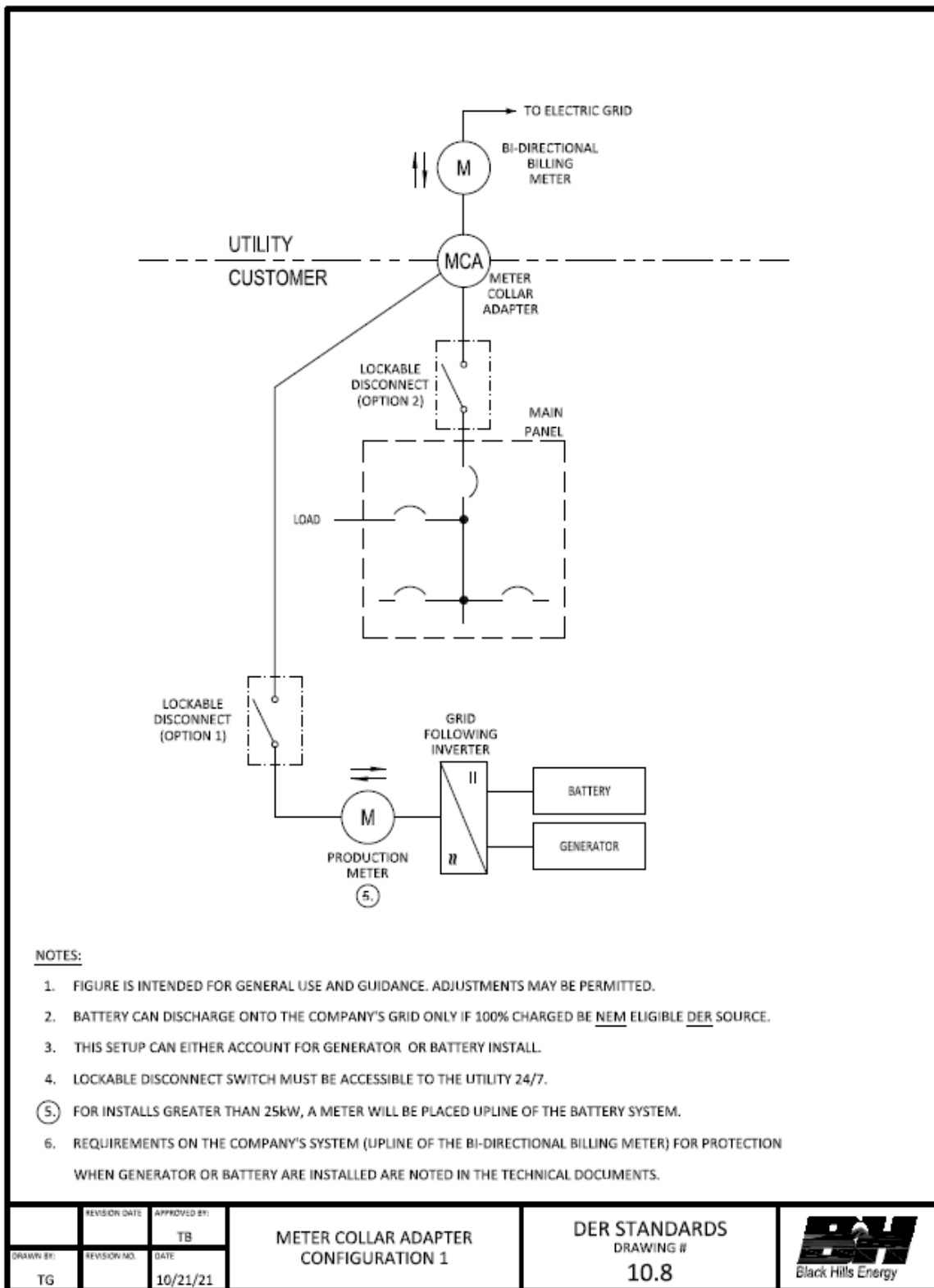




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13.0 TYPICAL DATA POINTS ASSOCIATED WITH CUSTOMER EQUIPMENT

For more information about telemetry, see Section 8.3.

| Typical Data Points Associated with Customer Equipment | | | | |
|--|------|--------------|---------|---------|
| SCADA Name | Type | Control Type | 0 State | 1 State |

| | | | | |
|-----------------------------|--------|--------|-------------|--------------|
| Unit Connection Status | Status | T_IND | Open | Close |
| Battery Charging Indication | Status | T_IND | | |
| Operational State of Charge | Status | T_IND | | |
| Device Status | Status | T_I&C | Open | Close |
| Device GND Trip | Status | T_I&C | Normal | Blocked |
| Device Hot Line Tag | Status | T_I&C | On | Off |
| Device L/R | Status | T_IND | Local | Remote |
| Device Battery | Status | T_IND | Normal | Alarm |
| Device AC Power | Status | T_IND | Normal | Alarm |
| Device PH A Target | Status | T_IND | Normal | Alarm |
| Device PH B Target | Status | T_IND | Normal | Alarm |
| Device PH C Target | Status | T_IND | Normal | Alarm |
| Device GND Target | Status | T_IND | Normal | Alarm |
| Device Transfer Trip | Status | T_IND | Normal | Alarm |
| Device GEN Side Trip | Status | T_IND | Normal | Alarm |
| Device LN Side Trip | Status | T_IND | Normal | Alarm |
| Device Comm | Status | T_IND | Normal | Alarm |
| Device Target Reset | Status | T_CTL | Reset. | |
| Device Reclosing | Status | T_I&C | Non-Reclose | Auto-Reclose |
| Device Recloser Lockout | Status | T_IND | Normal | Alarm |
| Device RLY 51 Diag | Status | T_IND | Normal | Alarm |
| Device MW | Analog | T_ANLG | | |
| Device MVAR | Analog | T_ANLG | | |
| Device IA | Analog | T_ANLG | | |
| Device IB | Analog | T_ANLG | | |
| Device IC | Analog | T_ANLG | | |
| Device IGND | Analog | T_ANLG | | |
| Device VA Load | Analog | T_ANLG | | |
| Device VB Load | Analog | T_ANLG | | |
| Device VC Load | Analog | T_ANLG | | |
| Device VA Source | Analog | T_ANLG | | |
| Device VB Source | Analog | T_ANLG | | |
| Device VC Source | Analog | T_ANLG | | |
| Device Ph A PF | Analog | T_ANLG | | |
| Device Ph B PF | Analog | T_ANLG | | |
| Device Ph C PF | Analog | T_ANLG | | |
| Device IA Fault | Analog | T_ANLG | | |
| Device IB Fault | Analog | T_ANLG | | |
| Device IC Fault | Analog | T_ANLG | | |
| Device IGND Fault | Analog | T_ANLG | | |
| Solar IA | Analog | T_ANLG | | |
| Solar IB | Analog | T_ANLG | | |
| Solar IC | Analog | T_ANLG | | |
| Solar MVAR | Analog | T_ANLG | | |

| | | | | |
|-------------------|--------|--------|--|--|
| Solar MW | Analog | T_ANLG | | |
| Solar MWh | Analog | T_ANLG | | |
| Battery IA | Analog | T_ANLG | | |
| Battery IB | Analog | T_ANLG | | |
| Battery IC | Analog | T_ANLG | | |
| Battery MVAR | Analog | T_ANLG | | |
| Battery MW | Analog | T_ANLG | | |
| Battery Storage % | Analog | T_ANLG | | |

14.0 REVISION HISTORY

This Interconnection Manual is filed with the Colorado Public Utilities Commission and is available for public search in Misc. Proceeding No. 21M-0468E at the following URL:
<https://puc.colorado.gov/>

This Interconnection Manual is posted on the Black Hills Energy website at the following URL:
www.blackhillsenergy.com/services/electric-services/compliance

| Rev. | Revision Date | Description | Revised By |
|------|---------------|--------------------------------|---------------|
| 0.0 | 28-Oct-2021 | New Document (Initial Version) | Todd Bockorny |
| | | | |