SAFETY, INTERFERENCE
AND
INTERCONNECTION GUIDELINES
FOR
COGENERATORS, SMALL POWER PRODUCERS
AND
CUSTOMER-OWNED GENERATION

PUBLIC SERVICE COMPANY OF COLORADO

d/b/a

XCEL ENERGY

AUGUST 6, 2020

SAFETY, INTERFERENCE AND INTERCONNECTION GUIDELINES FOR COGENERATORS, SMALL POWER PRODUCERS AND CUSTOMER-OWNED GENERATION

SAFETY, INTERFERENCE AND INTERCONNECTION GUIDELINES FOR COGENERATORS, SMALL POWER PRODUCERS AND CUSTOMER-OWNED GENERATION

1.0 INTRODUCTION

1.1 GENERAL

Process

The Colorado Public Utilities Commission (CPUC) 4 CCR 723-3 Rule 3667 sets the process and timelines for an interconnection application, review, testing, and approval, see Section 13 links. Rule 3667 directs the Company to provide any additional interconnection standards not provided in Rule 3667. This Manual, along with the tariffs and the Xcel Energy Standard for Electric Installation and Use, address this requirement. Company Tariff Sheets P1-P6 provide the Small Power Production and Cogeneration Facility Policy. Rule 3667 applies to all electrical resources regardless of energy source and include storage. These sources are distributed energy resources (DER) and are generally referred to in this manual as distributed generation (DG).

This Manual primarily addresses the technical requirements of interconnection but does provide some discussion, guidance, and additional information regarding the interconnection process. <u>CPUC Rule 3667 remains the final authority</u>. *The parties can mutually agree to deviations, time extensions, etc. from those stated in the rules and the Interconnection Manual.* The rules provide for three levels of review complexity. Section 14 contains process flow charts to help the user understand the overall application, review, testing, and approval process of the three review levels as specified in 3667. Unless specifically stated otherwise, the requirements in this document apply to continuous parallel operation of interconnected Customer generation.

This manual represents the Company requirements, tariffs, and CPUC rules as of the cover page date. The distributed generation industry and the associated rules and tariffs are changing faster than has historically been the case. All parties are on a learning curve on how to integrate higher DG penetrations. While periodic updates will be made to the manual, some variations will occur between updates and those tariffs, rules, etc. *at the time of application will govern*.

The three review levels are:

<u>Level 1 (Simplified Interconnection</u>) - For Certified Inverter-based Generating Facilities with a power rating of 10 kilowatts (kW) or less on radial, or Network Systems, under certain conditions (see Section 5.16).

<u>Level 2 (Fast Track)</u> with or without Supplemental Review - For Generating Facilities using certified interconnection equipment that pass certain specified screens and have a power rating of 2.0 megawatts (MW) or less.

<u>Level 3 (Full Interconnection Study)</u> - For Generating Facilities that have a power rating of 10 megawatts (MW) or less and do not qualify for the Simplified or Fast Track processes.

Installations over 10 MW are covered by the CPUC 3900 Rules.

The CPUC 3900 Rules derive from the original Public Utility Regulatory Policy Act (PURPA) interconnection rules. The 3900 rules are not as structured for time lines and specific review process steps as the 3667 rules. The CPUC 3667 Full Interconnection Study Rules provide the basic structure and steps that are appropriate to use as a starting point for over 10 MW installations. The 10 kW-10 MW Application Form is the starting point for the application process. The Full process is similar to the FERC SGIP (2006) (Federal Energy Regulatory Commission Small Generator Interconnection Process). The FERC SGIP is a suitable alternative process for the larger generation faculties. The Company and the Customer should mutually agree upon the process during the application phase of the project.

The Renewable Energy Standard (RES) rules, CPUC 3650-3666, address rates, rebates, etc. for those DG facilities that qualify under the RES rules. Rule 3900 references the process rules in 3667 for 0-10 MW PURPA Qualified Facilities (QFs). Rule 3900 applies to QFs rated 10 MW and less for aspects other than the interconnection process. This document is a companion to the RES rules and the areas that are different under the PURPA rules are not discussed. For non-technical matters, careful attention must be exercised for DG interconnection applications that do not qualify under the RES rules.

CPUC Rule 3664

CPUC Rule 3664 addresses the Renewable Energy Standard Net Metering eligibility and requirements.

Definitions

Some of the terms used in this document and the CPUC Rules are defined in the Definitions Section 11. These terms are intended to carry the *same meaning as used in the CPUC Rules* and in the Institute of Electrical and Electronic Engineers (IEEE) Standard 1547 (2003). This standard and other referenced standards are listed in Reference Section 12. The newest version of each standard is the version that is to be used.

Technical Standards

The CPUC 3667 Rules require the use of IEEE 1547 (2003) and 1547.1 (2005) for the technical requirements, interconnection equipment certification, and commissioning testing. This document is intended to provide discussion, summarization, and clarification of these standards for use under the CPUC 3667 Rules and for situations that are not explicitly covered in the IEEE standards. This document provides the additional details to extend the IEEE standards to situations not explicitly covered. The IEEE standards and CPUC 3667 Rules do not address telemetry, metering, and other details necessary to interconnect successfully. Additional references that may be of use are listed in Section 12.

IEEE 1547 and 1547.1 set the performance requirements for certifying interconnection equipment.[1] UL 1741 requires a number of safety and use aspects to be demonstrated in addition to the technical aspects.

For the purpose of this document, the term "Customer" will be used to refer to the entity that proposes to interconnect a small generation facility to the Company's electric distribution system. The small generation facility may be identified in Company tariffs, this manual, and CPUC rules, by other terms such as cogenerators, qualifying facilities (QFs), small power producers, non-utility generators (NUGs), customer-owned generators, distributed generation (DG), distributed energy resource (DER), and electric storage facilities. "Customer" is the same as the (CPUC) 3667 term "Interconnection Customer." The term "Company" will be used to refer to Public Service Company of Colorado, d/b/a Xcel Energy.

This document does not address all of the nuances and complexities involved in designing an interconnection protection scheme. Extensive guidance can be found in the IEEE 1547.2 Guidelines. The minimum requirements for distribution interconnected generation to safely and reliably interconnect to the Company power grid are stated in this document. These requirements are meant to *protect the Company and its other customers*. The Customer is responsible for the overall safe and effective operation of *their* generating facility. The Customer is responsible for designing their own protection scheme and should consult an expert in the field of system protection for distributed generation. The typical relaying one-line diagrams contained in this document illustrate interconnection relaying to *protect the Company*. IEEE 1547.2, Appendix A provides additional discussion and typical one-line diagrams.

Screening Philosophy and Small Unit Compliance

The CPUC 3667 Rules and FERC SGIP are based on expediting the review of interconnections when size, type, and circumstances are such that detailed studies are not needed. The "screens" in the rules are meant to identify those combinations that can be declared safe for interconnection with only brief review and minimal or no utility involvement in commissioning testing. The availability of national

[1] This includes the amendments in IEEE 1547a and 1547.1a.

standards, such IEEE 1547, recently updated national codes, such as NEC, and type tested interconnection products, such as certified inverters, make this a safe and expedited practice.

Most small installations are relatively standardized, will pass the Simplified screens, and will comply with the balance of this document. The statements most relevant to these small installations are underlined to help facilitate the reviews of small, certified installations.

With few exceptions, photovoltaic installations rated 10 kW or less will pass the Simplified screens (Level 1 Review). Any 10 kW or less installation that requires a utility side modification must be reviewed under the Fast-Track process (Level 2 Review). Inverters manufactured and/or sold in the USA are type-tested, certified inverters. Today, many small wind generation units use certified inverters and will pass the Simplified screens also. This means that, unless there are high penetrations[2] of these 10 kW or less units or other generation on a segment of a feeder, they probably will qualify for the Simplified review and approval process. If a unit passes the Simplified review, it should comply with the balance of this document's technical aspects.

Units that pass the screens for the Fast Review will likely comply with the technical aspects of this document. Most large units will not pass the screens. *The primary use of this document is for addressing the requirements and needs of these unique applications that require the additional review of the Level 3, Full Review.*

Smart Inverter Policy

Inverters that have capabilities beyond the functionality needed to meet IEEE 1547 (2003) are considered to be Smart Inverters. As long as the inverter can be certified under the present IEEE 1547.1 (2005) standard, the functionalities compatible with certification may be used for certified interconnections.[3]

Some abilities considered smart inverter abilities may be present but disabled. The additional abilities are to remain disabled unless the Company directs these abilities are to be enabled. As standards evolve, certification of advance smart inverter functionalities will become available. Some inverters will accommodate programming upgrades to become compliant with the advanced certification. Upgrading to certified smart inverter status when it becomes available is desirable.

Final Authority

Customers and Company personnel may be guided by this document when planning installations of distribution-interconnected generation. *The final authority remains with the requirements of IEEE 1547 and the CPUC 3667 Rules.* 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 1547 standard. Customers should discuss project plans with the Company's Engineers before purchasing or installing any equipment to ensure that compatible equipment is acquired.

FERC Jurisdictional Units

Some distribution connected generation units may be classified as FERC jurisdictional[4] units. These facilities must apply, be reviewed, and be approved according to the 2014 version of the FERC Small Generator Interconnection Procedures (SGIP) and use the Small Generator Interconnection Agreements (SGIA). The SGIP and SGIA do not specify the technical interconnection requirements. The Customer will be reviewed in accordance with the *technical requirements of the Colorado rules and this manual.*

[2] High penetration is the term used in this manual when the combined DG on a line segment or feeder can produce reverse power flow during minimum load periods.
[3] As of the date of this manual, the CPUC rule 3667 (h) (A) defines certified as conformance with IEEE 1547 (2003) and 1547.1 (2005). The Smart Inverter Policy will be kept compliant with the CPUC rules.
[4] FERC jurisdictional status generally applies to units with a contract to sell to a non-host utility party via the transmission system. DG that sells output to the host utility is generally State jurisdictional.

1.2 POLICY ON INDEPENDENT GENERATION

The Company will allow any Customer, as permitted under CPUC Rules and Company tariffs, as approved by the Commission, to operate generating equipment in parallel with the Company electric distribution system whenever this can be done without undue risk or adverse effects to the general public or to Company equipment or personnel. Certain protective devices (relays, circuit breakers, etc.) must be installed at any location where a Customer desires to operate generation in parallel with the Company's electric system. These requirements are determined in accordance with the CPUC 3667 Rules and the applicable standards and codes. The purpose of the protective devices is to promptly disconnect a Customer's generating equipment from Company's system whenever faults or abnormal operating conditions occur. Other modifications to the Company's electrical distribution system configuration or protective relays may be required in order to accommodate distribution connected generation. Large facilities will often require distribution system modifications including the extension or rebuild of a feeder and the addition of interrupting devices.

1.3 GENERATION SOURCES

The Colorado Rules and this document are based upon the generation technology used, *not upon the fuel or energy source that is utilized*. This includes energy storage devices, such as batteries, when providing energy. *The term "generator" also applies to energy storage devices as used in this document*. The generator output for connection to the Company's system must be 60 Hz sinusoidal alternating current at a standard Company voltage (see Section 2.1) and phase rotation. Customer should verify phase rotation, feeder type (3 wire or 4 wire), and voltages with the Company before purchasing any equipment. It is Company policy that all sources that operate in parallel with the utility system shall have an interconnection review.

A Customer may operate the generator: a) In parallel with the Company's electric system or b) As a separate system with the capability of load transfer between the two independent systems. Neither the CPUC 3667 Rules nor IEEE 1547 specifically cover the load transfer mode requirements. The transfer mode requirements are based upon these rules and standards but generally have less stringent requirements than for continuously parallel operation. Each continuously paralleling mode of operation requires a signed interconnection agreement.

Some transfer modes require a signed interconnection agreement. See the following for which situations require an Interconnection Agreement (IA):

- IA will be required for all ≥ 1 MW
- Primary metered customers with generation
- Large retail customers with generation on shared secondaries

<u>IA may be required for:</u>

- Large retail customers with generation on large dedicated secondaries
- Medium customers with generation on shared secondaries
- Systems that may create excessive voltage rise or flicker due to high generation to load ratios or proximity on the feeder
- Customer supplied from a secondary grid network or a spot network with more than one customer

The technical requirements for these modes of operation are outlined below.

1.4 SEPARATE SYSTEMS

A separate system is defined as one in which there is no possibility of connecting the Customer's generating equipment in parallel with the Company's 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.[5] If a Customer has a separate system, the Company may require verification that the system meets the non-parallel requirements. The Company may elect to field inspect the transfer scheme. The Company will not be responsible for approving a Customer's generation equipment and assumes no responsibility for its design, operation, or effects on Customer's loads (see Liability Section 1.7). *If the transfer switch is capable of closed transitions, the system will be subject to the closed transfer operation criteria below.*

1.5 PARALLEL OPERATION

A parallel system or parallel generation is defined as one in which a Customer's generation can be connected to the Company's system. A transfer of power between the two systems is a direct and often desired result.

Electric problems are principally short circuits, grounded conductors, and broken conductors. These fault conditions require that the equipment involved be de-energized as soon as possible because of hazards they pose to the public and to the operation of the system. A parallel generator must have adequate protective devices installed to sense trouble on the utility system and promptly disconnect from the utility system.[6]

Parallel generation can also cause another condition known as "accidental isolation" or "islanding" in which a portion of the Company's load becomes isolated from the Company's electric source but is still connected to a Customer's generator(s). Unless directly approved by the Company, this mode of operation is not allowed. In this islanded condition, the isolated generation system may continue to operate independent of the Company's system but probably with abnormal voltage and/or frequency. Accidental isolation or islanding is avoided by having the correct protective relaying installed by the Customer as required under IEEE 1547. The protective devices and other requirements imposed by the Company in the following sections are intended to disconnect the parallel generator when trouble occurs. These requirements are minimal for a small installation but increase as the size and complexity of the generation increases.

1.6 AUTOMATIC THROW-OVER SERVICE WITH PARALLEL GENERATION

The Company prohibits the use of continuous parallel generation (greater than 2 minutes) behind Company owned primary voltage Automatic Throw-Over (ATO) equipment. Closed-transfers of less than 2 minutes duration may be permitted for small generators under some conditions.

The Company may, at its sole discretion, allow *inverter based* distributed generation behind a Company owned ATO if the aggregated inverter based distributed generation rating is 50% or less than the Customer's minimum load. The Company may, at its sole discretion, allow rotating machine distributed generation behind a Company owned ATO if the aggregated inverter based distributed generation rating is 10% or less than the Customer's minimum load. All generation that operates in parallel with the Company is subject to the requirements of this manual.

If the Customer chooses to operate continuously parallel generation behind a *Customer* owned ATO equipment, the Customer assumes all responsibility for any reliability issues, including electrical power outages and damages resulting from concurrent use of parallel generation and ATO service.

[5] An Automatic Throw-over Switch (ATS) that is incapable of make-before break transitions qualifies as separate system.

[6] As long as the timely disconnection requirement is met, the DG may continue to supply the Customer's load. If this operating mode is used, suitable equipment is required to synchronize and connect back to the distribution system once normal feeder operation has resumed.

1.7 LIABILITY AND INSURANCE

Please refer to the Interconnection Agreement for the size and class of interconnection being considered for detailed liability and insurance language. Further information is available in the CPUC rules. PURPA units are addressed in Rule 3950 (>10 MW). RES (0-10 MW) units are addressed in 3667(e)(XI), and 3667(j)(VI)-(VIII).

2.0 COMPANY SYSTEM INFORMATION

2.1 VOLTAGE

The Company's most common primary distribution voltages are 12.47 kV, 13.2 kV, and 24.94 kV; other voltages are sometimes used in specific areas. Virtually all of the distribution circuits are "effectively grounded" (see Section 2.3) and are used to provide four-wire distribution (phase to neutral) connected loads. Contact the Company for information on the specific circuit that will serve the Customer's proposed facility. 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. The three-phase voltage-to-neutral unbalance is targeted to be under 3% but may be higher during emergency conditions and contingency configurations due to maintenance or outages.

2.2 CIRCUIT RESTORATION

Because most short circuits (faults), especially on overhead lines are of a temporary nature, it is the Company's practice to automatically reclose our circuit breakers on most distribution lines. The initial reclose delay is typically 2 seconds. The company utilizes sectionalizers, reclosers, and distribution automation for both overhead and underground feeders. These also employ an automatic delayed reclose. A number of substations are tapped to the transmission lines and are subject to transmission line reclosing. Most tapped transmission line reclosing has a 1.5 - 2 second delay. 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 is not adequate or quick enough to ensure generator separation before a Company delayed reclose. This situation is more likely where voltage and/or frequency ride-through are employed such as permitted under IEEE 1547a. *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.* In addition to high transient torques, transient voltages up to 3 per unit can be generated. <u>This is seldom an issue for *smaller*, inverter-based interconnections.</u>

To address the hazards associated with out-of-sync reclosing, voltage-supervision-of-reclosing (VSR), also referred to as hot-line reclose blocking (HLRB), will be required whenever a feeder or line segment may have reverse power flow, at least part-time, during the year. Line segment minimum load usually must be estimated. If the estimate accuracy confidence level is low, a higher ratio than 2 may be required. To ensure safe recloses, VSR is normally required whenever the ratio of minimum load to generation is less than 2. The presence of substantial size rotating generators, motors, and capacitors on a feeder or line segment will require VSR if the minimum-load-to-generation ratio is less than 2. *Where out-of-sync reclosing may cause conditions that will damage other customers, HLRB, Transfer-Trip, or other measures <u>may be</u> required.* Especially for large DG, these requirements may also apply to the transmission line that supplies the substation. This is at Customer cost.

2.3 EFFECTIVE GROUNDING

The Company operates an effectively grounded system, as defined by IEEE standards, on most of its distribution system and requires that Customer generation connected to the Company's system be designed (through the selection of transformers, generator grounding, etc.) so that they contribute to maintaining an effectively grounded system in conformance with IEEE 1547 4.1.2.[7] A generation facility that does not participate in maintaining effective grounding, upon islanding, can cause severe overvoltages to single phase loads, resulting in equipment damage. IEEE 1547.2 provides additional discussion on the importance of and methods to address effective grounding. <u>Smaller, single-phase inverter based generation facilities are excluded from this requirement.</u>

This Section is directed at Customers that operate for extended parallel with the Company's distribution system. Effective grounding limits the voltage rise on unfaulted phases during single-line-to-ground fault conditions and some line switching situations. Inverters must achieve the equivalent limitation of overvoltages as discussed under "Inverters" below.

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

Direct connected rotating generators must comply with the traditional IEEE grounding standards. To achieve effective grounding, a Customer's system equivalent (Thevenin equivalent impedance) must meet the two criteria given below or otherwise meet a coefficient of grounding of 80%, also see IEEE 32 and IEEE C62.92.2. Note – the effective grounding impedance is always determined with the generator separated from the utility. Momentary fault withstand and continuous current ratings are always determined with the utility and generator connected.

a) The positive sequence reactance is greater than the zero sequence resistance ($X_1 > R_0$).

b) The zero sequence reactance is less than or equal to three times the positive sequence reactance. *The Company requires the ratio to be between 2.0 and 2.5 ($2.0*X_1 \leq Xo \leq 2.5*X_1$) 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 impedance networks, the networks should include impedances for the following: the step-up transformer, generator subtransient reactance (X_d"), neutral grounding reactance on the step-up transformer and/or generator, secondary cable runs greater than 50 feet in length, and the grounding bank. For induction generators, the equivalent of the subtransient reactance should be used. If the X_d" equivalent is not available, the following approximation is usually adequate: X = (Rated Voltage / Locked Rotor Current) ohms. The Customer should submit the grounding device information for approval before it is purchased.

Many different system configurations will meet the effective grounding requirements. Section 18 provides a table of transformer winding configurations and their ability to pass ground referencing through or to act as a ground source. Listed below are some guidelines and restrictions.

a) A grounded-wye/grounded-wye step-up transformer is common. 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. Company supplied three-phase service transformers are grounded-wye/grounded-wye for four-wire systems.

b) A delta (gen)/grd-wye (system) step-up transformer must have a reactor in its grounded-wye neutral connection to meet the Company's requirements for effective grounding or a separate

[7] The term "effective grounding" is used as defined by the IEEE standards regarding restraint of neutral conductor voltage sift away from earth potential for 4 wire power systems. The National Electric Code uses this term to describe ensuring a metallic object or conductor is at earth potential for personnel safety. While these are somewhat related, this section refers to the IEEE definition.

ground bank, *($2.0*X_1 \le Xo \le 2.5*X_1$).* A neutral resistor will cause high power losses and is not recommended. Company does not supply this configuration.

c) A 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 of the generator step-up transformer. The grounding bank's impedance must be selected so that it meets the Company's effective grounding requirements above, and it must be rated to withstand the system fault current and voltage imbalance. This configuration requires a switching device to separate both the generator and ground source during system separation, see Figure 10.4. Company supplied three-phase service transformers are generally delta on the utility side for three-wire systems.

d) Generators 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 since significant generator derating due to unbalanced currents may result.

e) Voltage imbalance on the Company's distribution system may result in substantial current flowing into a Customer's generator(s) or grounding equipment. The Company's operating objective is to keep phase-to-phase voltage imbalance under 1% and phase-to-ground voltage imbalance under 3%. Imbalance may be higher, especially during contingency conditions. The Customer's equipment must be able to withstand allowable voltage imbalances and be able to operate during an imbalance condition. A V_0 sequence voltage of 4% is recommended for determining the continuous imbalance rating. This rating should be adequate for contingency system configurations.

Normal system source impedance data for a given location can be obtained from the Company's Area Engineer. For contingencies and maintenance, field ties are temporarily used and this can change the source impedance and fault duties as seen by a Customer. Normal system source impedance should be obtained before a 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.

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, single-unit, or composite facilities should be checked for effective grounding equivalency. IEEE C62.92.2 directly applies to rotating generation and *cannot* be directly applied to inverters to determine ground referencing equivalency since grid connected inverters operate as a current source, not as a voltage source. Small, single-phase inverter installations are usually exempt from this requirement.

The grounding requirement applies regardless of the energy source providing power to the inverter. The grounding method used needs to be compatible with the step up transformer configuration, see Section 18. For three-phase installations, the phase-to-neutral overvoltages during a single line-to-ground fault must be constrained to avoid exposing the single-phase loads connected on the unfaulted phases to excessive voltage (<130% Ph-N rated voltage). The *equivalent* of a coefficient of grounding of 80% must be achieved, also see C62.92.4. All inverters connected to spot or area networks must be effectively grounded on the secondary side.

The following sizing method meets the grounding requirement. Section 18 provides a table of transformer winding configurations and their ability to pass ground referencing through or to act as ground source.

The grounding device or neutral reactor may be estimated according to the following criteria:

$X_{0DG} = 0.6 \pm 10\%$ p.u. and $X_{0DG} / R_{0DG} \geq 4$

where 1 pu Ω is based on kV^2 / MVA

1) the total MVA rating of the DG Facility (sum of DGITs' MVA ratings) and high side kV rating of the DGIT(s) for Grounding Transformer sizing; or

2) The MVA and high side kV rating of the DGIT for NGR sizing.

3) DG interface transformer (DGIT) MVA rating is assumed to be approximately equal to the generation capacity

4) For inverter based interface, the "0.6" factor is a conservative approximation

5) DG interface transformer (DGIT); neutral grounding reactor (NGR)

6) Assume V_0 = 4%. NGR or transformer should have a continuous current rating based on $I_{0GB} = (4\%\ V_0) / X_{0DG}$.

7) Momentary fault withstand must have a time rating of 5 seconds or more with 10 seconds recommended.

Many three-phase inverters will not meet the grounding requirement. Some manufacturers employ an internal high resistance between the transformer's internal wye and the neutral or ground connection, which does not qualify as ground referencing. Some manufacturers connect the inverter transformers in a delta configuration. The presence of a neutral connection on the inverter *does not* ensure a grounded-wye configuration. If the inverter does not provide adequate ground referencing, either a small grounding bank will be needed, see Figure 10.3, or grounding with a separate wye-grounded/delta transformer with neutral reactor will be needed, see Figure 10.4. See Section 2.5 for discussion of three-phase installations using single-phase inverters.

An inverter with a delta/grounded-wye matching transformer will experience imbalanced current due to distribution system voltage imbalance. This may limit the inverter output capacity or result in overcurrent shut-downs during distribution system ground faults. A solid ground connection without a suitable neutral reactor *is not recommended*. Use of a neutral resistor is not recommended due to the ongoing elevated losses. A neutral reactor will reduce the imbalance current, operation issues, and losses. A grounding transformer avoids these issues and is *the recommended approach*.

"Transformerless" inverters rated 100 kW or less may be exempted by the Company Engineer at their sole discretion. Above 100 kW, a separate ground referencing source must be provided.

Generation technologies other than those discussed above may come into use. The same principles will apply to them. The energy source interconnected to the Company's effectively grounded distribution system must provide effective ground referencing.

Multi-Inverter Installations

Larger facilities are often comprised of multiple inverters, each with its own PV panels. For medium size installations with a secondary voltage PCC, a single ground referencing device may be installed to handle the entire facility. It can be sized in the same manner as described above. The sum of all of the included inverter AC nameplate ratings is used in the formula along with voltage at the location where the ground reference will be attached.

This same approach is used for large PV farms. The ground reference is often located at the medium voltage DG bus that connects to the PCC. The voltage to use in the formula is the medium voltage location rated voltage. The grounding method used needs to be compatible with the step-up transformer configuration, see Section 18.

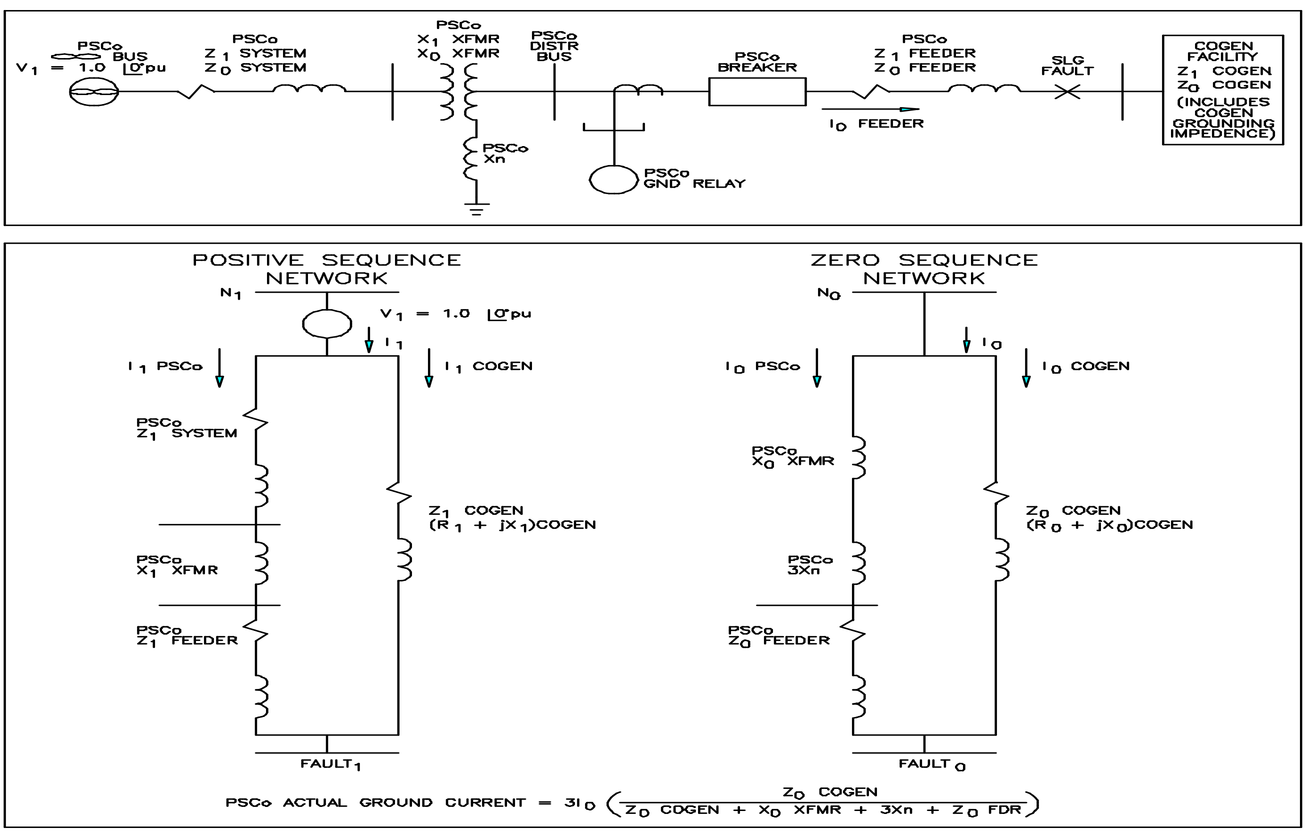
Company Ground Relays

When customers install ground sources as discussed above, the Company's ground overcurrent relays located at the substation and on distribution feeders will be de-sensitized during a single-line-to-ground fault when a Customer's generator(s) is operating in parallel. If the Customer contributes more than 10% to a feeder line-to-ground fault, corrective measures become likely. This is rarely an issue when the generation facility uses inverters. Refer to Figure 2.3.1 when calculating the ground fault current before and after the addition of the Customer's generator(s). When the Customer's grounding contribution is relatively large, the Company may require additional feeder protection equipment, at the Customer's expense, to ensure a reliable and secure system configuration is maintained. The same loss of sensitivity for three-phase faults is possible especially with large rotating generation.

Grounding Bank Protection

When ground referencing transformers are installed to comply with the requirements, the protective relaying design and device ratings will be reviewed. The protection must be compliant with NEC Article 450.3, 450.5(A), or NESC as is applicable. The generation source must be off-line or be tripped off-line if the ground referencing transformer is unavailable or fails. If a protection scheme is AC powered, it shall be designed to minimize accidental disabling. The NEC required grounding transformer overcurrent protection should have enough time delay to coordinate with the utility protective relaying. Protection with time delay should have a time delay that places the tripping characteristic at the grounding transformer's maximum current and withstand time rating. Protection schemes that remove ground referencing during times that the generator is off line will be reviewed to ensure ground referencing is in service whenever the generator becomes active.

The following diagrams summarize the effective grounding methodology:



PSCo EFFECTIVE GROUNDING CALCULATIONS
Figure 2.3.1

2.4 NON-EFFECTIVELY GROUNDED DISTRIBUTION CONNECTED PRODUCERS

At the sole discretion of the Company Engineer, a generation facility under 100 kW may be other than effectively grounded if it can be shown that when the generator is islanded from the Company and is still generating power, the kW load that will be served from the generator during the islanding condition will at all times be at least three times greater on each phase than the generator's per phase kW rating (MLGR). In general, a facility under 100 kW that passes the Screens for Simplified Interconnection or Fast Track interconnection will qualify for the ungrounded operation option. All inverters connected to spot or area networks must be effectively grounded on the secondary side.

2.5 SINGLE-PHASE INVERTERS

Three-phase DG facilities comprised of single-phase inverters must comply with NEC (2014) 705.40, 42, and 100. This applies whether there is one single-phase inverter per phase or multiple micro-inverters. Upon loss of one phase or one phase of the facility trips, the facility must cease exporting power or sense and separate the generation on all three phases. Any three-phase facility that is large enough to require the use of a grounding bank must sense and totally separate for loss of one or more phases or tripping of one or more DG phases.

Three-phase DG facilities comprised of single-phase inverters shall be designed to produce power that is closely balanced per phase. The same considerations apply to single phase secondary service if inverters are applied hot leg to neutral. Operation that results in unbalanced power production or resulting voltage unbalance in excess of the requirements as stated in the Xcel Energy Standard for Installation and Use shall cease operation until a balance better than the Standard's minimum requirements can be met.

3.0 SYSTEM INTEGRITY

3.1 GENERAL

The interconnection of the Customer's generating equipment with the Company's system shall not cause any significant reduction in the quality of service being provided to other customers. Certified inverters, unless they are malfunctioning or misapplied, will generally comply with the Section 3 requirements. Abnormal voltages, frequencies, harmonics, or 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 a Customer's DG, such DG equipment may be disconnected from the Company's system, as permitted under CPUC 3667 Rules, until the Customer resolves the problem. The Customer is responsible for the expense of keeping the DG in good working order so that the voltage, Total Harmonic Distortion (THD), Total Demand Distortion (TDD), power factor, and VAR requirements are met. IEEE 1547.2 provides additional discussion and approaches for identifying and addressing these Section 3 issues.

3.2 HARMONICS

The Total Demand Distortion (TDD) 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 be kept to a minimum. Under no circumstances may the harmonic current distortion, originating from the DG, be greater than the values listed in Tables 3 and 6 from IEEE 1547[8]. Certified inverters that are operating properly will meet this requirement.

[8] IEEE 1547 – 2003; IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

Table 3—Maximum harmonic current distortion in percent of current (I)a

Individual harmonic order h (odd harmonics)b	h < 11	11 ≤h < 17	17 ≤ h < 23	23 ≤h < 35	35 ≤h	Total demand distortion (TDD)
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

a I = the greater of the Local EPS maximum load current integrated demand (15 or 30 minutes) without the DR unit, or the DR unit rated current capacity (transformed to the PCC when a transformer exists between the DR unit and the PCC).b Even harmonics are limited to 25% of the odd harmonic limits above.

Table 6—Maximum harmonic voltage distortion in percent of rated voltage

Individual harmonic order	h < 11	11 ≤h < 17	17 ≤ h < 23	23 ≤h < 35	35 ≤ h	Total harmonic distortion
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

In addition, any interference with other customer's equipment or communications caused by Customer's harmonics in excess of federal, state, and local codes *will be resolved at the Customer's expense.*

3.3 DISTRIBUTION LEVEL VOLTAGE

Operation of the Customer's generator(s) shall not adversely affect the voltage stability of the Company's system. The facility shall not actively regulate the feeder voltage[9] or cause it to go outside of acceptable limits (ANSI C84.1[10] Range A), see IEEE 1547 section 4.1.1; "Adequate voltage control shall be provided by all Customers to minimize voltage deviations on the Company's system caused by changing generator loading conditions." *Fixed power factor or VAR controllers will need to be utilized for medium and large generation facilities and some small facilities. Applicants that oversize energy sources to maximize DG rated output may be subject to reduced generation if power factor or VAR control is required as a condition for approval to limit voltage rise to acceptable levels.*

Default Power Factor

All new generation interconnections, including inverter based generation, shall operate under power factor control set at a default value of 0.98 Leading power factor (absorbing vars) unless otherwise directed by the Company Engineer.

All new interconnection inverters shall be able to accommodate power factor settings down to 0.90 Leading and Lagging. The customer is responsible for either upsizing the inverter to be adequate to operate at 0.95 power factor while producing the desired maximum real power or accept any resulting real power production reduction that may occur during peak insolation periods.[11]

[9] IEEE 1547a - 2014 allows active voltage regulation by *mutual* agreement.
[10] ANSI Range A for most applications is nominal voltage ± 5%. The standard includes some cases where other limits apply.
[11] These limits subject to change based on requirements established in the IEEE P1547 update.

If an existing inverter based installation needs to replace its inverter, the replacement shall be capable of and be set at 0.98 Leading unless directed otherwise by the Company Engineer. An existing failed inverter may be repaired and reinstalled.

Voltage rise and voltage flicker are the primary limiters of added generation. The power factor requirements will improve power quality for all, reduce mitigation costs for interconnections, and will increase the maximum generation penetration that can be hosted. If the leading power factor (absorbing vars) operation is not used or is inadequate, feeder reconductoring, new feeders, or other high cost mitigations are likely to be required.

The Company is obligated to maintain a near unity power factor at its transmission points of delivery, see "Xcel Energy Interconnection Guidelines for Transmission Connected Customer Loads" Section II.I, Minimum Power Factor Requirements. If a medium to large Customer facility is operating at a non-unity power factor, the Company may need to install a capacitor bank in or near the distribution substation to supply the DG facility's reactive power consumption, at the Customer's cost, in order to ensure meeting the Company's high voltage delivery point power factor obligations.

Secondary Circuit Limitations

Existing secondary circuits are designed and installed to provide service up to 480 volts for typical loads (power flow) and load shapes. If DG is installed that is rated to provide the maximum allowed annual energy, the midday power produced by the PV could be several multiples of the maximum load power flow in the solar noon period. This may require replacing part or all of the overloaded secondary wiring back to the service transformer.

If the secondary serves multiple Customers with PV, up-sizing the secondary becomes more likely and may include replacement of the service transformer or splitting the secondary services to be supplied by two or more service transformers. Such mitigations are chargeable to the Customer[12]. This includes all installations including under 10 kW residential PV.[13] The up-sizing, including splitting services onto separate service transformers, may also become necessary due to excessive voltage rise or flicker.

Synchronous Generators

Most synchronous generation units will be required to operate in power factor mode, usually set at 0.98 Leading power factor. Some installations, mostly large installations, may require power factor control set to a value of 0.95 Leading (absorbing vars) to counter a voltage rise caused by the DG's exported power.

Induction Generators

For induction generators, including double-fed induction generators, the generation units must be mechanically brought to near synchronous speed before connecting to the system. Double-fed induction generators that are capable of self-excitation should use this mode to synchronize and connect. When connecting induction generators to the system, some voltage fluctuations will occur due to magnetizing inrush current. Voltage fluctuations will be measured at the interface or PCC between a Customer's system and the Company's system.

Voltage fluctuations shall comply with the requirements of the Voltage Flicker section. A voltage drop in excess of the standard may be acceptable after consultation with the Company, but a Customer is responsible for any associated damages to equipment of the Company other customers. It is suggested that Customers review and comply with the Computer Business Equipment Manufacturer's Association (CBEMA) curve detailed in IEEE/ANSI Standard 446 Section 3.11 (esp. fig. 4), for typical computer sensitivity to voltage disturbances. Complaints are rare if the operation complies with IEEE 446 and 519.

[12] As with all mitigations, the full burden of mitigation cost falls on the last to apply Customer that exceeds what can be accommodated without mitigations.

[13] The 10 kW and under Simplified review process does not allow system modifications. If modifications are needed, the review must be under the Level 2 process.

Small induction generation units may be allowed to operate with minimal power factor correction such as at 0.95 Leading (absorbing vars). Medium to large induction units must have power factor correction capacitors controlled to bring the unit power factor lower than unity but higher than 0.95 Leading when operation is above one quarter rating.[14]

Inverter Connected Generators

Distribution generation units that interconnect using an inverter are expected to operate at a default 0.98 leading (absorbing vars) power factor. Large inverter units or large composite groups of smaller inverters will need to be capable of operating at power factor set points in the range of 0.95 leading (absorbing vars) to unity. Additional voltage and power factor requirements may be placed on very large single or composite inverter installations similar to the requirements discussed under synchronous generators. Large inverter matching transformers may introduce significant energization voltage dips. These dips must be within the flicker curve limits.

Voltage Variations Including Flicker

Voltage fluctuations within the normal operating voltage band can be classified into three categories. A sudden step change in voltage such as a motor starting, a load tripping, or generation tripping is referred to as a rapid voltage change (RVC). Ongoing voltage variations that cause brightness variations in lighting intensity, which people regard as irritating or annoying, is referred to as flicker. Equipment compatibility limits, or the tolerance of equipment to withstand voltage fluctuations, needs to be considered when determining study thresholds. The interconnection review examines the impact of all three categories.

Distribution level voltage flicker caused by distributed generation is often a limiting factor with high penetration. There are various events that can trigger most or all DG on a feeder to trip simultaneously. The instantaneous total step-voltage-change (RVC) threshold of concern is 2.5% for this condition. After such an event, certified inverters will all resume operation after the default 5 minute delay. To mitigate the restart voltage swing, staggered restart time delays or maximum ramp rate limiting (as requested by the Company Engineer) may be required. The maximum allowed step-change, such as when a single facility is tripped, on primary or secondary voltage, from one distributed generation facility is 2%.

The utility distribution system employs multiple mechanical voltage regulation devices such as switched capacitors, line regulators, and transformer load tap changers (LTC). The equipment compatibility limit at the device of concern is a 1.5% voltage fluctuation that occurs as part of ongoing operations. Regulation deadbands are in the 2-3% range and frequent excursion outside the deadbands cause excessive wear and early failure of the regulating devices. Wind gusts and cloud passage for PV are among the sources that must be compatible with this limit. Wind gusts and cloud passage causes smaller voltage variations than the generator tripping. The interconnection review will use a 75% of tripping variation to approximate this smaller impact. 75% of 2% tripping is the 1.5% equipment compatibility limit.

When the limits described above are reached, additional interconnections cannot be allowed without further mitigations. Such mitigations are often expensive, such as reconductoring or building another feeder. Operation at 0.98 Leading (absorbing) power factor, and in some cases down to 0.95, may provide adequate mitigation. The same voltage flicker considerations apply to shared secondary interconnections, such as residential rooftop PV. Reconductoring the secondary wiring or splitting the service into two or more separate line transformers at customer expense may be required.

[14] If the var supply exceeds the var needs of an induction generator and any connected load, very high voltages may be generated at separation. The excess vars may come from utility capacitors, generator power factor correction capacitors, or other sources that may be islanded with the generator.

The interconnection review will evaluate these situations. Since these are the result of all of the DG on a feeder and substation[15], the impacts from those already on-line may preclude further interconnections. If a required interconnection mitigation is based on an operational requirement, such 0.98 leading power factor, deviation from the required operation will be considered a breach of agreement. A failure to remedy the situation in a timely manner will be grounds for disconnection.

4.0 GENERAL DESIGN REQUIREMENTS

4.1 CODES AND NERC STANDARDS

A Customer's installation must meet the Public Utility Commission rules for small power production and cogeneration facilities, and all applicable national, state, and local construction, environmental, and safety codes. The Customer must also meet all applicable interconnection requirements of the Western Electricity Coordination Council (WECC).

One or more large generation facilities connected to the distribution of a substation may create operational issues that affect the transmission system to which the substation is attached and may trigger a separate transmission system impact review. This review is likely to increase total study time and cost. Even though these interconnections are 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 mitigations to the transmission system, such as the use of transfer trip. The Company Engineer will work with the Customer to communicate with and comply with the requirements of the transmission provider (see CPUC rule 3667 (e) (IX)). In most cases, the transmission provider will be Xcel Energy.

For all generation units, including distribution connected units above 10 MVA, over/under frequency protective (device 81 O/U) relaying shall be set to coordinate with the area automatic underfrequency load shedding program (UFLS). The Western Electricity Coordination Council WECC UFLS program and the North American Reliability Corporation (NERC) reliability standard PRC 006 govern the requirements. Standards that are undergoing update reviews will likely be changed to require this UFLS coordination on all distribution connected generation in the future. Generation facilities must not separate from the system until all underfrequency load shedding steps have operated. The lowest load shedding step is 58.3 Hz, as of this document's publication date. <u>It is Company policy that all generation units above 30 kW (300 W if certified to IEEE 1547.1a) shall coordinate with the UFLS unless directed otherwise by the Company Engineer.</u>

The 2014 National Electric Code, NFPA 70, contains an article that restricts the size of an inverter based interconnection into a shared panelboard. Article 705.12(D)(2) states 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." *If compliance is not determined prior to submitting the interconnection application, significant delay may occur during commissioning.*

4.2 PROTECTIVE DEVICES

Protective devices (relays, circuit breakers, etc.) for the protection of the Company's system, metering equipment, and synchronizing equipment must be installed as required by the Company and IEEE 1547 in accordance with the requirements of the CPUC 3667 Rules. The complexity of the protective devices differs with the size, complexity, and location of the generation installation (see Section 5 and Section 10).

---

[15] When a substation bus has multiple feeders with high DG penetration, the flicker impact of the combined feeders' DG will be evaluated. The combined DG flicker at the substation bus may preclude further interconnections even though on a feeder basis it may pass.

For the protective functions required under IEEE 1547[16], the default settings provided in IEEE 1547 shall be used unless the interconnection review indicates some other setting is to be used. The exception is the underfrequency relay setting as discussed in 4.1 above.

Manual Disconnect Switch

A manual disconnecting device, capable of interrupting the rated generator and/or load current, accessible to the Company's personnel, and which can be locked open with a visible open for line clearances, must be provided. The visible open shall be viewable without unbolting covers or assistance from site personnel. The switch must be accessible to the Company personnel without assistance from site personnel. The form of this device will vary with the service voltage and generator capacity.

The manual disconnect switch must be clearly marked with a permanent, weather-proof label, refer to Section 17 for label requirements. For generation 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, clearly labeled map or diagram showing the location of the revenue meter, the switch, production meter, and generation facility. Also refer to the Xcel Energy Standard for Electric Installation and Use, Section 8.

Facilities that do not continuously parallel with the Company's electric system or on-site certified inverter based solar generation 10kW or less with no production meter, supplied by a branch circuit from the customer's panel, may omit the disconnect switch. To qualify as not continuously operating in parallel with the Company's electric system, the Customer's system must be a separate system never in parallel, a high speed transfer, or closed transition limited to a maximum of 2 minutes in parallel. This utility requirement does not preclude any requirement for a disconnect based on NEC and the local code authority.

For generation that is supply side connected, where the point of interconnection (POI) is between the load side of the utility meter and the main panel disconnect, Xcel will enforce Section 2.13.5 item #6 of the Xcel Standard for Electric Installation and Use. This requires that the customers' equipment has a mechanical means to disconnect and isolate equipment from the load-side terminals of the self-contained electric meter socket or instrument transformers (CTs and VTs).

4.3 QUALIFIED PERSONNEL

The Customer must provide the Company with the contact information of the person or persons qualified to operate the facility. This contact information should be a valid, 24/7 for installations over 100 kW, but may be the Customer's listed contact number for small installations.

4.4 DESIGN REVIEW AND DOCUMENTATION

The Customer, in accordance with the CPUC 3667 Rules, 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 system. The Interconnection Application Form specifies most of the information needed for the Company review. For some applications, some additional information may be needed. The specific design documents and test procedures will vary for each facility; however, some general documents for the design review process are outlined below. The information is *tailored to medium to large* installations, especially when the interconnection equipment *has not been certified*. <u>For small installations, especially those using certified interconnection equipment, the documentation needs are minimal *and the in-depth steps below will not apply*.</u>

a) The Customer submits an application as specified in the CPUC 3667 Rules. The Company performs a review and approves the design according to the process specified in the CPUC 3667 Rules for the size, type, and location of the generation package. *A site-plan diagram is required* (see Section 16).

[16] Default IEEE 1547a settings for inverters certified under 1547a.

This package shall include an electrical one-line diagram that identifies basic service voltages, major facility equipment and ratings [generators (gross and net), transformers, breakers, approximate load/station service requirements, etc.], metering, and PCC (electrical and physical locations). **Applications require these two documents.** The Customer should also include any pertinent information on normal operating modes, proposed in-service dates (both initial energization, and commercial operation), etc. In order to avoid any unnecessary costs associated with changes to the design plans, this design package should be submitted prior to the Customer ordering any equipment, or beginning any major, detailed engineering work.

b) The Company will review the design documentation and provide comments back as specified in the 3667 Rules. The Company's comments may include cost estimates, as appropriate, for any modifications to the Company's system required to accommodate the interconnection. The Company will also provide maximum system short circuit data at the PCC if requested by the Customer.

c) Once the final design has been agreed upon, the Customer should provide detailed information on the protective relaying, metering, and control (including sync-check) equipment. This shall be provided on a relaying and metering one-line (and preferably a three-line) diagram for larger non-certified installations. Basic proposed AC and DC schematics or specification of logic should also be provided at this time along with a listing of the proposed specific relays including information on the manufacturer, model number, relay ranges, etc. See Section 5 for additional details on the relaying requirements. If the information is not submitted electronically, the Company requests at least two sets of any design documentation packages. In order to avoid any unnecessary costs associated with changes to the preliminary design plans, preliminary design information should be submitted to the Company prior to the Customer ordering any equipment or beginning any detailed engineering work. <u>Small certified installations are not required to provide the detailed diagrams.</u>

d) The Company will review the final design documentation and provide comments back to the Customer.

e) If any changes are made, the Customer should provide the Company a set of revised one-lines, schematics, construction drawings, etc. The Customer shall supply proposed settings for the required interconnection relays, including support documentation (e.g. calculations, fault studies, TOC relay coordination curves, etc.) for larger systems. The Customer should provide the proposed On-Line Test procedure (see Section 7) in advance of the actual testing. A coordination meeting (or correspondence) should be held with the Company, the contractors, and the Customer to clarify any questions that may exist before On-Line Witness Testing begins.

f) For facilities greater than 10 kW that do *not* use certified interconnection equipment, the Company requests certified test reports for the interconnection facility protective relaying and any equipment directly connected to the Company's system (such as Customer's transformers and/or breakers). Company may witness the tests, calibrations, and relay setting applications. The Company shall be given at least 5 business day notice of any testing or calibration so arrangements can be made for witnessing, if witnessing is not waived. <u>Separate test reports are not required for small interconnection packages that have been certified to comply with IEEE 1547.1 or 1a by a nationally recognized testing laboratory (NRTL) under UL 1741.</u>

g) The final "as-built" documentation, including all drawings and final "as left" relay settings, must be provided by the Customer to the Company no later than 90 days after commercial operation.

5.0 SPECIFIC PROTECTIVE RELAYING REQUIREMENTS

5.1 GENERATION SIZE CLASSIFICATIONS

The Company has established eight different 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. The Colorado 3667 Rules directly address classes 1 - 4. Colorado 3900 Rules address class 5. These classes are:

1. 10 kW and under (small)
2. Over 10 kW to 100 kW (system dependent)
3. 100 kW to 1 MW (medium)
4. 1 MW to and including 10 MW (large)
5. Above 10 MW (usually transmission)
6. Hot Transfer Standby Generation
7. Demand Reduction Generation
8. Fast Transfer Systems

Where multiple generators are connected to the Company's system through a single service point*, the class will be determined by the sum of the generator ratings.* The classes are based upon generator 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 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 protective measures to be taken. See section 5.14 for spot and grid secondary network connected facilities.

The relays indicated in Figures 10.1 through 10.5 are for the *protection of the Company and the Company's other customers*. In each application, protective relaying associated with the interface requirements will be reviewed by the Company as described in the following sections*. Customers shall be responsible for determining their own relay settings.* A Customer should provide documentation that their interconnection relaying and settings are in accordance with these documents before the start of relay trip checks. <u>Small certified interconnection packages up to 30 kW (300W if certified to IEEE 1547.1a) normally do not require relay setting determination.</u>

For most non-certified 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:

a) Meets or exceeds ANSI/IEEE Standards for protective relays (i.e., C37.90, C37.90.1, and C37.90.2)
b) Extensive documentation covering application, testing, maintenance, and service.
c) Positive indication of what caused a trip (Targets).
d) A means of testing that does not require extensive unwiring (e.g. a draw out case, test blocks, FT-1 switches[17], 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 Colorado. For units less than 100 kW, certification by a testing professional, such as qualified by NETA (InterNational Electrical Testing Association) or equivalent, will be accepted. Other testing documentation may be accepted at the sole discretion of the Company Engineer.

[17] FT-1 is a Westinghouse testing switch that can be connected into panel board control wiring to enable insertion of test signals without disconnecting the wiring.

5.2 PROTECTIVE RELAYING DEFAULT SETTINGS

The relay settings given in IEEE 1547 are the default protective relay settings for Facilities interconnected with the Company.[18] Large facilities may require some modifications to these default values. The following are the IEEE 1547[19] default values. For equipment certified under IEEE 1547a, the default settings in 1547a should be used. The standard and its guides should be consulted for additional details.

[18] See Section 4.1 on required underfrequency trip settings.
[19] IEEE 1547 – 2003; IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

Table 1—Interconnection system response to abnormal voltages

Voltage range (% of base voltage a)	Clearing time(s) b [20]
V< 50	0.16
50 ≤ V< 88	2.00
110 < V < 120	1.00
V ≥120	0.16

a Base voltages are the nominal system voltages stated in ANSI C84.1-1995, Table 1. b DR ≤30 kW, maximum clearing times; DR > 30 kW, default clearing times.

Table 2—Interconnection system response to abnormal frequencies

DR size	Frequency range (Hz)	Clearing time(s)a
≤ 30 kW	> 60.5	0.16
	< 59.3	0.16
> 30 kW	> 60.5	0.16
	< {59.8 – 57.0} (adjustable set point)	Adjustable 0.16 to 300
	< 57.0	0.16

a DR ≤ 30 kW, maximum clearing times; DR > 30 kW, default clearing times.

Table 5—Synchronization parameter limits for synchronous interconnection to an EPS, or an energized local EPS to an energized Area EPS

Aggregate rating of DR units (kVA)	Frequency difference (Δf, Hz)	Voltage difference (ΔV, %)	Phase angle difference (ΔΦ, °)
0 – 500	0.3	10	20
> 500 – 1 500	0.2	5	15
> 1 500 – 10 000	0.1	3	10

4.2.6 Reconnection to Area EPS[21]

After an Area EPS disturbance, no DR reconnection shall take place until the Area EPS voltage is within Range B of ANSI C84.1-1995, Table 1, and frequency range of 59.3 Hz to 60.5 Hz.
The DR interconnection system shall include an adjustable delay (or a fixed delay of five minutes) that may delay reconnection for up to five minutes after the Area EPS steady-state voltage and frequency are restored to the ranges identified above.

[20] Clearing Times – This is the time interval from event initiation until the DG has been electrically isolated from the utility system. This includes detection time, delay timer, interposing relay time, and power flow interruption time. This is frequently *misinterpreted* as only being the delay timer setting.
[21] IEEE 1547 (2003); IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

5.3 INSTALLATIONS 10 KW AND UNDER

Except for certified interconnection packages, 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, and nameplate data of the generator(s), breaker(s), and disconnect switch(es)).[22] The Company will determine if a relay and 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. Most installations in this class feature a certified interconnection package. Each package will be reviewed to verify that it is certified and applied in a manner consistent with its certification. Relay settings will be reviewed for inverters certified under IEEE 1547a.

The protective relaying details are shown in Figure 10.1 A & B. If stand-alone energy storage (battery) is installed, see Figure 10.1 C and D. The installation must be permanently wired into a suitable load center in accordance with the NEC (see Article 690 for PV and 702 for Standby). A lockable disconnect switch must be provided, as shown in Section 4.2, that is readily accessible to the Company's personnel. 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 should be provided at the metering or PCC location indicating the location of the switch.

5.4 INSTALLATIONS FROM 10 KW TO 100 KW

Except for certified interconnection packages, 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 generator(s), breaker(s), disconnect switch(es), and certified test reports). The Company will determine if a relay and site inspection (i.e., witnessing the calibration and testing of the relays and operation of the generator and breakers, see Section 7) is required. *Installations using certified interconnection packages do not require the full documentation; however, review of relay settings for units over 30 kW (300 W if certified to IEEE 1547.1a) is required.*

Installations that use a certified package will be given a quick review. All installations that are not a standard package must be reviewed individually. These installations may vary somewhat from the layout shown in Figure 10.2 A & B. Some variation in the specifics of the requirements, but not the intent, will be allowed. The intent is to be consistent with IEEE 1547 requirements. The Company must approve all variations. Non-certified installations in this class may use either industrial grade relays or utility grade relays.

5.5 INSTALLATIONS FROM 100 KW TO 1 MW

All non-certified 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 generator(s) and breaker(s)/disconnect switch(es) and certified test reports will be provided to the Company by the Customer, see Section 4.4). 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. *The documentation and review can be reduced if certified interconnection packages are used.* For this size range, the proposed relay settings must be provided for certified packages.

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 IEEE certification process certifies the design and functionality for only one inverter package with its associated energy source.* It does not address the increased system and protection impacts that multiple certified 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 use of certified inverters will reduce the time and cost of reviews and later commissioning.

[22] All facilities that are not based on certified inverters must be reviewed under Level 3, Full Study.

The intent of the protective relaying requirements is given in Figure 10.3 A & B. With some of the larger installations, the Customer instead of the Company may own the transformer and associated equipment. Utility grade protective relays and utility grade equipment are required. The protective relaying aspects of certified interconnection packages are accepted as meeting the utility grade requirement for that portion of the facility.

5.6 INSTALLATIONS FROM 1 MW TO 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 generator(s) and breaker(s)/disconnect switch(es) and certified test reports will be provided to the Company by the Customer, see Section 4.4). 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 photovoltaic sites. *The certification process certifies the design and functionality for only one inverter package with its associated energy source.* It does not address the increased system and protection impacts that multiple certified packages will have. Because of this, a site with multiple packages must be reviewed and additional protective equipment and field-testing will likely be required. The use of certified inverters will reduce the time and cost of reviews and later commissioning.

Facilities in this size range are strongly encouraged to be located within 2 line miles of the substation. Expensive system modifications and restrictive operating requirements become increasingly likely as the distance from the sub increases. Many rural systems will not accept this class of generation or may require extensive rebuilding and reinforcement. The Customer may be required to interconnect with the transmission system.

The intent of the protective relaying requirements is given in Figure 10.4. With some installations, the transformer and associated equipment are owned by the Customer instead of the Company. Utility grade protective relays and utility grade equipment are required.

5.7 INSTALLATIONS 10 MW AND ABOVE

In general, the Company's distribution system is designed to handle loads and generation up to 10 MW for urban/suburban circuits. Installations in excess of 10 MW are usually served from the subtransmission (46 or 69 kV) or transmission (115 or 230 kV) system. Generation facilities in excess of 10 MW are covered by the CPUC 3900 Rules. Installations over 10 MW are more likely to be FERC jurisdictional, which must be reviewed under the FERC SGIP (2014).

5.8 TRANSFER TRIP CONSIDERATIONS

Transfer trip (TT) is a protection method whereby the conditions at one location causes a signal to be sent via a high speed communication channel to another location resulting in a breaker trip or some other form of separation from the electric system to occur. For DG, the originating event is usually the feeder breaker at the substation tripping with the high speed signal being sent to the DG to cause separation from the distribution feeder. The TT may originate on the transmission system for high penetration situations, especially if the substation is supplied where no transmission voltage circuit breakers are present. TT is mainly used when studies indicate local anti-islanding protection is marginal or inadequate to ensure a timely disconnection to adequately protect the other customers on the feeder. The DG may desire this protection to protect a large rotating generator from damage.

For smaller DG and lower penetrations, TT is rarely needed since large rotating generators are typically not included. Since the DG's receiver must be connected to the feeder's breaker and since feeders are field switched, especially during contingencies, TT requires that the communications path to the new source is established using pre-installed transmitters, adding cost and complexity to the installation. When large rotating generators are included, TT will be necessary for many of the situations. While uncommon, TT may be needed for large inverter based facilities even without any rotating machines present.

5.9 HOT TRANSFER STANDBY GENERATORS

A Hot Transfer Standby Generation system is defined as one in which a Customer's generation can be connected to the Company's system for more than 2 minutes but not on a continuous basis. 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, and for systems that operate in parallel for less than 2 minutes, see section 5.11. Since this type of installation often employs a sensitive direction power relay to aid in separation, some of the interconnection requirements may be relaxed, at the sole discretion of the Company Engineer.

5.10 DEMAND REDUCING GENERATORS

A Demand Reducing Unit (sometimes referred to as a "load displacement" or “self-generating” unit, where the local demand is reduced) is one where a Customer is paralleled with the Company but no power is intentionally exported 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 system. The size classification (see Sections 5.3 through 5.7) will be determined from the generator’s rating and if more than one generating unit is at the site, all of the generators’ ratings will be summed together 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.

5.11 CLOSED TRANSFER SYSTEMS

A closed transfer system is defined as one in which the paralleling of the Company’s system and the Customer’s generating equipment is less than 2 minutes. A closed or soft transfer is permitted for the purpose of avoiding excessive voltage and frequency deviations to the Customer’s load. Where the load is large, the transfers are to have a controlled ramp rate so as to avoid undue voltage disturbances to other customers. If the paralleling time has been exceeded, a breaker or switch must be automatically tripped to isolate the Company’s system from the Customer’s generators, see Figure 10.5.

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 less than two-minutes and that will equal or exceed 1 MW of aggregated generation requires review and a signed interconnection agreement; see Section 1.3 for additional information on when an interconnection agreement is needed. This size and type are likely to require voltage supervision of reclosing.

5.12 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, the Company will request the customer 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.

5.13 SYNCHRONIZING/SPEED MATCHING

Synchronous Generators

The Company will review the settings of the Customer's synchronizing relaying to verify the settings are within the guidelines of IEEE 1547 (2003), Table 5. This is to ensure settings suitable to prevent excessive voltage transients on the Company's system are used. The Company shall not take responsibility for the appropriateness of any given setting for protecting the Customer's equipment. It is highly recommended that the Customer consult with the manufacturer of their equipment for settings that are appropriate for the protection of the Customer's equipment. <u>Small interconnection facility packages that are certified for use with synchronous generators will include this functionality.</u>

Sync-check relays (Device 25 or 25X per Figures 10.1-10.4) should be included in addition to the synchronizing relays on large synchronous generators. The 25X function should be a separate device (i.e., not included in the synchronizer) for all units 1 MW and above. The 25X, 25 relay, and any other sync relaying, must not allow the Customer's facility to energize a de-energized Company line. This is for the safety of the Company's personnel and the public. The maximum phase angle error and voltage difference allowed by the 25X relay, and other sync relaying as well, should be consistent with the guidelines in IEEE 1547 (2003), Table 5.

Induction Generators

Speed matching may be by any means such that voltage regulation and voltage flicker are held within the tolerances described in Section 3.2 and 3.3. Double-fed induction generators may behave similar to synchronous generators and need synchronizing relays similar to those required for synchronous generators.

For medium size induction generators (typically above 100 kW), a mechanical speed matching relay (device 15) set to accept mechanical speed within $\pm$3% of 60 Hz must be used. A $\pm$1% speed match band will be required for large induction generators. The largest effect on the system of bringing an induction generator to synchronous speed is the voltage drop associated with the magnetizing inrush current upon connection to the system.

5.14 GOVERNOR DROOP

All medium to large units with active governors should be operated in automatic mode unless directed otherwise by the Company Engineer. To provide equitable and coordinated system response to load and generation imbalances, governor droop should be employed and governors should not be blocked or operated with excessive dead-bands. Cogeneration units associated with an industrial process may not be able to provide large signal response but are encouraged to have small signal response active. The default droop setting is 5%.

5.15 DC FUSING

Larger generation units must have some form of interconnection facility protection redundancy to insure that a single failure does not disable all interconnection protective relaying and separation functions. For larger facilities, the use of a single, fused DC relaying string is not allowed. Adequate protection for the loss of a DC fuse must be provided. Figure 10.6 shows an example of a DC fuse scheme utilizing a loss of potential relay to trip the breaker. A loss of potential scheme shall be used when a duplicate relay scheme or package is not used. Due to the severe consequences that may occur for a large generation unit if all protective relaying is lost due to a blown fuse, some form of redundancy is required.

5.16 CERTIFIED INVERTERS CONNECTED TO A SECONDARY VOLTAGE NETWORK

The CPUC 3667(c) rules address the fast track process for certified inverter based interconnections to distribution spot and area (aka grid) networks. That section provides the screening criteria for fast track approval of certified inverter facilities connected to area networks and spot networks. The Company does not have many area networks and these have low capacity. As such, the facilities that pass the screens for area network interconnection approval may result in unacceptable network performance. If this occurs, the customer will be responsible for corrective measures or will need to cease operation. The company will strive to inform the customer when this appears likely. In some cases, advanced inverter capabilities can be used to achieve acceptable performance.

Approval is not being given for interconnection to networks of rotating machine generation or any generation that can contribute substantial fault current. Network protectors include high speed, sensitive reverse power tripping. In general, the protective equipment and breakers associated with rotating machines cannot remove the generation before the network protectors have opened. Depending on the conditions, this may totally disconnect the customer or customers, which defeats the high reliability purpose of having network service. IEEE 1547.6 provides guidance for the interconnection of DGs with secondary voltage networks. Interconnection review will be in conformance with 1547.6.

For medium or larger facilities, interconnection of certified inverter facilities may not be feasible for spot networks. The company does not have area networks capable of accepting medium size interconnections. If the spot network serves a single customer and *that customer accepts the possible reduction in service reliability*, then additional consideration of interconnection will be given. A successful interconnection will be designed to operate such that at no time does the generation exceed the load. This requires that a margin be left such that the unexpected shut-down of any part of the load will not drop the load below the generation output. This may require dynamic control and minimum import control of the inverter output to shave output under certain conditions.

6.0 METERING REQUIREMENTS

6.1 GENERAL

Metering[23] installation requirements for the different categories of Customer-owned parallel generators are the same as those outlined in the current revision of the *Xcel Energy Standard for Electric Installation and Use* 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 application process. If this is not done or a change in tariff is requested in mid-review, a significant delay during review or commissioning may occur.

Typically, high-side metering will be used when a 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's side of ownership of the electric facilities.

Regardless of the size of the facility or options used, all metering installations must be reviewed and approved by the Electric Meter Engineering Department. At installations that require load profile metering, the Customer may be required to provide communications as determined by Electric Meter Engineering for remote interrogation of the metering.

6.2 METERING TARIFFS

Tariff Sheets P7-P10 provide the Schedule of Purchase Payments and the Purchase Payment Amount Table. The NM tariff addresses CPUC Rule 3664. The PV tariff addresses the RES rules that apply only to photovoltaic installations, including payments for renewable energy credits (RECs).

The Company tariffs govern the purchase of power from and sale of power to qualifying facilities. These tariffs govern both power purchases with buy-sell metering arrangements and with net metering arrangements. Net metering is available under several arrangements. The Customer should consult the

[23] References to “metering” in this manual refer to revenue metering for measuring power and energy to the customer or from the customer unless specifically noted otherwise, such as for “production metering” or telemetry.

Company tariffs, as approved by the CPUC, to determine the details, conditions, and rates available for their situation.

All facilities interconnected under the Net Metering Tariff NM are required to include a production meter to measure the total AC output of the eligible renewable source, with exception of on-site certified inverter based solar generation 10kW or less, unless otherwise installed under the provisions of PUC Rule 3664(e)(II). This provision allows for installing a production meter for solar generation 10kW or less, with Customer consent, at the Company expense or by Customer request at the Customer's expense. If the facility is under the Photovoltaic Tariff PV, this meter is also used to register PV energy generated for Renewable Energy Credits (RECs). If a facility is required to have telemetry to the Company, the production meter may also be used in some situations to provide this metering information, see Section 8.4 for additional information.

The Tariffs also specify the requirements, conditions, and cost methodology for the Company to provide maintenance power and standby rates to the Customer.

The Customer should consult the Company tariffs, as approved by the CPUC, to determine the details, conditions, and rates required for their situation. The Company is not required to purchase power from the Customer during system emergencies and certain operational circumstances. The tariffs and Rules detail these conditions.

The Rules specify the cost responsibilities for the additional costs incurred to meter the Customer's generation, provide net metering where applicable, provide production metering where applicable, and perform meter reading and processing. The Customer should consult the Company tariffs, as approved by the CPUC, to determine the details, conditions, and rates that apply to their situation.

6.3 METERING CONFIGURATIONS

10 kW and Less Net Metering

Most residential customers pay a bundled flat rate for their power at the time this document was issued. The rate is composed of the measured energy used and a fixed fee. Other rate classes have similar flat rates. Colorado rules allow net metering of the energy portion of the bill for qualifying facilities, see CPUC Rule 3664. In most cases, either the existing meter or a new meter placed in the same meter socket is used to perform the net metering. All customers served under net metering, photovoltaic, or some standby services are required to have a Production Meter, with exception of on-site certified inverter based solar generation 10kW or less, unless otherwise installed under the provisions of PUC Rule 3664(e)(II). This provision allows for Company installation of a production meter for solar generation 10kW or less, with Customer consent, at the Company's expense or by Customer request at the Customer's expense. This meter measures the AC output of the renewable generation.

Production Metering Restrictions on Connected Load

The tariff requirements for the production meter require that it measure the total AC energy produced by the renewable source. No customer load may be connected on the inverter side of the production meter. The exception is interconnecting under the requirements of Guidance No.3, discussed below. There must be no energy flow towards the inverter. The only exception applies to generation facility, long term, ongoing minor losses, and control power. Examples would include inverter standby power, transformer magnetizing power, grounding bank losses, facility monitoring power, etc. Any power provided, such as to a monitor, should be hard wired. If a receptacle is used, access to the receptacle must be restricted. Any other facility power or convenience outlets must be supplied from the main AC load center panel of the customer. Examples of other facility power would be lighting, occupied facility buildings, etc.

Other Metering Options

When the Customer does not qualify for net metering or has opted out of net metering, the Customer might provide some of their own power with their generation. In these cases, the existing metering is set to register only power delivered to the customer and will not record power exported to the Company. Standby or maintenance rates are available for larger customers.

“Separate load metering,” with generation metering separate from the load metering, is available. This arrangement is also called simultaneous buy-sell. This meter is installed before the generation is connected. A meter, with separate registers for in and out, is usually installed to separately account for generation (and for consumption when the unit is off-line). Power is delivered by the Company to the Customer through the load serving metering. Certain facilities may also qualify for REC payments. The Customer should consult the Company tariffs, as approved by the CPUC, to determine the details, conditions, rates, and REC payment programs available for their situation.

The net metered and buy-sell rates require the measurement of the AC total power production of the renewable source. Any design that blocks access to this AC measurement location will make the facility ineligible for the renewable tariffed rates, such as net metering.

Metering and Architecture Considerations When Electric Storage Is Present

Electric storage systems may be interconnected under specific conditions as discussed in detail in separate Guidance Documents. The three Guidance Documents are:

- Guidance No. 1 for the Interconnection of Electric Storage as Stand-Alone Sources, Parallel Operation for Customers without Generation, and in Parallel with Self-Generation
- Guidance No. 2 for Interconnection of Electric Energy Storage Systems Operated on the AC side of the Paired Onsite Renewable Generation Connected Under a Net Metering Tariff
- Guidance No. 3 for Interconnection of Electric Storage Systems Operated on the DC side of the Paired Onsite Renewable Generation Connected Under a Net Metering Tariff

Net Metering applies to Retail Renewable Generation operating in parallel with the utility with suitable metering to register net customer consumption. Electric storage systems are eligible for inclusion with renewable generation under net metering if the storage is only charged by the renewable generation. This combined renewable generation system may fully participate in net metering.

Electric storage systems that are charged by any other source may not participate in power export to the utility through the utility delivery meter.

Guidance No.1 is available for when storage will be used as a standby power source under NEC Article 702, Optional Standby Systems. Customers may have generation to provide part of their energy interconnected in parallel with the utility source provided the generation does not export power to the utility through the utility delivery meter. The customer may use electric storage with or without a customer generator.

Guidance No. 2 provides the requirements for operating electric storage in parallel with the utility when renewable generation is present that is eligible for net metering. The conditions for connecting and operating electric storage when connected on the AC side of the onsite renewable generation and behind the utility’s delivery meter.

Guidance No. 3 provides the requirements for operating electric storage that is charged by renewable energy, in parallel with the utility, when connect on the DC side of the onsite renewable generation and when net metering is used. When a production meter is utilized for REC payments, interconnection under Guidance No. 3 will result is a decrease in total REC payments, if REC payments are available.[24] Approval for interconnection under Guidance No. 3 is contingent on the applicant accepting this reduction in REC payments.

The three Guidance Documents, including illustrative typical one-line diagrams must be consulted for the details. Only the configurations under the conditions discussed are allowed for electric storage systems.

[24] Electric storage is a net consumer of energy. Losses are present when charging, discharging, and charge maintenance. These losses will decrease the recorded RECs.

7.0 DEMONSTRATION OF PROTECTIVE DEVICES

Customers are to demonstrate the correct operation and functionality of the interface protective devices. Only a simple, operation demonstration may be needed for small, certified interconnection packages. Some additional demonstration for larger or multiple certified packages may be required.

For larger facilities, especially where non-certified interface equipment is used, Customers must provide qualified electricians, technicians, and operators, as needed, to perform the demonstrations. The Customer must supply all personal protective equipment (PPE) required and designate any procedures necessary to ensure that appropriate safety precautions are taken while working near energized equipment. For large, complex facilities, the Company Engineer may require a written commissioning plan prior to the testing date.

The scheduling of this demonstration should be coordinated to comply with the time frames specified in the CPUC 3667 Rules. A 5 business day notice is required for larger facilities. The Company may need to schedule multiple parties to participate in the witnessing. Especially for facilities over 1 MW, Company linemen, relay testers, metering engineers, etc. may be needed to cover all of the aspects. Where the facilities are large compared to the feeder capacity, special arrangements such as temporary field switching may be needed. Coordination with feeder maintenance and construction may be required, which may delay commissioning completion. Based on the amount of generation and the type of generation at the site, the Company may require only a design and relay setting review and not a site visit. This is to be determined by the Company Engineer.

The commissioning testing and demonstration shall be conducted in accordance with the requirements of IEEE 1547.1, as specified in the CPUC 3667 Rules. IEEE 1547.2 provides additional information to consider for commissioning testing. A separate DG Commissioning document is available upon request to provide guidance for creating a detailed test plan for large, non-certified facilities.

8.0 GENERAL OPERATING REQUIREMENTS

8.1 DE-ENERGIZED CIRCUITS

Customers 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 generating facility.* In addition, Customer will be held responsible for all damages and injuries resulting from such actions. The Company may require the Facility to discontinue operation during an emergency in accordance with the CPUC 3667 rules. Large facilities may be required to curtail or cease operation for contingency situations such as storms or equipment failure. The feeders may need to be switched into a configuration where full output cannot be tolerated. In many cases, mitigations can be put into place if the Customer requests contingency configurations to be studied and mitigation made, at the Customer's expense.

8.2 OPERATIONAL LOG

Customers should maintain an operating log at each generating facility rated 100 kWac and over indicating changes in operating status (available or unavailable), maintenance outages, trip indications, or unusual conditions found upon inspection. Also refer to CPUC Rule 3926.

8.3 FACILITY GENERAL REQUIREMENTS

For the size units as specified, the following shall be provided:

a) For greater than 100 kWac, voice communication to the facility via public telephone or mutually agreed circuits.

b) For all, name and telephone number of the designated operating agent. For less than 100 kW, this may be the owner/operator.

c) For greater than 500 kWac, Customer's designated operating agent and other operating personnel are required to be familiar with the Company's line clearance/operating procedures.

8.4 TELEMETRY

Monitoring and Control

As distributed generation penetration rises, there will be an increasing need to provide the Distribution System Operations with ongoing indication of the distributed production. There will be evolving requirements as the penetration rises in both facility size and functionality required. Work is in progress for smart inverters and advanced interconnection and communication standards to facilitate this evolution. At high penetrations of DG, there will be a growing need to also provide control instructions to the inverters such as shifting to a different voltage control mode. The following is an overview of the requirements at the time this manual is published. The customer should verify the requirements as part of the application process.

Cyber Security

Cyber security is a growing concern in all aspects of industry. The cyber security requirements will be evolving and changes in security for monitoring and control are expected. The nature of the information and the communications method will drive the type and level of security employed. Large DGs will require greater cyber security due to their greater impacts on the system and the more extensive control requirements that they will require. The addition of a communications security device will become a normal requirement when public communications channels and internet communications are used.

1 MW and Greater

a) Customer facilities 1 MWac and greater 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, and interface security device when needed, and ongoing secure communication channel costs to the designated Company point of receipt. This does not apply to facilities that qualify for closed or soft load transition status.
b) The information required may vary by location and unit size but all will include near real time active and reactive power, point of delivery voltage, connection status, and integrated energy. Near real time means samples every 5 seconds or less with less than one second delivery delay. Whenever the Customer is located in a transmission constrained region, generates power far in excess of the distribution load, or is in an area with a high penetration of generation, *more stringent monitoring and control may be needed.* If the Customer is located on a high penetration distribution circuit, especially if it is capacity constrained, is likely to be required to have more extensive control.
c) Additional information may be required, either initially or later, such as ambient, wind speed, or solar intensity.
d) The Company may require the ability to remotely disconnect or curtail the generation for larger installations 1 MW and larger. For some installations, a remote ability to change control modes, such as power factor setting, may be required. This will be determined during the facility review. This control is needed to quickly address distribution and transmission constraints and contingency conditions, as required by NERC reliability standards, which must be addressed quickly. If the Customer does not provide a suitable device to be controlled, the Company will install a suitable device on the feeder, at Customer expense, to provide the control. The control of this device will be exercised in a non-discriminatory manner in compliance with the NERC standards, CPUC Rules, tariffs on file, and the provisions, if any, stated in the operating

attachment to the Interconnection Agreement. Interface with the inverters or the site controller is preferred as it provides more, and often less disruptive options.

e) The Company either will provide the specifications for the equipment or the needed equipment, at cost, to the Customer for the Customer's site. The Company will provide the equipment at the Company's designated delivery location at Company cost.
f) The Customer is expected to provide suitable floor space or enclosure in a suitable, location.
g) *The Customer is to provide the secure communications channel* to the Company's dispatch facility or other designated location to provide the required communication path between the DG facility and the Company. The Company will define the needed minimum security, through-put, and latency requirements needed. This will be determined in the facility review.
h) Maintenance costs for telemetry related equipment at the Customer's site is the responsibility of the Customer.

250 kW to 1 MW

a) As DG penetration levels increase, the Company will require the ability to remotely monitor the output of intermediate size installations as distribution control, safety, and power quality will require greater DG monitoring in addition to Company provided feeder monitoring. This information is needed to quickly address transmission and distribution constraints and contingency conditions, as required by NERC reliability standards and CPUC, which must be addressed quickly. This may not apply to facilities that qualify for closed load transition status.
b) The information required will vary by location and unit size but all will include real and reactive power, voltage, energy production, and unit connection status at or faster than the designated scan intervals. Whenever the Customer is located in a transmission or distribution constrained region, generates power in excess of the distribution load, or is in an area with a high penetration of generation, this monitoring will be needed.
c) The Customer is expected to provide suitable space or enclosure for the installation of the monitoring and telemetry equipment. The cost of Customer's site terminal equipment, any added metering, interface security device when needed, and ongoing communication channel costs to the designated Company point of receipt is the Customer's responsibility when telemetry is a condition of interconnection.

10 kW to 250 kW

a) The Company may require the ability to remotely monitor the output of medium to small size installations. This information is needed to quickly address transmission and distribution constraints and contingency conditions, as required by NERC reliability standards and CPUC, which must be addressed quickly. This does not apply to facilities that qualify for closed load transition status.
b) Monitoring of small DG may be done through an aggregator or Company provided neighborhood collector.
c) The information required will vary by location and unit size but all will include real and reactive power, voltage, and unit connection status. Whenever the Customer is located in a transmission or distribution constrained region, generates power in excess of the distribution load, or is in an area with a high penetration of generation, this monitoring is more likely to be needed.
d) The Customer is expected to provide suitable space or enclosure for the installation of the monitoring and telemetry equipment. The cost of Customer's site terminal equipment, any added metering, interface security device when needed, and ongoing communication channel costs to the designated Company point of receipt is the Customer's responsibility when telemetry is a condition of interconnection.

9.0 MAINTENANCE AND FUTURE CHANGES

9.1 MAINTENANCE

Customers shall maintain their equipment in good order. The Company reserves the right to inspect Customer's facilities whenever it appears that a Customer is operating in a manner hazardous to the Company's system integrity and/or customer safety. *The Customer shall maintain the facility equipment* *in accordance with the manufacturer's recommendations.* The Customer should keep records of the maintenance performed to document their compliance with this rule. Also refer to CPUC Rule 3667(j)(III) and 3926. Any specific maintenance requirements will be documented in the Interconnection Agreement, Exhibit D.

For larger installations, the Customer is encouraged to perform functional testing of all breakers, relays, and transformers yearly. Installations should have a full relay calibration check performed according to the manufacturer's recommended schedule by qualified personnel. Certified inverters and microprocessor relays are self-checking and a longer testing cycle is appropriate. The Company reserves the right to inspect the maintenance records and interconnection equipment of the Customer's facility if misoperation or other indication of incorrect interconnection performance or failure.

9.2 DESIGN CHANGES AFTER COMMERCIAL OPERATION

Any modifications to the interconnection facility after the date of commercial operation that alters the unit size, configuration, or other substantial aspects will need to be reviewed by the Company. Suitable commissioning testing may be required. Replacement of certified interconnection packages of like rating generally does not constitute a modification assuming packages are of the same capacity and use the same settings.

Any "Field Modification" or "As Built" AC/DC protection and synchronizing schematics associated with any interconnection device will need to be forwarded to the designated Company representative.

10.0 TYPICAL RELAYING ONE-LINE DIAGRAMS

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

10.1 0-10 KW

10.1A Typical parallel generation interconnections with certified interconnection packages.

10.1B Typical parallel generation interconnections not using certified interconnection packages.

10.2 10-100 KW

10.2A Typical parallel generation interconnections not using certified interconnection packages.

10.2B Typical parallel generation interconnections with certified interconnection packages.

10.3 100 KW – 1 MW

10.3A Typical parallel generation interconnections not using certified interconnection packages.

10.3B Typical parallel generation interconnections with certified interconnection packages.

10.4 1 – 10 MW

Typical parallel generation interconnections not using certified interconnection packages.

10.5 SOFT LOADING TRANSFER

Typical interconnection for short term paralleling to allow a closed transition transfer of load.

10.6 SEPARATE FUSING EXAMPLE

Illustration for providing relaying redundancy when using a single DC supply.

11.0 DEFINITIONS

The definitions in the “IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems”, IEEE 1547, apply to this document as well. The following definitions are in addition to the ones defined in IEEE 1547, or are repeated from the IEEE 1547 standard. Some definitions have been taken from the CPUC 3667(a) Definitions. If a conflict arises in these definitions, the meaning shall be consistent with CPUC 3667(a) in reference to interconnection process matters and IEEE 1547 in reference to interconnection technical requirements.

Area EPS – The area electric power system that is also referred to as the Company’s electric “distribution system” in this document.

Business Day - Monday through Friday, excluding Federal holidays.

Certified Equipment Package - Interconnection equipment that has been tested and listed by a nationally recognized testing and certification laboratory (NRTL) for continuous interactive operation with a utility grid and meets the definition for certification under Order 2006, issued by the Federal Energy Regulatory Commission on May 12, 2005, in Docket No. RM02-12-000. The extent of the equipment package is defined by the type test performed to certify the package under IEEE 1547.1. Most equipment is tested under the protocol and requirements of UL 1741. “Type-Certified” is the same as “pre-certified” and “certified” when used in this text.

Company – Public Service Company of Colorado d/b/a Xcel Energy - the 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 Operation – A generation facility is defined as operating in continuous parallel with the Company’s electric distribution system whenever the parallel condition exceeds 2 minutes. *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 Generation (DG) - A small generation facility interconnected to the Area EPS for the purpose to offset consumption or export power. DG is sometimes referred to as Distributed Energy Resource (DER) to recognize the energy resource may include storage.

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. The voltage level at which distribution systems operate differ among areas.

Distribution Mitigations - 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 effect the interconnection customer's operation of on-site generation. Distribution upgrades do not include interconnection facilities.

Facility Study - The facilities study that specifies and estimates the cost of the equipment, engineering, procurement, and construction work (including overheads) needed to implement the conclusions of the System Impact Study.

Feasibility Study - The study that identifies any potential adverse System impacts that would result from the interconnection of the Generating Facility, especially those impacts that may result in a condition that is unsafe, unreliable, or impractical.

Generation - 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 Distributed Generation(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”

Grid Network – Secondary or Area Network system with geographically separated network units where the network-side terminals of the network protectors are interconnected by low-voltage cables that span the distance between sites. The low-voltage cable circuits of Grid Networks are typically highly meshed and supplied by numerous network units. Grid Network is also commonly referred to as “Area Network” or “Street Network”.

Highly Seasonal Circuit - A circuit with a ratio of annual peak load to off-season peak load greater than six (6).

Impact Study - A System Impact study that identifies and details the electric System impacts that would result if the proposed Generating Facility were interconnected without project modifications or electric System modifications, focusing on the adverse System impacts identified in the Feasibility Study, or to study potential impacts, including but not limited to those identified in the scoping meeting. A System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the electric System.

Interconnection Application – The written request by an Interconnection Customer to interconnect a new Generating Facility to increase the capacity of, or make a material modification to the operating characteristics of an existing Generating Facility that is interconnected with the Company's distribution system. The application request is submitted using the interconnection application form provided by the Company

Interconnection Costs - The reasonable costs of connection, switching, metering, transmission, distribution, safety provisions, and administration incurred by the Company which are directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a Generating Facility to the extent such costs are in excess of the corresponding costs which the Company would have incurred if it had not engaged in interconnected operations but instead generated an equivalent amount of power itself or purchased an equivalent amount of power from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs pursuant to CPUC 3667.

Interconnection Customer – Any entity, including utility, any affiliates or subsidiaries of either, that proposes to interconnect its small generating facility with the Company's distribution system. Interconnection Customer is also referred to as "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 Generating Facility to the Company's System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades.

Line Section - That portion of a Company's 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 single premises or group of premises. This is also referred to as the "Customer" or "Generation Facility".

Minimum Daytime Loading - The lowest daytime peak of the year on the Line Section.

Network System - A collection of Spot Networks, Grid Networks, or combinations of such networks on a Primary Network Feeder or Primary Network Feeders that supply them. This may also consist of primary feeders networked ("tied together") to supply connected loads.

Network Transformer - A transformer designed for use in a vault to feed a variable capacity system of interconnected secondaries.

Open Transfer - A method of transferring the local loads from the Company to the generator or back such that the generator and the Company are never electrically connected in parallel together.

Party - The Company and the Interconnection Customer separately or in combination.

Point of Common Coupling - The point where the Local EPS is connected to the Company's system.

Power Conversion Unit (PCU) - An inverter or AC generator, not including the energy source.

Primary Network Feeder - A feeder that supplies energy to a Network System or the combination of a Network System and other radial loads. Dedicated Primary Network Feeders are feeders that supply only Network Transformers for the Grid Network, the Spot Network, or both. Non-dedicated Primary Network Feeders, sometimes called combination feeders, are feeders that supply both Network Transformers and non-network load.

Quick Closed - A method of generation transfer that parallels for less than 500 msec with the Company and has suitable timers and interlocks that limit the parallel duration to less than 500 msec with the Company.

Qualifying Facility - A cogeneration facility or a small power production facility that meets the FERC criteria for qualification contained in 18 C.F.R. Section 292.203. Renewable sources and fossil sources that meet specific efficiency plus multi-use of the source energy content.

Quick Open - A method of generation transfer that does not parallel with the Company and has a brief open interval, typically about 100 msec.

Rated Capacity - The total AC nameplate rating of the Power Conversion Unit(s) at the Point of Common Coupling.

Renewable Energy Standard (RES) – CPUC Rules 3650-3667.

Secondary Network - The low-voltage circuits supplied by the network units (the Network Transformer and its associated network protector.

Secondary Network System - An AC power Distribution System in which Customers are served from three-phase, four-wire low-voltage circuits supplied by two or more Network Transformers whose low-voltage terminals are connected to the low-voltage circuits through network protectors. The Secondary Network system has two or more high-voltage primary feeders, with each primary feeder typically supplying multiple Network Transformers, depending on network size and design. The Secondary Network system includes automatic protective devices intended to isolate faulted primary feeders, Network Transformers, or low-voltage cable sections while maintaining service to the customers served from the low-voltage circuits.

Shared Secondary - Any connection on the secondary side of a distribution transformer that serves more than one customer.

Short Circuit Current Contribution Ratio - The ratio of the Generating Facility's short circuit contribution to the short circuit contribution provided through the Utility's Distribution System for a three-phase fault at the high voltage side of the distribution transformer connecting the Generating Facility to the Company's System.

SGIA and SGIP – Small Generator Interconnection Agreements and Small Generator Interconnection Procedures as presented in FERC Order 2006 unless specially identified as the 2014 version.

Small Utility - A Utility that serves less than 50,000 customers.

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

Spot Network - A Secondary Network system consisting of two or more network units at a single site. The low-voltage network side terminals of these network units are connected together with bus or cable. The resulting interconnection structure is commonly referred to as the "paralleling bus" or "collector bus." In Spot Networks, the paralleling bus does not have low-voltage ties to adjacent or nearby Secondary Network systems. Such Spot Networks are sometimes called "Isolated Spot Networks" to emphasize that there are no low-voltage connections to network units at other sites.

Study Process - The procedure for evaluating an Interconnection Application that includes the Full Interconnection Study scoping meeting, Feasibility Study, System Impact Study, and Facilities Study.

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

System Emergency - A condition on a Company's System that is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

Transmission System - Those facilities as defined by using the definitions established by FERC.

Upgrade - The required additions and modifications to the Company's System at or beyond the Point of Common Coupling. Upgrades do not include Interconnection Facilities.

Utility - A utility or public utility as defined in serving electric customers subject to the jurisdiction of the Commission.

12.0 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 32 (1972), "IEEE Standard Requirements, Terminology, and Test Procedure for Neutral Grounding Devices"

IEEE Std 100 (2007), "IEEE Standard Dictionary of Electrical and Electronic Terms"

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

IEEE Standard 142 (2007), "IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems – Green Book"

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

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

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

IEEE Std 1547 (2003), "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems"

IEEE Std 1547a (2014), "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1"

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

IEEE Std 1547.1a (2015), "IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems – Amendment 1"

IEEE Std 1547.2 (2008), "Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems"

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

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

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

IEEE Std 1547.7 (2013), "IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection"

IEEE Std P1547.8, "Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementing Strategies for Expanded Use of IEEE Standard 1547"

IEEE C37.90 (2005), "IEEE Standard for Relay Systems Associated with Electric Power Apparatus"

IEEE Std C37.90.1 (2012), "IEEE Standard Surge Withstand Capability (SEC) Tests for Protective Relays and Relay Systems".

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

IEEE C37.95 (2002), "IEEE Guide for Protective Relaying of Utility-Consumer Interconnections"

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 (2005), "IEEE Recommended Practice on Surge Testing for Equipment Connected to Low Voltage (1000V and less) AC Power Circuits"

IEEE Std C62.92.2 (1989), "IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Part II – Grounding of Synchronous Generator Systems"

ANSI C84.1 (2011), "Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)"

UL Std. 1741 (2010), "Inverters, Converters, and Controllers for use in Independent Power Systems"

NESC – "National Electrical Safety Code", ANSI C2 (2017), Published by the Institute of Electrical and Electronics Engineers, Inc.

NEC – "National Electrical Code", NFPA 70 (2017), Published by the National Fire Protection Association

13.0 PUBLIC UTILITY COMMISSION RULES AND XCEL ENERGY TARIFFS

13.1 LINK TO COLORADO PUC RULES

https://www.colorado.gov/pacific/dora/pucrules

4 CCR 723-3

13.2 SPECIFIC CPUC RULES OF INTEREST

3650-3667 – Renewable Energy Standard rules

3652 – RES Definitions

3658 – Standard Rebate Offer

3664 – Net Metering Rules

3667 – 0-10 MW DG interconnection Rules

3900-3975 – >10 MW DG Rules

13.3 LINK TO XCEL ENERGY TARIFF SHEETS

http://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/CO-Rates-&-Regulations-Entire-Electric-Book.pdf

13.4 SPECIFIC TARIFF SHEETS OF INTEREST

Sheet 47 – Secondary Standby Service

Sheet 55 – Primary Standby Service

Sheet 91 - Schedule WES; Wind Energy Service

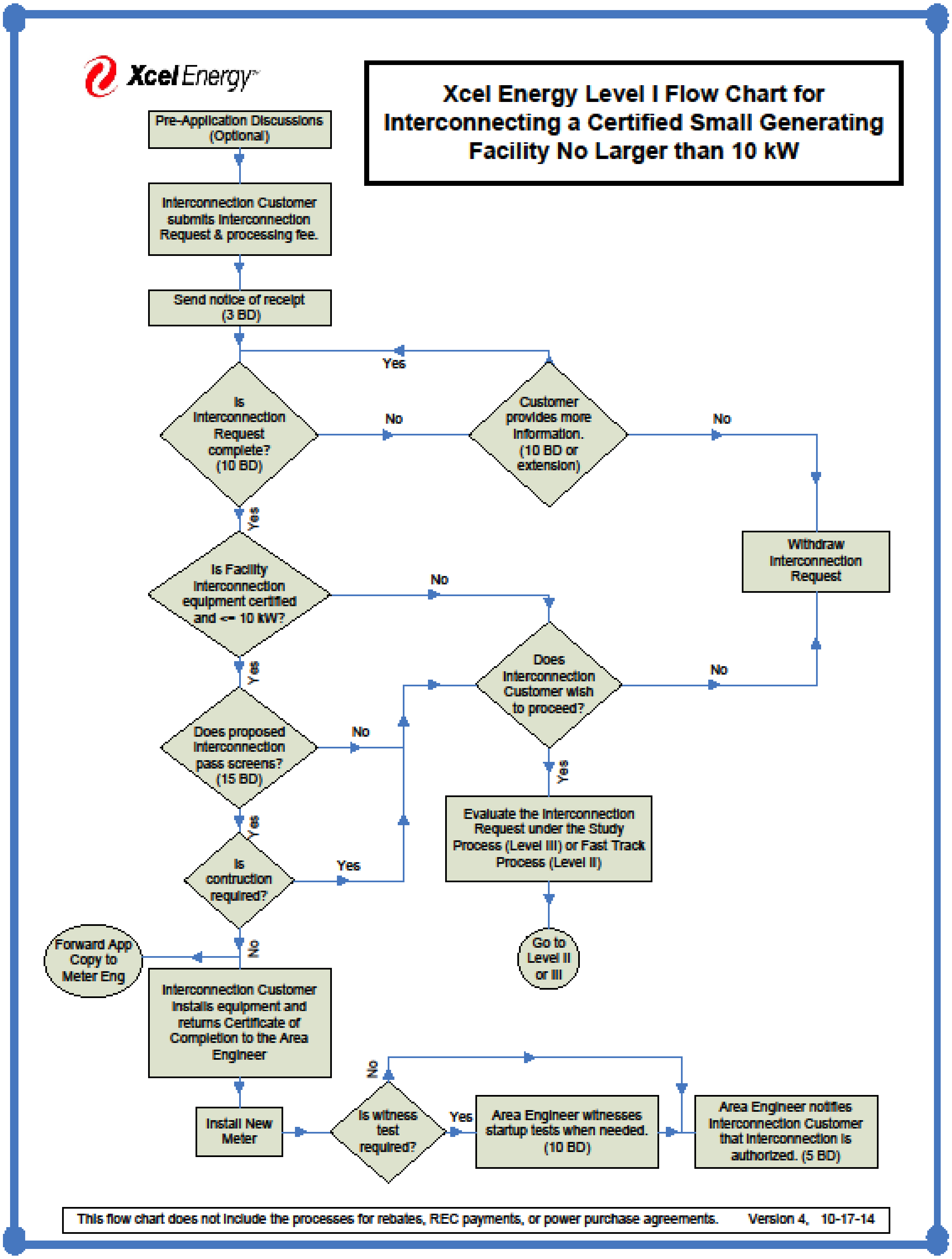
Sheet 92 – Schedule NM; Net Metering Service

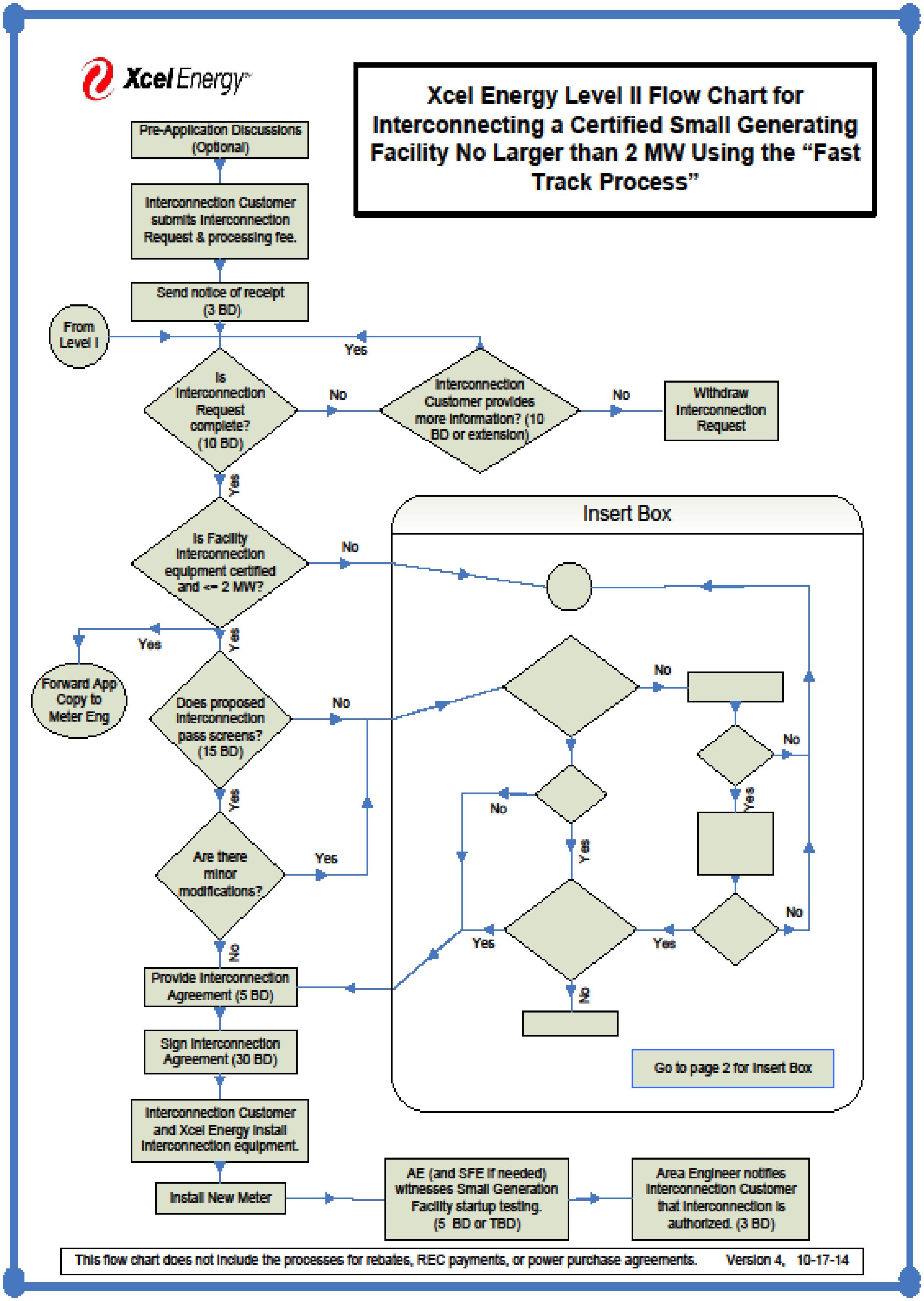
Sheet 93 – Schedule PV; Photovoltaic Service

Sheet P2 – Small Power Production and Cogeneration Policy

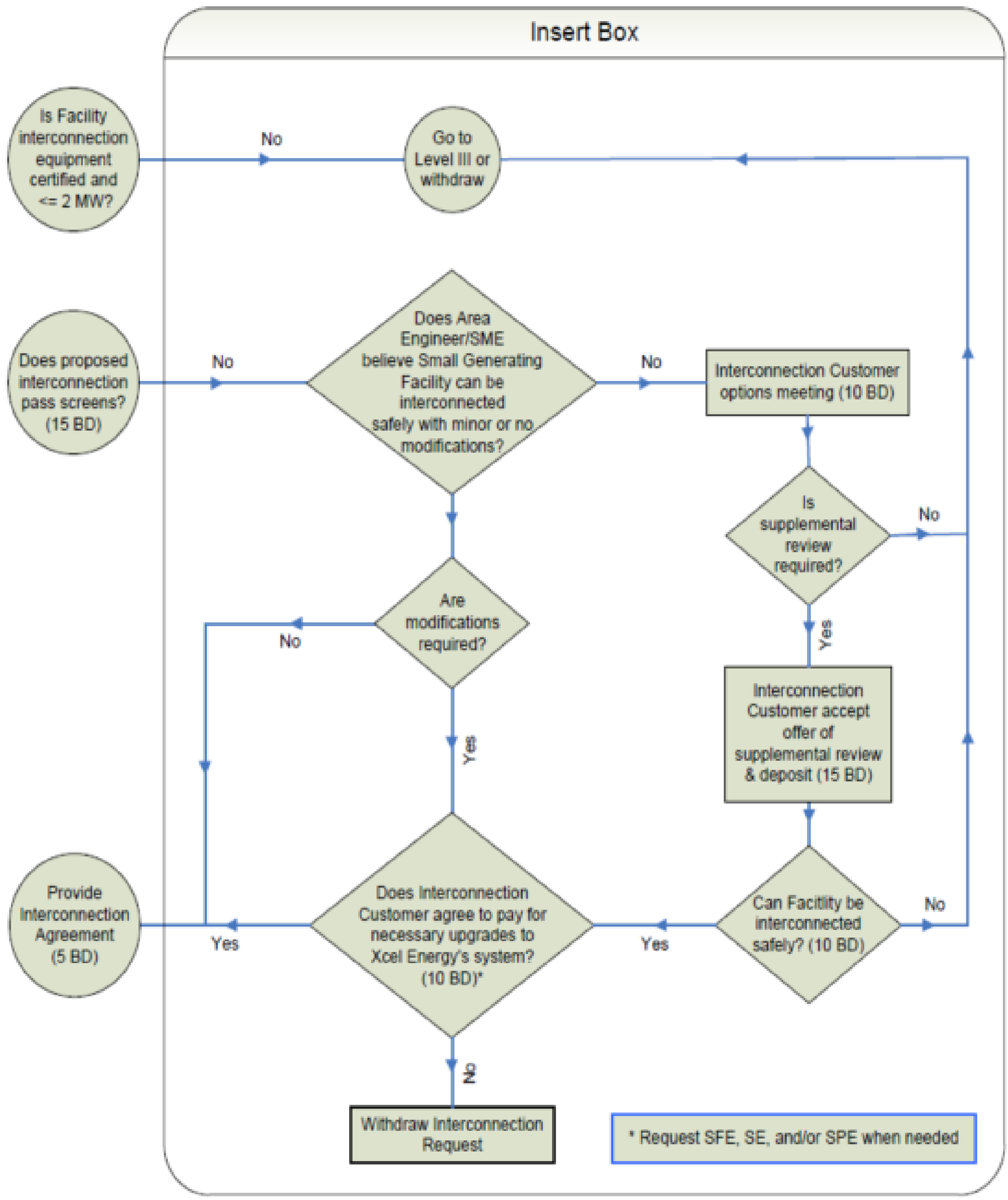
Sheet P10 – Purchase Payment Amount Table

14.0 PROCESS FLOW CHARTS

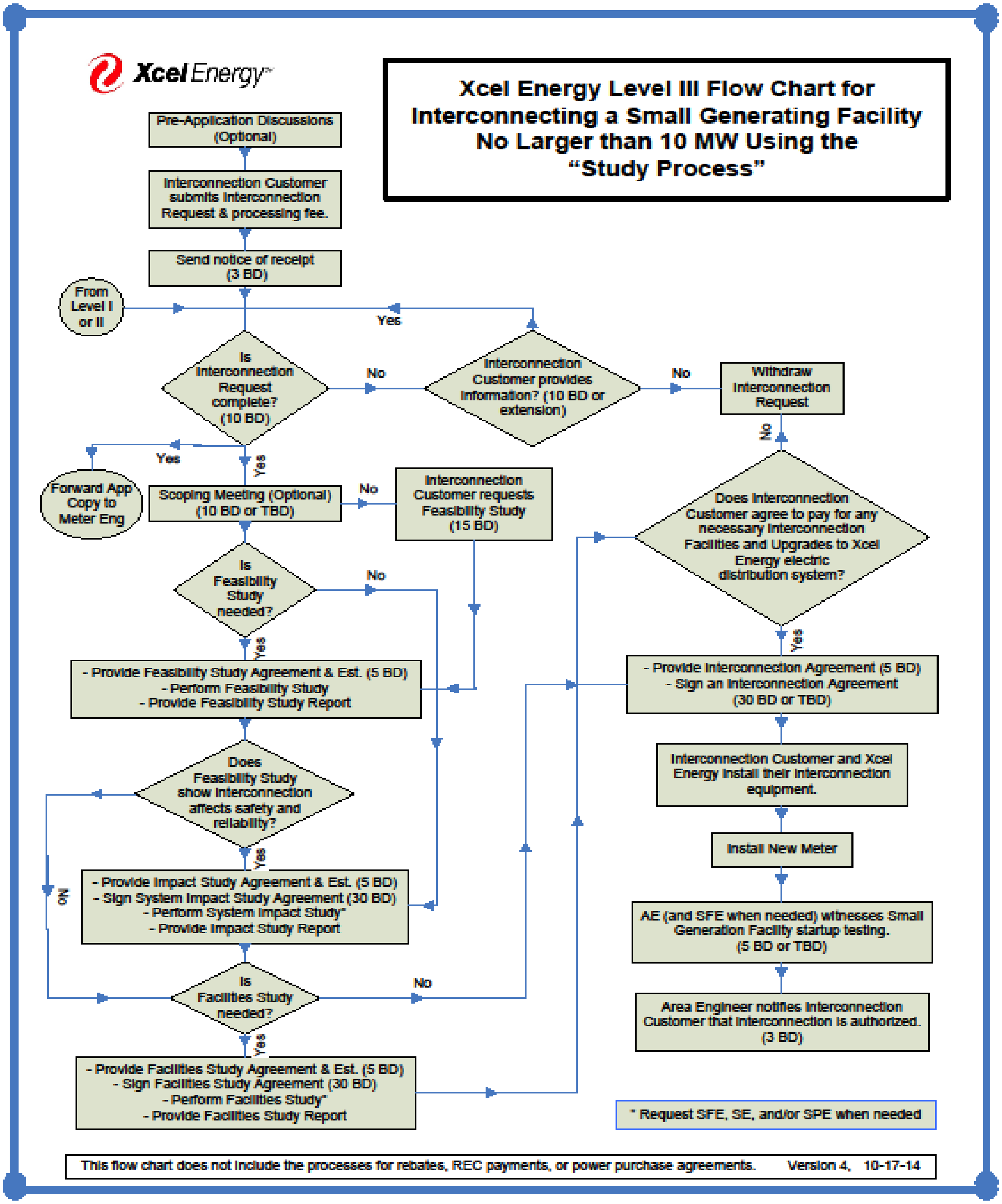



Xcel Energy
Xcel Energy Level II Flow Chart for Interconnecting a Certified Small Generating Facility No Larger than 2 MW Using the "Fast Track Process"
Pre-Application Discussions (Optional)
Interconnection Customer submits Interconnection Request & processing fee.
Send notice of receipt (3 BD)
From Level I
Is Interconnection Request complete? (10 BD)
Yes
No
Interconnection Customer provides more information? (10 BD or extension)
No
Withdraw Interconnection Request
Yes
Is Facility interconnection equipment certified and <= 2 MW?
No
Insert Box
Yes
Yes
Forward App Copy to Meter Eng
Does proposed interconnection pass screens? (15 BD)
No
Yes
Are there minor modifications?
Yes
No
Provide Interconnection Agreement (5 BD)
Sign Interconnection Agreement (30 BD)
Interconnection Customer and Xcel Energy install interconnection equipment.
Install New Meter
AE (and SFE if needed) witnesses Small Generation Facility startup testing. (5 BD or TBD)
Area Engineer notifies Interconnection Customer that interconnection is authorized. (3 BD)
No
No
No
No
Yes
Yes
Yes
Yes
No
Go to page 2 for Insert Box
This flow chart does not include the processes for rebates, REC payments, or power purchase agreements.
Version 4, 10-17-14

Xcel Energy Level II Flow Chart for Interconnecting a Certified Small Generating Facility No Larger than 2 MW Using the "Fast Track Process"



This flow chart does not include the processes for rebates, REC payments, or power purchase agreements. Version 4, 10-17-14


Xcel Energy
Xcel Energy Level III Flow Chart for Interconnecting a Small Generating Facility No Larger than 10 MW Using the "Study Process"
Pre-Application Discussions (Optional)
Interconnection Customer submits Interconnection Request & processing fee.
Send notice of receipt (3 BD)
From Level I or II
Yes
Is Interconnection Request complete? (10 BD)
No
Interconnection Customer provides information? (10 BD or extension)
No
Withdraw Interconnection Request
No
Yes
Yes
Forward App Copy to Meter Eng
Scoping Meeting (Optional) (10 BD or TBD)
No
Interconnection Customer requests Feasibility Study (15 BD)
Does Interconnection Customer agree to pay for any necessary Interconnection Facilities and Upgrades to Xcel Energy electric distribution system?
Is Feasibility Study needed?
No
Yes
Yes
- Provide Feasibility Study Agreement & Est. (5 BD)
- Perform Feasibility Study
- Provide Feasibility Study Report
- Provide Interconnection Agreement (5 BD)
- Sign an Interconnection Agreement (30 BD or TBD)
Does Feasibility Study show Interconnection affects safety and reliability?
Interconnection Customer and Xcel Energy install their interconnection equipment.
Install New Meter
Yes
No
- Provide Impact Study Agreement & Est. (5 BD)
- Sign System Impact Study Agreement (30 BD)
- Perform System Impact Study*
- Provide Impact Study Report
AE (and SFE when needed) witnesses Small Generation Facility startup testing. (5 BD or TBD)
Is Facilities Study needed?
No
Yes
Area Engineer notifies Interconnection Customer that interconnection is authorized. (3 BD)
- Provide Facilities Study Agreement & Est. (5 BD)
- Sign Facilities Study Agreement (30 BD)
- Perform Facilities Study*
- Provide Facilities Study Report
* Request SFE, SE, and/or SPE when needed
This flow chart does not include the processes for rebates, REC payments, or power purchase agreements. Version 4, 10-17-14

15.0 FEE SCHEDULE AND DOCUMENT CHECK LIST

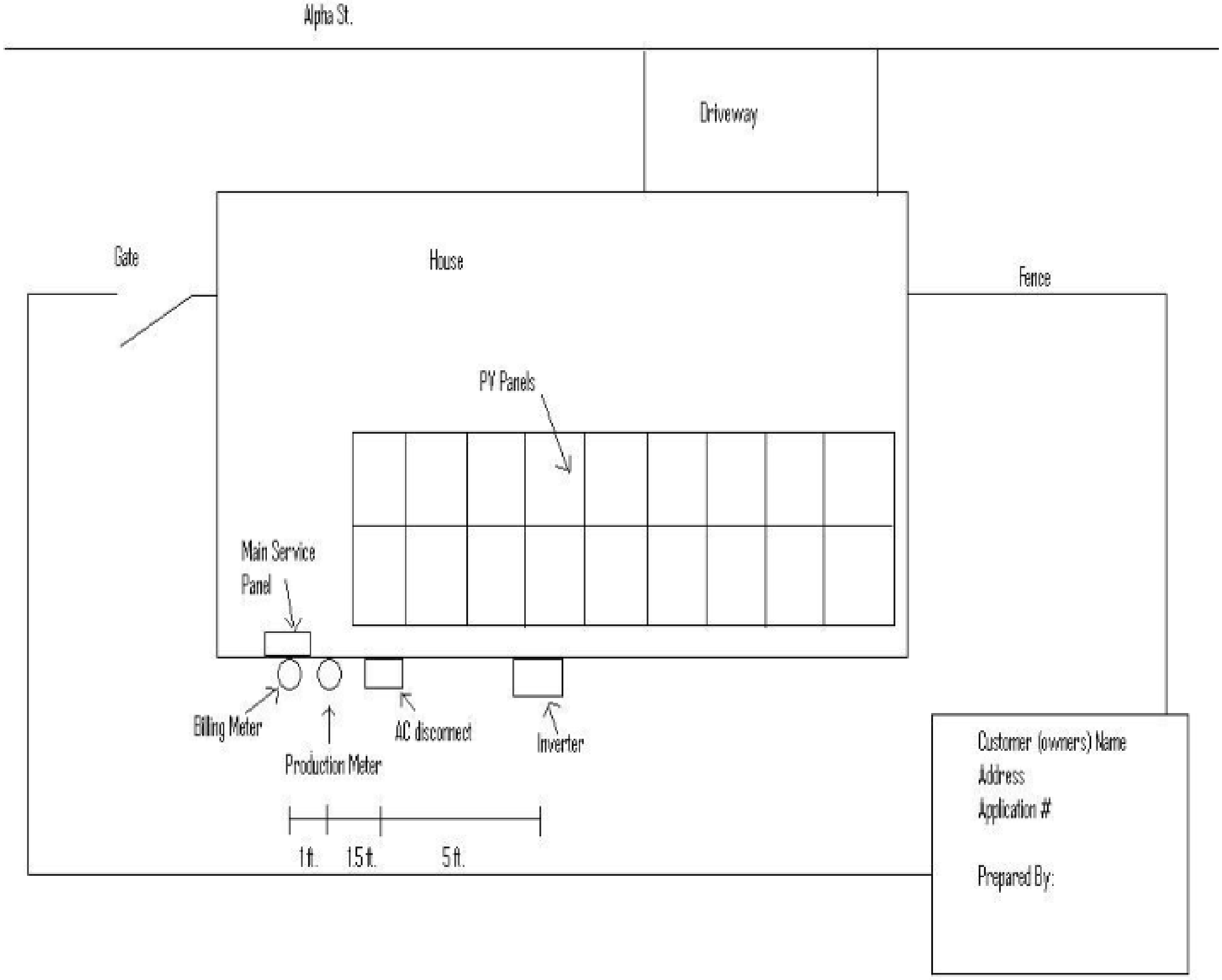
Costs and Documents Required for DG Interconnection by Size and Interconnection Equipment Type

10/9/2009 Total Facility Size	Interconnect Equipment Type	Rule 3667 Review Level	Standard App Fee	Add'l Costs Note 3	System Costs Note 5	Startup Testing Witness	0 kW - 10 kW App Form	0 kW - 10 kW I. A.	Certificate Completion Required	0 kW - 10 MW App Form	0 kW - 10 MW I. A.
≤10 kW	Pre Certified	I	$100	No	No	No	X	X	X		
	Non Pre Certified	III	$500	No	Maybe	Maybe			X	X	X
>10 kW-250 kW	Pre Certified	II	$1,000	Maybe	Maybe	Likely				X	X
	Non Pre Certified	III	$1,500	Maybe	Maybe	Likely				X	X
>250 kW-2 MW	Pre Certified	II	$2,000	Maybe	Likely	Likely				X	X
	Non Pre Certified	III	$3,500	Yes	Likely	Likely				X	X
>2 MW-10 MW	Pre Certified	III	$1,000	Yes	Yes	Yes				X	X
	Non Pre Certified	III	$1,500	Yes	Yes	Yes				X	X
>10 MW	Pre Certified	Note 1	Note 2	Note 2	Yes	Yes				Note 4	Note 4
	Non Pre Certified	Note 1	$1,500	Yes	Yes	Yes				Note 4	Note 4

Note 1	CPUC Rule 3667 applies up to 10 MW. Rule 3900 applies above 10 MW.
Note 2	Pre-Certification standards have not been established for > 10 MW interconnection equipment.
Note 3	≤ 10 kW is flat rate charge.
	Level II is a flat rate charge but some modification costs may be included as allowed in the Rules.
	Level III is Application Fee plus actual costs for each Study level performed plus Commissioning Testing.
Note 4	0 - 10 MW Application Form and Interconnection Agreement used as base documents.
Note 5	Payment for Company system modifications to accommodate interconnection

Size	Type	App Fee	Add'l Cost	Testing	Sys Mod	App Form	I.A.
0-100 kW Sec	HS Transfer	$0	No	Unlikely	No		
>100 kW Sec		$1/kW	Maybe	Maybe	Unlikely	X	X
Primary		$2/kW	Likely	Likely	Maybe	X	X
0-100 kW	Closed Transition	$0	Unlikely	Unlikely	Unlikely		
100 kW - 1 MW		$3/kW	Likely	Likely	Maybe	X	X
>1 MW		$5/kW	Yes	Yes	Likely	X	X

16.0 TYPICAL SMALL DG SITE-PLAN



Legible hand drawn site-plans are acceptable

17.0 REQUIRED DISCONNECT LABEL

The DG disconnect switch shall be labeled with a placard with bright yellow background, made from plastic laminate, mounted with permanent adhesive or rivets on the disconnect switch cover or immediately adjacent to the disconnect in a location clearly visible. The placard shall match the size and lettering illustrated as close as practical.

PHOTOVOLTAIC SYSTEM DISCONNECT

2” x 4¾”, 36 point Arial Bold

or

WIND SYSTEM DISCONNECT

or

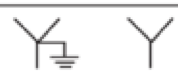
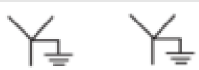
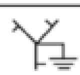
GENERATION SYSTEM DISCONNECT

18.0 GROUND REFERENCING TRANSFORMER CONFIGURATIONS

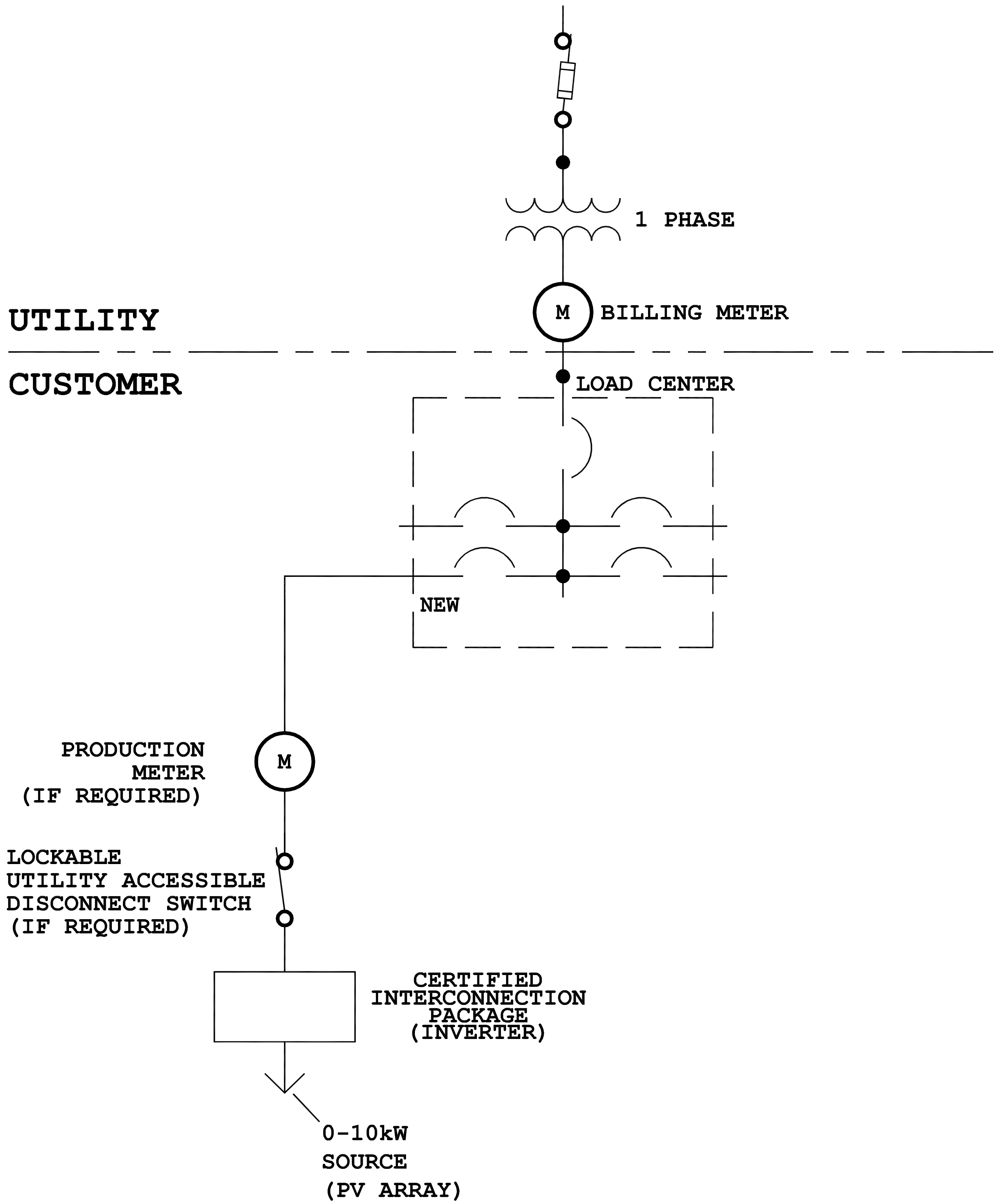
Three-phase distributed generation must be ground referenced when interconnected to the Company's 4-wire electric system. There are only two types of sources, from a transformer with the suitable configuration or a grounded wye rotating machine. Inverters do not provide a ground source but they may have interface transformers that can provide this source.

The power transformer configurations that can provide a zero sequence source are identified below. There is one specialty transformer that is a grounding source, called a zig-zag winding. It has no secondary bushings. The Company's standard line-transformer is the ground wye-wye ground. It will pass zero sequence ground reference current through to the opposite side but will not provide a zero sequence source.

If the Customer is supplying the step-up transformer, there must be either a secondary ground source with a suitable transformer winding configuration or a primary ground source provided. Reference Figure 10.4 for a sample one-line configuration with a primary side ground source.

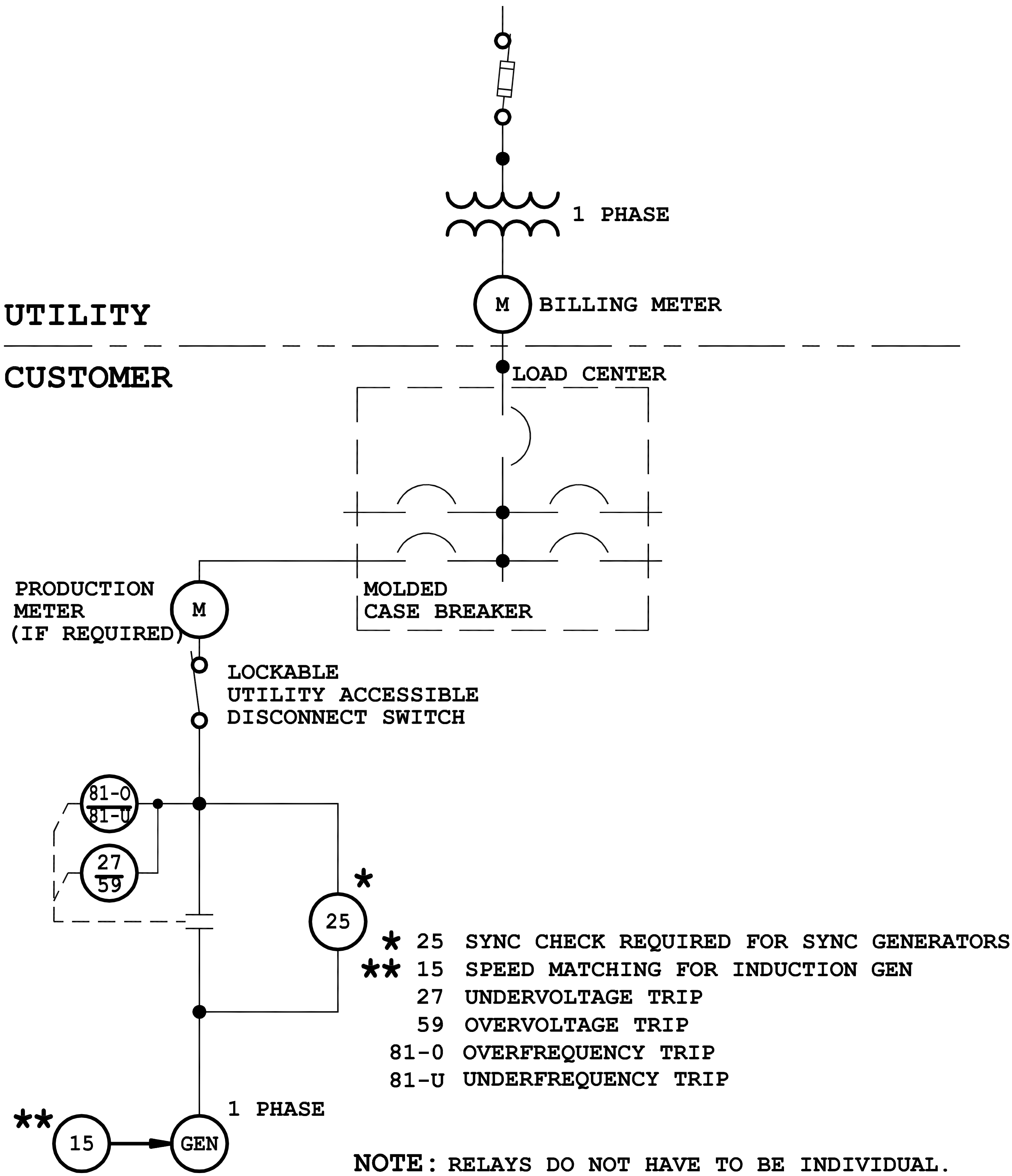
Transformation Primary (Pri.) ← → Secondary (Sec.)	Passes Zero Seq. Current?	Provides a Source for Zero Seq. Current?
	No	No
	No	No
	No	No
	Yes	No
	No	No
	No	Yes (to Sec. only)
	No	Yes (to Pri. only)
	No	No
	No	Yes (to Sec. only)
	Yes	Yes (to Pri. and Sec.)
	Yes	No
	Yes	Yes (to Pri. and Sec.)

19.0 TYPICAL ONE-LINE DIAGRAMS



3/15/2010

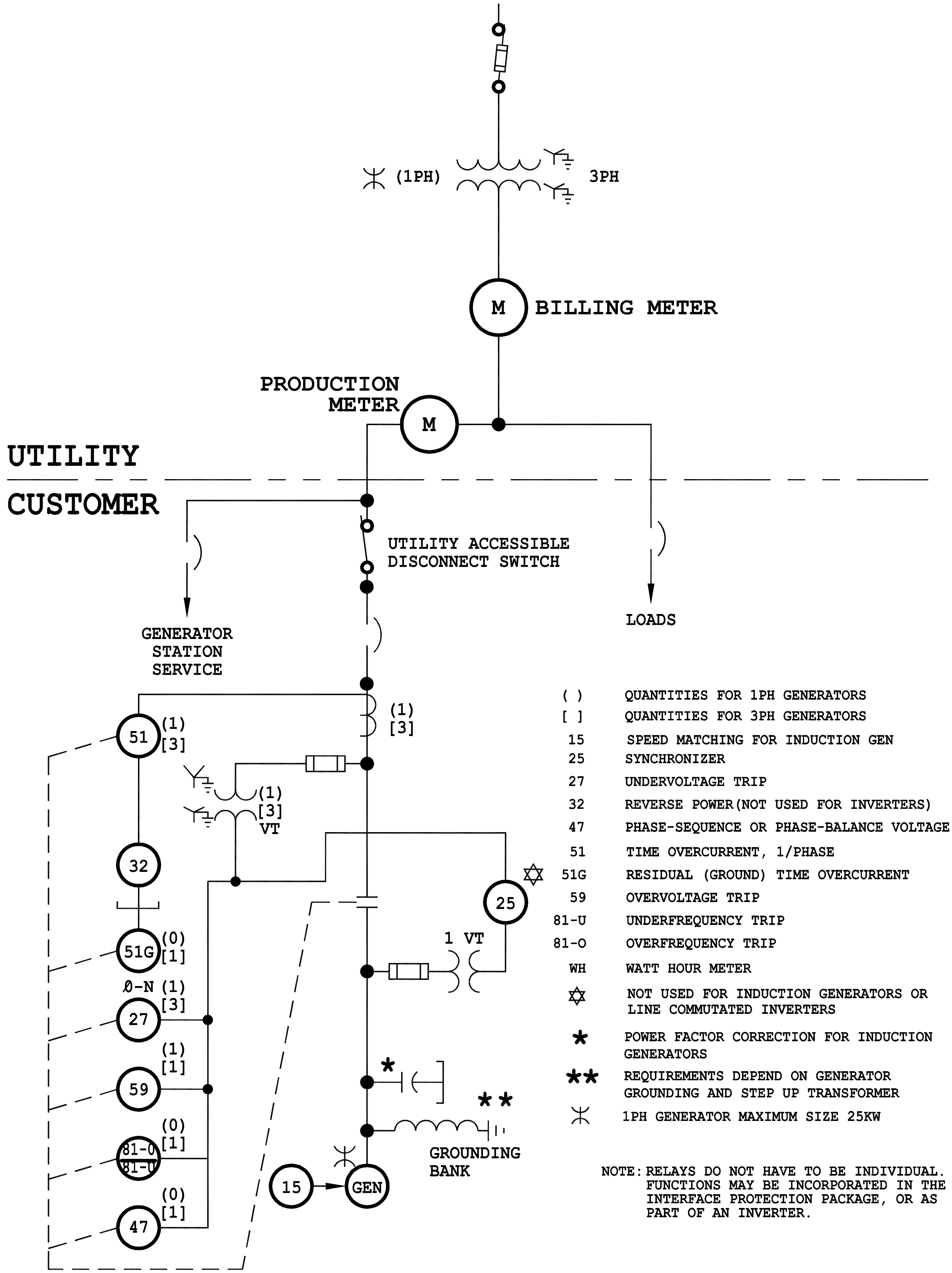
Xcel Energy	TYPICAL PARALLEL GENERATION CERTIFIED INSTALLATIONS LESS THAN 10kW, URBAN CONDITIONS	FIGURE NO. 10.1A



NOTE: RELAYS DO NOT HAVE TO BE INDIVIDUAL. FUNCTIONS MAY BE INCORPORATED IN THE INTERFACE PROTECTION PACKAGE, OR AS PART OF AN INVERTER.

3/15/2010

Xcel Energy	TYPICAL PARALLEL GENERATION NON-CERTIFIED INSTALLATIONS LESS THAN 10kW, URBAN CONDITIONS	FIGURE NO. 10.1B



3/15/2010

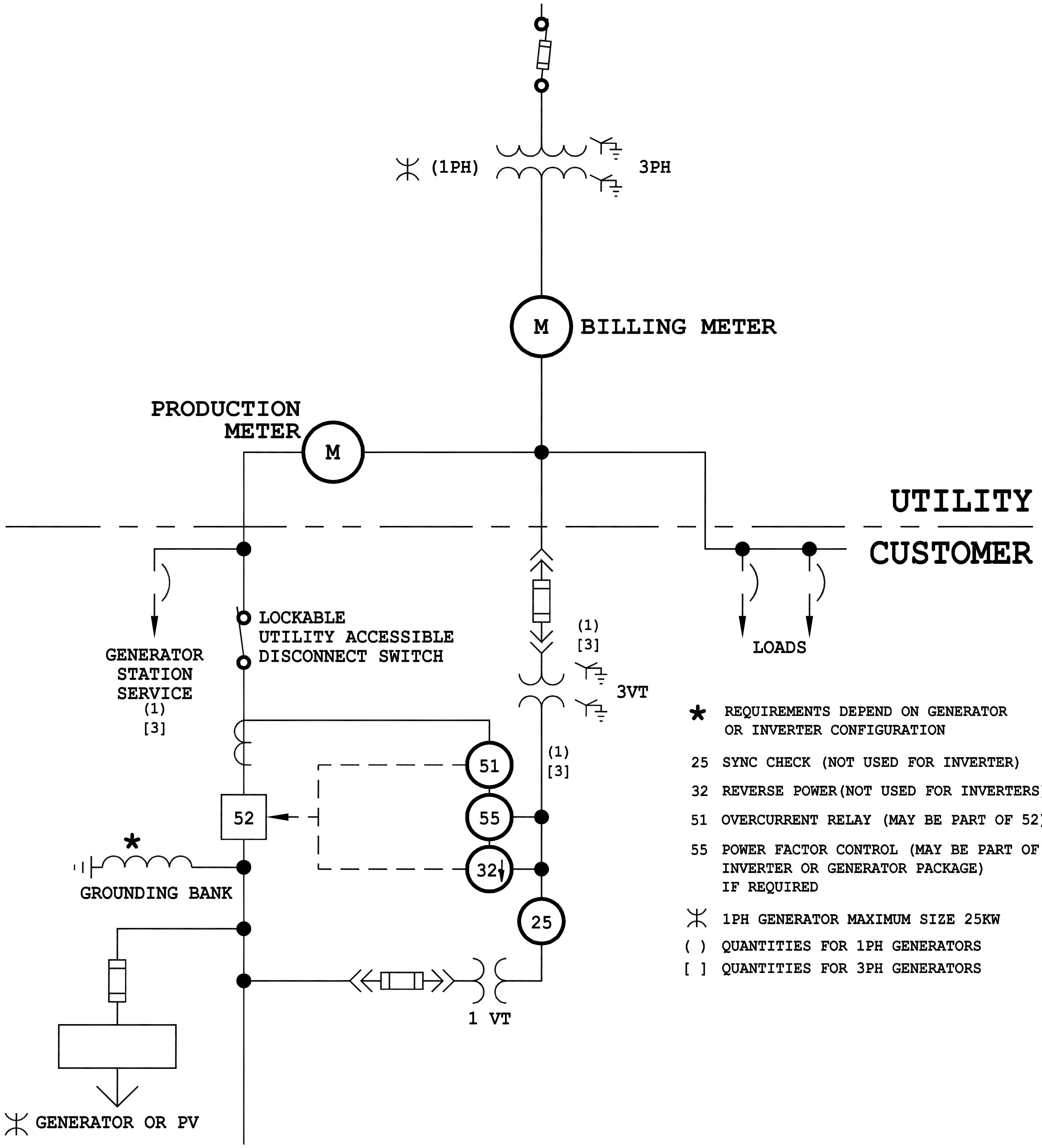
UTILITY GRADE OR HIGH QUALITY INDUSTRIAL GRADE RELAYS

Xcel Energy

TYPICAL PARALLEL GENERATION
INSTALLATIONS 10kW TO LESS THAN 100kW
URBAN CONDITIONS

FIGURE NO.

10.2A



* REQUIREMENTS DEPEND ON GENERATOR OR INVERTER CONFIGURATION

25 SYNC CHECK (NOT USED FOR INVERTER)

32 REVERSE POWER(NOT USED FOR INVERTERS)

51 OVERCURRENT RELAY (MAY BE PART OF 52)

55 POWER FACTOR CONTROL (MAY BE PART OF INVERTER OR GENERATOR PACKAGE) IF REQUIRED

1PH GENERATOR MAXIMUM SIZE 25KW

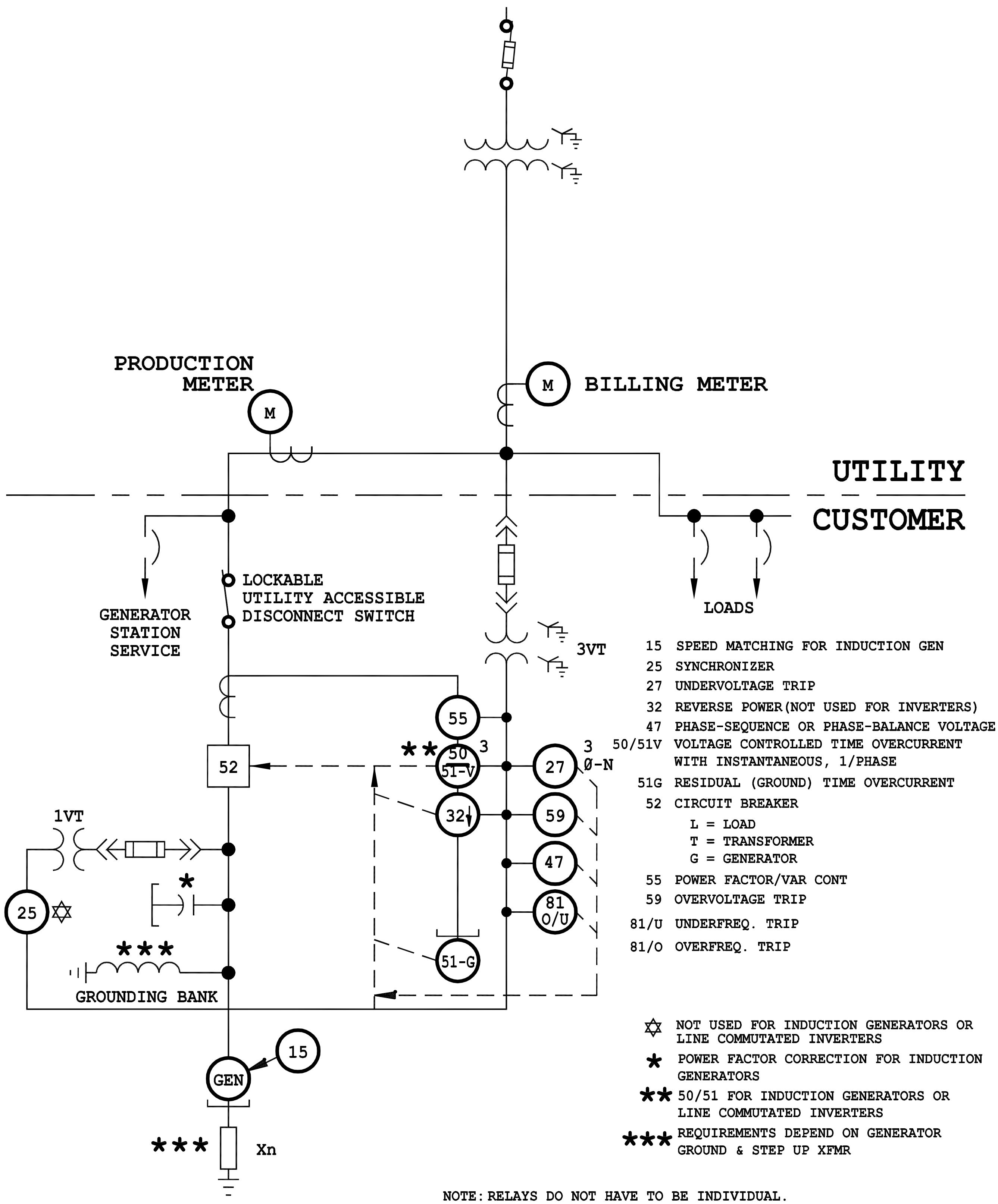
( ) QUANTITIES FOR 1PH GENERATORS

[ ] QUANTITIES FOR 3PH GENERATORS

NOTE: RELAYS DO NOT HAVE TO BE INDIVIDUAL. FUNCTIONS MAY BE INCORPORATED IN THE INTERFACE PROTECTION PACKAGE, OR AS PART OF AN INVERTER.

3/15/2010

Xcel Energy	TYPICAL PARALLEL CERTIFIED INSTALLATIONS 10KW TO LESS THAN 100KW URBAN CONDITIONS	FIGURE NO. 10.2B

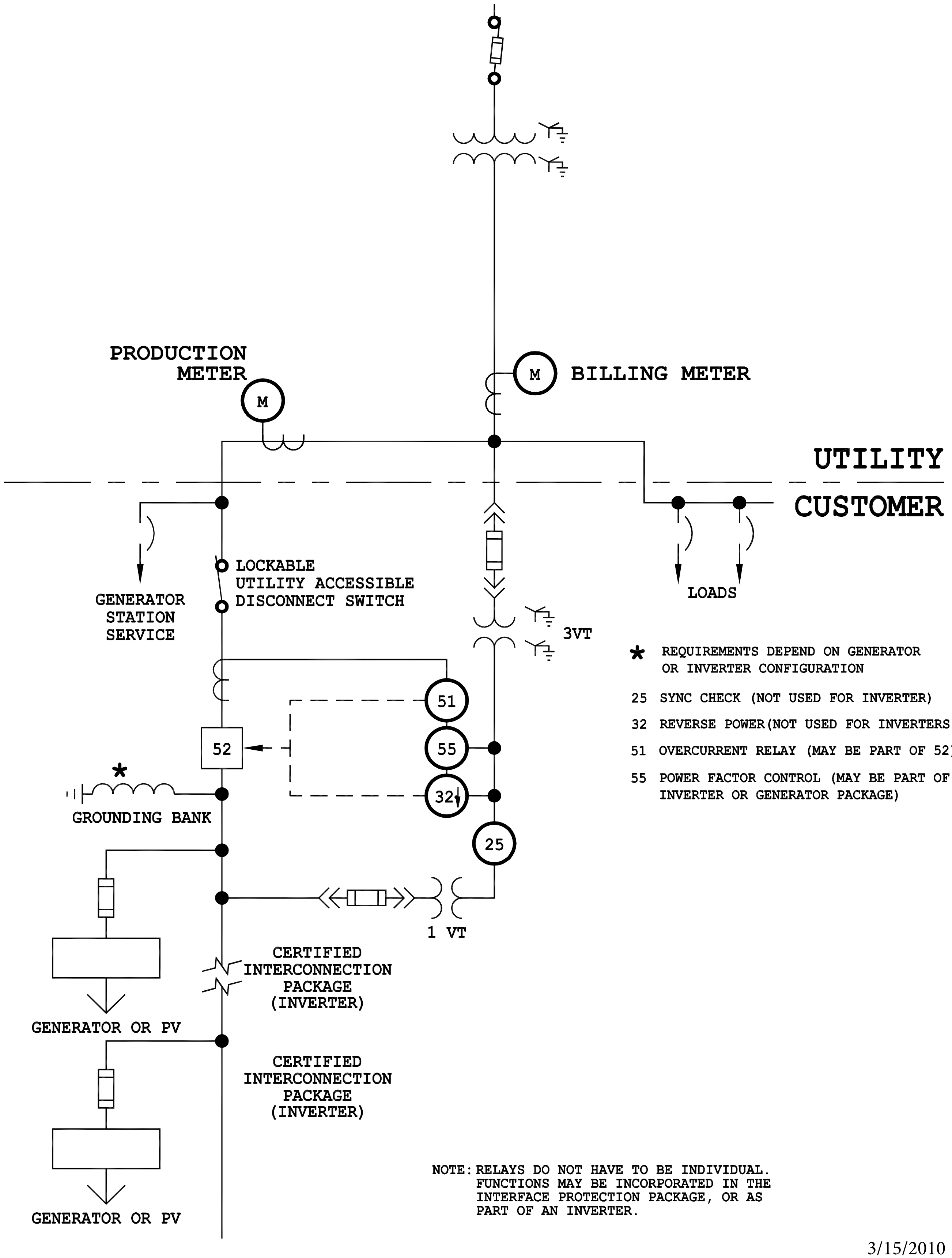


NOTE: RELAYS DO NOT HAVE TO BE INDIVIDUAL. FUNCTIONS MAY BE INCORPORATED IN THE INTERFACE PROTECTION PACKAGE, OR AS PART OF AN INVERTER.

UTILITY GRADE RELAYS

3/15/2010

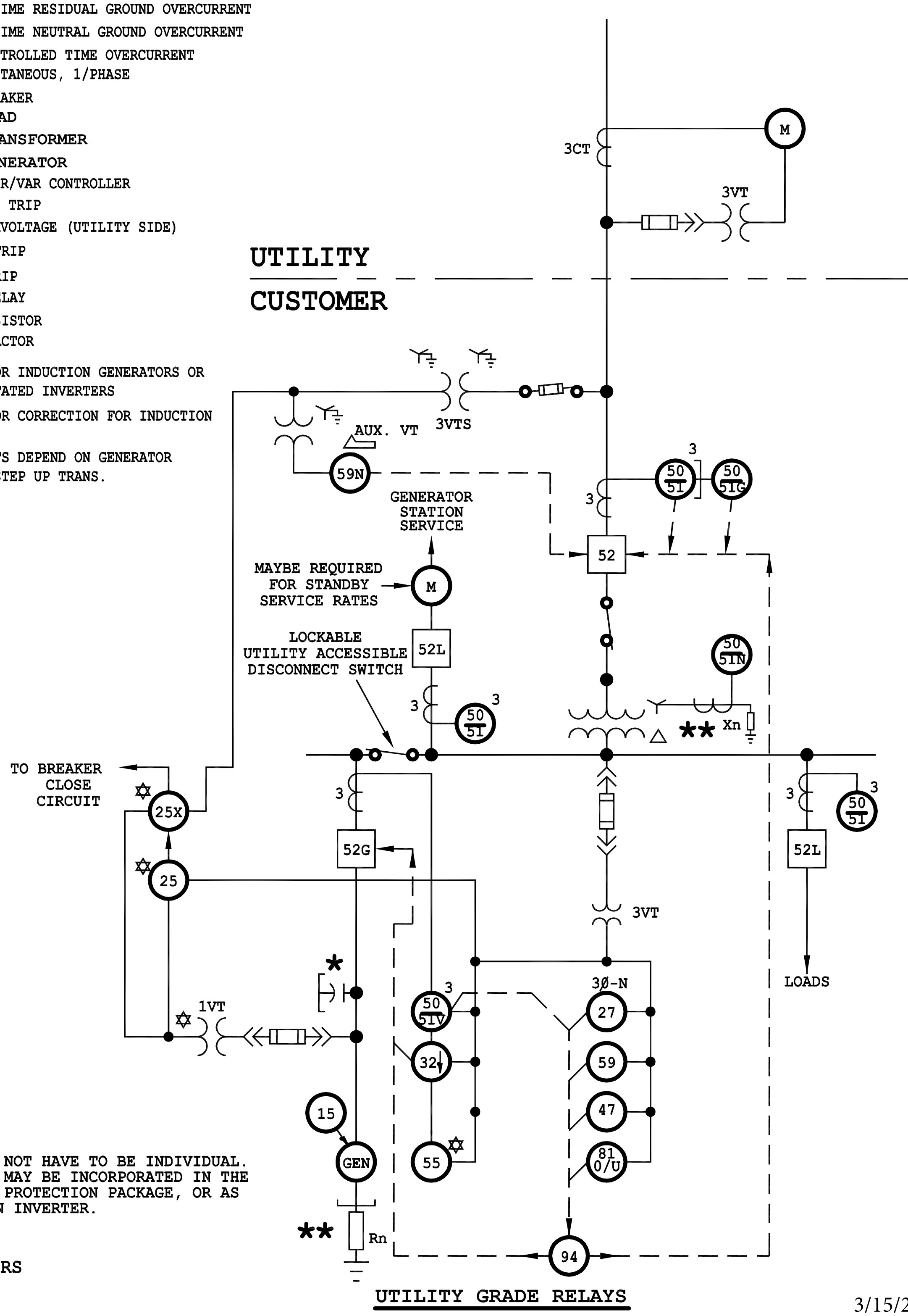
Xcel Energy	TYPICAL PARALLEL GENERATION INSTALLATIONS 100KW TO LESS THAN 1MW URBAN CONDITIONS	FIGURE NO. 10.3A



3/15/2010

Xcel Energy	TYPICAL PARALLEL CERTIFIED INSTALLATIONS 100KW TO LESS THAN 1MW URBAN CONDITIONS	FIGURE NO. 10.3B

15 SPEED MATCHING FOR INDUCTION GEN
25 SYNCHRONIZER
25X SYNC CHECK
27 UNDERVOLTAGE TRIP
32 REVERSE POWER(NOT USED FOR INVERTERS)
47 PHASE-SEQUENCE OR PHASE-BALANCE VOLTAGE
50/51 INST. AND TIME OVERCURRENT, 1/PHASE
50/51G INST. AND TIME RESIDUAL GROUND OVERCURRENT
50/51N INST. AND TIME NEUTRAL GROUND OVERCURRENT
50/51V VOLTAGE CONTROLLED TIME OVERCURRENT WITH INSTANTANEOUS, 1/PHASE
52 CIRCUIT BREAKER
L = LOAD
T = TRANSFORMER
G = GENERATOR
55 POWER FACTOR/VAR CONTROLLER
59 OVERVOLTAGE TRIP
59N GROUND OVERVOLTAGE (UTILITY SIDE)
81-U UNDERFREQ TRIP
81-O OVERFREQ TRIP
94 TRIPPING RELAY
Rn NEUTRAL RESISTOR
Xn NEUTRAL REACTOR
✡ NOT USED FOR INDUCTION GENERATORS OR LINE COMMUTATED INVERTERS
* POWER FACTOR CORRECTION FOR INDUCTION GENERATORS
** REQUIREMENTS DEPEND ON GENERATOR GROUND. & STEP UP TRANS.



NOTE: RELAYS DO NOT HAVE TO BE INDIVIDUAL. FUNCTIONS MAY BE INCORPORATED IN THE INTERFACE PROTECTION PACKAGE, OR AS PART OF AN INVERTER.

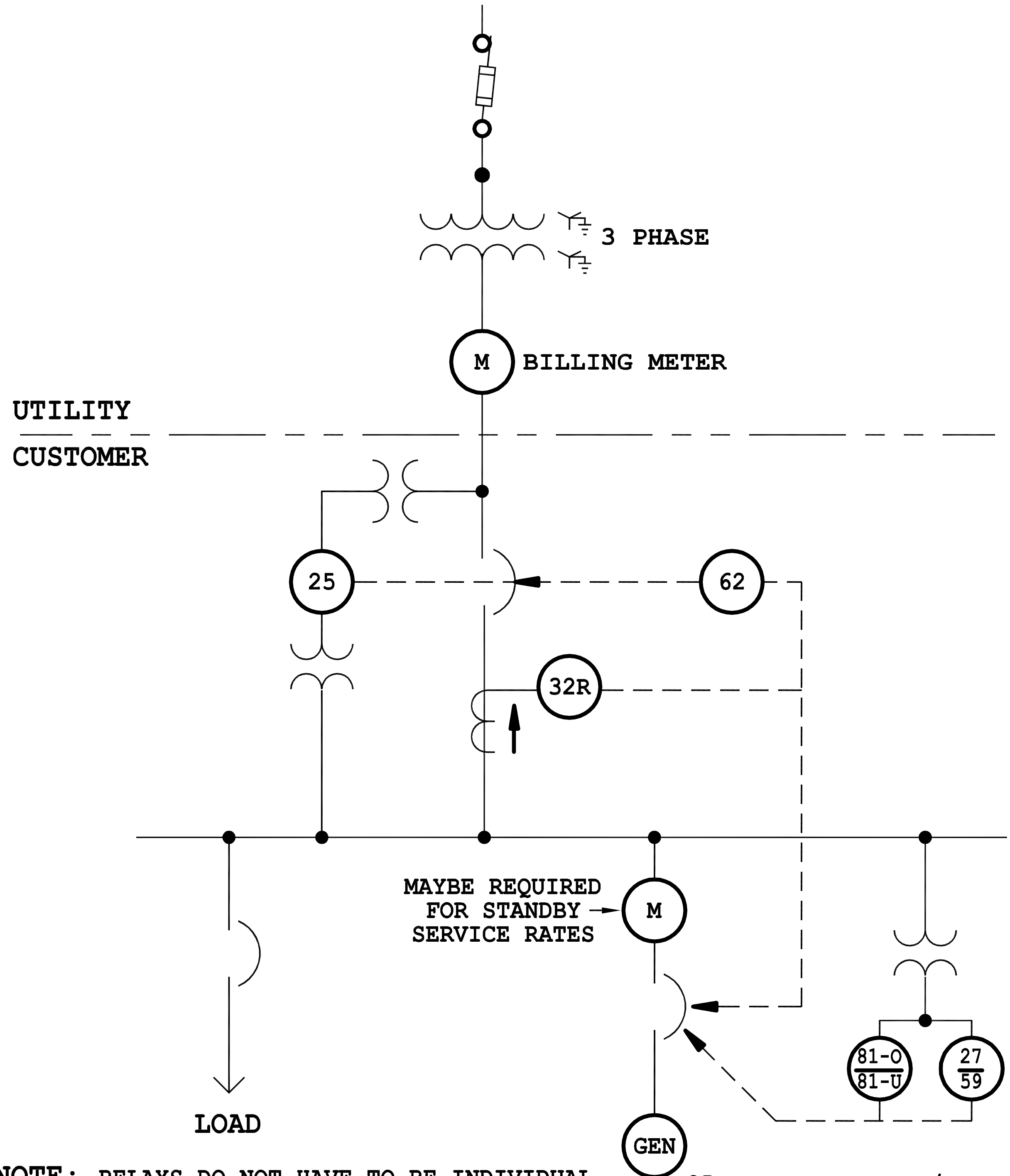
NOT SHOWN:
PRODUCTION METERS
TELEMETRY

3/15/2010

Xcel Energy

TYPICAL PARALLEL GENERATION INSTALLATIONS 1MW TO LESS THAN 10MW URBAN CONDITIONS

FIGURE NO. 10.4



NOTE: RELAYS DO NOT HAVE TO BE INDIVIDUAL. FUNCTIONS MAY BE INCORPORATED IN THE INTERFACE PROTECTION PACKAGE, OR AS PART OF AN INVERTER.

25	SYNCHRONIZER/SYNC CHECK
27	UNDERVOLTAGE TRIP
32	SENSITIVE REVERSE POWER TRIP
59	OVERVOLTAGE TRIP
62	PARRALLEL TIMER TRIP
81-U	UNDERFREQUENCY TRIP
81-O	OVERFREQUENCY TRIP

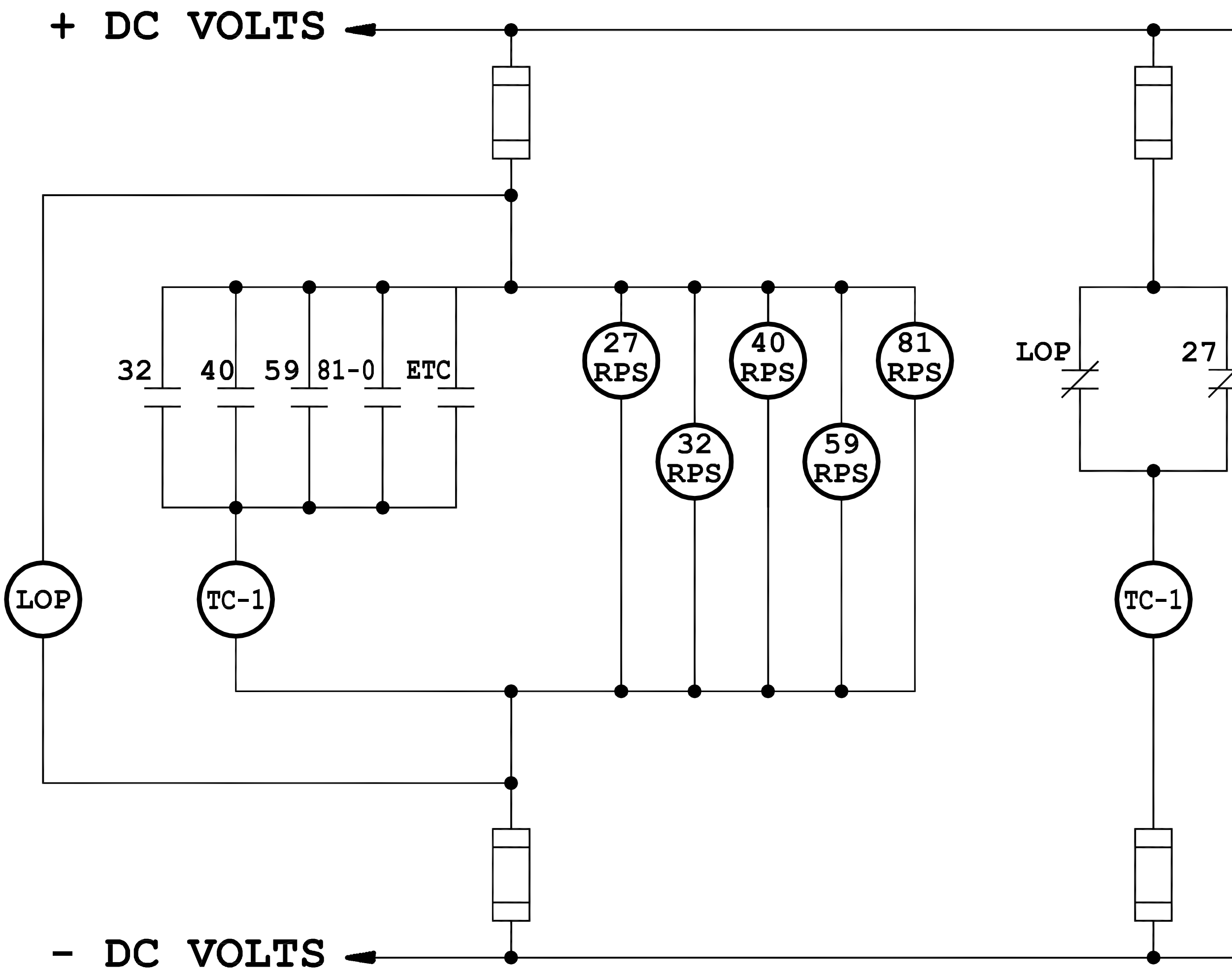
3/15/2010

Xcel Energy

TYPICAL SOFT LOADING TRANSFER

FIGURE NO.

10.5



TC - TRIP COIL
RPS - RELAY POWER SUPPLY
LOP - LOSS OF POTENTIAL RELAY

LOP & 27 CONTACT OPEN WHEN ENERGIZED

3/15/2010

Xcel Energy	EXAMPLE OF SEPERATE FUSING FOR VARIOUS RELAY SCHEMES	FIGURE NO. 10.6