DISTRIBUTED GENERATION

INTERCONNECTION MANUAL

SOUTH DAKOTA

NORTHERN STATES POWER
MINNESOTA

d/b/a

XCEL ENERGY

MAY 21, 2012

DISTRIBUTED GENERATION INTERCONNECTION MANUAL

DISTRIBUTED GENERATION INTERCONNECTION MANUAL

1.0 INTRODUCTION

1.1 GENERAL

Process

The South Dakota Public Utilities Commission (SDPUC) Administrative Rule 20:10:36 sets the process and timelines for interconnection application, review, testing, and approval, see Section 13 link. This Manual, along with the Xcel Energy tariffs and the Xcel Energy Standard for Electric Installation and Use manual supplement the rules. Section 9 of the Company's tariffs provides the Cogeneration and Small Power Production policy.

This Manual primarily addresses the technical requirements of interconnection but it does provide some discussion, guidance, and additional information regarding the interconnection process. The SDPUC Administrative Rule 20:10:36 remains the final authority. The parties can mutually agree to deviations, time extensions, etc. from those stated in the rules and Interconnection Manual except SDPUC Administrative Rule 20:10:36:16, which requires a waiver from the PUC for deviation. The rules address four 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 four levels. Unless specifically stated otherwise, the requirements in this document apply to continuous parallel operation of interconnected Customer generation[1].

The four review levels are:

Tier 1 - For lab-tested Inverter-based Generating Facilities with an AC power rating of 10 kilowatts (kW) or less, under certain conditions.

Tier 2 - For Generating Facilities using lab-tested equipment or field-tested interconnection equipment that pass certain specified screens and have an AC power rating of 2 megawatts (MW) or less, connected to a radial distribution circuit or spot network distribution circuit limited to serving one premise and does not qualify for Tier 1.

Tier 3 - For Generating Facilities that have a power rating of 2 megawatts (MW) or less, meets the specified screens, the proposed point of interconnection is not to a transmission line, does not export power beyond the point of interconnection, utilizes low forward power relays or other protection function that prevents power flow onto the distribution feeder, and does not qualify for Tier 1 or Tier 2. Tier 3 does not require lab-tested equipment.

Tier 4 - For Generating Facilities that have a power rating of 10 megawatts (MW) or less and does not qualify for Tier 1, Tier 2, or Tier 3.

Installations over 10 MW.

South Dakota PUC Administrative Rule 20:10:36:62 requires that facilities rated over 10 MW shall start with the Tier 4 process to guide the interconnection process. Additionally, the technical requirements of the project are required to be based on Tier 4 technical standards and to be modified as needed with agreement between the Company and the Customer. The Company and the Customer should mutually agree upon the process that will be used during the application phase of the project.

[1] Parallel operation in excess of 2 minutes is defined as continuous for the purposes of this manual.

Definitions

Terms used in this document are defined in Definitions Section 11. These terms are intended to carry the same meaning as used in the SDPUC Administrative Rules and in the Institute of Electrical and Electronic Engineers (IEEE) Standard 1547. This standard and other referenced standards are listed in Reference Section 12.

Technical Standards

The SDPUC 20:10:36 Administrative Rules require the use of IEEE 1547 and 1547.1 for the technical requirements, interconnection equipment certification, and commissioning testing. This manual is intended to provide discussion, summarization, and clarification of these standards for use under the SDPUC 20:10:36 Administrative Rules. Some situations are not addressed in the IEEE standards. This document provides the additional details to extend the IEEE standards to these situations. The IEEE standards and SDPUC 20:10:36 Administrative Rules do not address metering, and other details necessary to interconnect successfully. This document will provide additional guidance and details for these aspects[2]. Additional references that may be of use are listed in Section 12.

IEEE 1547 and 1547.1 set the performance requirements for qualifying as lab-tested interconnection equipment[3]. Any interconnection package certified by Underwriters Laboratory (UL) under UL 1741 is accepted as lab-tested equipment by Xcel Energy. Other certification protocols, conducted by a NRTL, to meet the IEEE requirements will be accepted if they are demonstrated to be equivalent. UL 1741 requires a number of safety and application aspects to be demonstrated in addition to the technical aspects and is the preferred testing protocol.

For the purpose of this document, the term "Customer" will be used to refer to cogenerators, qualifying facilities (QFs), small power producers, non-utility generators (NUGs), and customer-owned generators. “Customer” is used to encompass the SDPUC 20:10:36 terms “Interconnection Customer” and “Applicant”. The term “Company” is used to refer to Northern States Power Minnesota, d/b/a Xcel Energy.

This document does not address all of the nuances and complexities involved in designing an interconnection protection scheme. Extensive application, review, and testing guidance can be found in the IEEE 1547.2 guideline. 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 only. IEEE 1547.2, Appendix A provides additional discussion and typical one-line diagrams.

Screening Philosophy and Small Unit Compliance

The SDPUC 20:10:36 Administrative Rules are based on expediting the review of interconnections when size, type, and situation are such that detailed studies are not needed. The “screens” in the rules are meant to define those combinations and circumstances that can be declared safe for interconnection with only brief review and minimal or no utility involvement in commissioning testing. The availability of national standards, such IEEE 1547, recently updated national codes, such as the National Electric Code (NEC), and type tested interconnection products, such as lab-tested inverters, make this a safe and expedited practice.

Most small installations are relatively standardized, will pass the Tier 1 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, lab-tested, inverter-based installations.

[2] See “The Xcel Energy Standard for Electric Installation and Use” for further guidance.
[3] See definition section. Lab-tested equipment is also known as equipment certified by a national recognized testing laboratory to meet UL 1741 and IEEE 1547.1.

With few exceptions, photovoltaic installations rated 10 kW or less will pass the Tier 1 screens. Virtually all inverters manufactured and sold in the USA today are lab-tested, certified inverters. Today, many small wind generation units use lab-tested inverters and will pass the Tier 1 screens also. This means that, unless there are high penetrations of these 10 kW or less units or other generation on a portion of a feeder, they probably will qualify for the Tier 1 review and approval process. <u>If a unit passes the Tier 1 review, it should comply with the balance of this document's technical aspects.</u>

Units that pass the screens 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 a detailed review.

Final Authority

Customers and Company personnel may be guided by this document when planning installations of distribution-connected generation. The final authority remains with the requirements of IEEE 1547, IEEE 1547.1, and the SDPUC 20:10:36 Administrative 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 standards. 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 units. These facilities must apply, be reviewed under, and be approved according to 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 South Dakota rules and this manual.

1.2 POLICY ON INDEPENDENT GENERATION

The Company will allow any Customer, as permitted under SDPUC Administrative Rules and Company tariffs, as approved by the Commission, to operate generating equipment in parallel with the Company electric system whenever this can be done without undue risk or effects on 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 system. These requirements are determined in accordance with the SDPUC 20:10:36 Administrative Rules and the applicable standards and codes. The purpose of these 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 parallel generation. Large facilities will often require the extension or rebuild of a feeder, the addition of interrupting devices, and possibly the replacement of a substation transformer. DGs with directly connected rotating generators will rarely be acceptable on Company spot or secondary networks.

1.3 GENERATION SOURCES

The South Dakota Rules and this document are based upon the generation technology used, not upon the fuel or energy source that is utilized. The end conversion 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. Company phase rotation is ABC counterclockwise in most areas. Customer should verify rotation and voltages with the Company before purchasing any equipment.

A Customer may operate the generator: a) In parallel with the Company or b) As a separate system with the capability of load transfer between the two independent systems. The SDPUC 20:10:36 Administrative Rules or IEEE 1547 do not specifically cover the load transfer mode requirements. The transfer mode requirements are based upon these rules and standards but may have less stringent requirements. Each continuous paralleling mode of operation requires a signed interconnection agreement. Machine based generation that will parallel for less than two-minutes and that will equal or exceed 1 MW of aggregated generation will require a review and a signed interconnection agreement. 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. 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).

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.

Utility lines are subject to a variety of natural (lightning, wind, ice) and man-made hazards. The electric problems that can result from these hazards 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 the 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 all sources.

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 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 condition, the isolated system may continue to operate independent of the Company 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. The general and specific requirements for parallel generation installations of various sizes are discussed in the following sections.

1.6 AUTOMATIC THROW-OVER SERVICE WITH PARALLEL GENERATION

In general, the Company prohibits the use of continuous parallel generation (greater than 2 minutes) behind a Company owned primary voltage Automatic Throw-Over (ATO) equipment. The Company may permit, at its sole discretion, to allow inverter based distributed generation behind a Company owned ATO. The Company may permit, at its sole discretion, to allow closed transition parallel generation (less than 2 minutes) behind Company owned ATO equipment. The Company allows both closed and continuous parallel generation behind Customer owned ATO equipment. This generation is subject to the requirements of this manual. If the Customer chooses to operate continuous parallel generation behind 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.

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 SDPUC Administrative Rules. Tier 1 to Tier 4 are addressed in SDPUC Administrative Rules 20:10:36:26-29. Facilities in excess of 10 MW shall carry insurance as negotiated with Xcel Energy but not less than $1,000,000 per occurrence.

2.0 COMPANY SYSTEM INFORMATION

2.1 VOLTAGE

The Company's most common primary distribution voltages are 12.5 kV, 13.8 kV, 23 kV, and 34.5 kV depending on the geographic area. Other voltages are sometimes used in specific areas. Virtually all of the distribution circuits are designed to be operated "effectively grounded" (see Section 2.3) and are used to provide four-wire distribution (phase to neutral) connected loads. Transmission delivery voltages are 69 kV and 115 kV. 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 (ANSI C84.1-1995 Voltage Range A).

2.2 CIRCUIT RESTORATION

Because most short circuits (faults) on overhead lines are of a temporary nature, it is the Company's practice to automatically reclose our circuit breakers on most distribution lines. Most distribution feeders have one reclose attempt with a 5 second delay (12.5 kV – 23 kV) or 15 second delay (34.5 kV), Some 34.5 kV feeders have automation devices installed and have two reclose attempts with 15 second delays. Upon request, the Company will consider adjusting the existing feeder reclose delay. The company utilizes some sectionalizers and distribution automation for both overhead and underground feeders. These require an automatic delayed reclose. A number of substations are tapped to the transmission lines and are subject to transmission line reclosing. Most transmission lines reclose with no intentional delay. If a delay is used, it is typically 2 seconds. 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 even if a delayed reclose is used. *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>

Most interconnection requirements, and all lab-tested equipment, include over and undervoltage relaying and over and underfrequency relaying. Faster tripping, with smaller delta deviations in frequency and voltage, will speed separation and reduce the possibility of an out of synchronism reclose event. However, the over and underfrequency settings must comply with the North American Electric Reliability Council (NERC) requirements (see Section 5.11), and the over and undervoltage settings must be able to avoid tripping for normal voltage variations and brief, fault-interruption voltage dips.

"Hot Line Reclose Blocking" (HLRB) or sync-check supervision at the reclosing points uses relays to sense if voltage (generation) is present on the line and delays reclosing until the line voltage collapses. Other interlocking methods may also be feasible. *It is the Customer's responsibility to determine the need for reclosing mitigation for the protection of their equipment* and the Customer is responsible for the expense of the Company installing HLRB or other interlocking methods. It is the responsibility of Customers to insure a proper disconnection before the Company reclosing occurs. The hazards and possible remedies for out-of-sync reclosing are discussed in detail in IEEE 1547.2. The Company may require HLRB in cases where high transient voltages can be created that may damage the Company's or other customer's equipment.

2.3 EFFECTIVE GROUNDING

The Company operates an effectively grounded system, as defined by IEEE standards, on most of its distribution 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. A generation facility that does not participate in maintaining effective grounding, upon islanding, can cause severe overvoltages to single-phase loads, resulting in damage. IEEE 1547.2 provides additional discussion on the importance of and methods to address effective grounding and overvoltage limitation. <u>Most smaller, single-phase inverter based generation facilities will not require any additional design consideration to meet this requirement.</u>

This Section is directed at Customers that operate for any extended length of time in parallel with the Company's distribution system. Effective grounding limits the voltage rise on unfaulted phases during single-line-to-ground fault conditions. Inverters must achieve the equivalent limitation of overvoltages as discussed under "Inverters" below. Direct connected rotating generators must comply with the IEEE standard. To achieve effective grounding, a Customer's system equivalent (Thevenin equivalent impedance) must meet the following two criteria (IEEE 32) or otherwise meet a coefficient of grounding of 80%:

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 usually will require the ratio to be between 2.5 and 3.0 ($2.5^*X_1 \leq Xo \leq 3^*X_1$) to limit the adverse impacts on feeder ground relay coordination.*

Synchronous and Induction Generators

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

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

a) A grounded-wye/grounded-wye step-up transformer is common for facilities rated less than 1 MW. When this transformer arrangement is used, the generator must have an appropriately sized grounding bank, or the generator's neutral must be adequately grounded (typically through a grounding reactor) to meet the Company's requirements for effective grounding. Solidly grounding the generator is not recommended since significant generator derating due to unbalanced currents may result. A grounding bank avoids this issue. Wye-wye transformers over 1 MVA should be evaluated for resonant conditions.

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. A neutral resistor may cause high power losses and is not recommended.

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. 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 current and/or voltage imbalance. This configuration should have a switching device to separate the generator and ground source during system separation.

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 without a reactor is not recommended since significant generator derating due to unbalanced currents may result (see IEEE C62.92.1 and C62.92.4).

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 imbalance under 3%[4]. Imbalance may be higher, especially during contingency conditions. The Customer's equipment must be able to withstand allowable imbalances and be able to operate during an imbalance condition.

f) Normal system source impedance data for a given location can be obtained from the Company's Area Engineer. "Normal system" refers to the arrangement of the system most of the time. Due to contingencies and maintenance, field ties are temporarily used and this can change the source impedance and fault duties as seen by a Customer. Changes in both normal and contingency system configurations may be occur without notification 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.

g) The generator reactance used in calculating the ratio X_0/X_1 should be the subtransient direct axis reactance (X_d").

Inverters, Double-fed Induction Generators, and Others

<u>Double-fed</u> 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.

<u>Inverter</u> installations that are large, in single unit or composite facilities should be checked for effective grounding equivalency. IEEE C62.92.1 directly applies to rotating generation and cannot be directly applied to inverters to determine ground referencing equivalency since inverters operate as a current source, not a voltage source. <u>Small, single-phase inverter installations usually do not need to be checked.</u> This requirement applies regardless of the energy source providing power to the inverter. 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 excess voltage (<135% 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.

A three-phase installation comprised of three single-phase inverters connected in a solid grounded wye configuration will usually meet the effective grounding requirement. Single-phase inverters connected in delta will not. Many of the three-phase inverters will not meet the requirement. Some manufacturers employ an internal high resistance between the internal wye and the neutral connection. Some manufacturers connect the inverters in a delta configuration. The presence of a neutral connection on the inverter does not ensure a grounded wye configuration.

Many three-phase inverters use an internal transformer between the AC output and the inverter circuits to provide isolation and voltage matching. Either a delta-wye-grounded or a wye-wye-ground configuration will usually provide adequate ground referencing. If the inverter does not provide adequate ground referencing, either a small grounding bank will be needed, see Figure 10.3, or

[4] See Section 6 of "The Xcel Energy Standard for Electric Installation and Use".

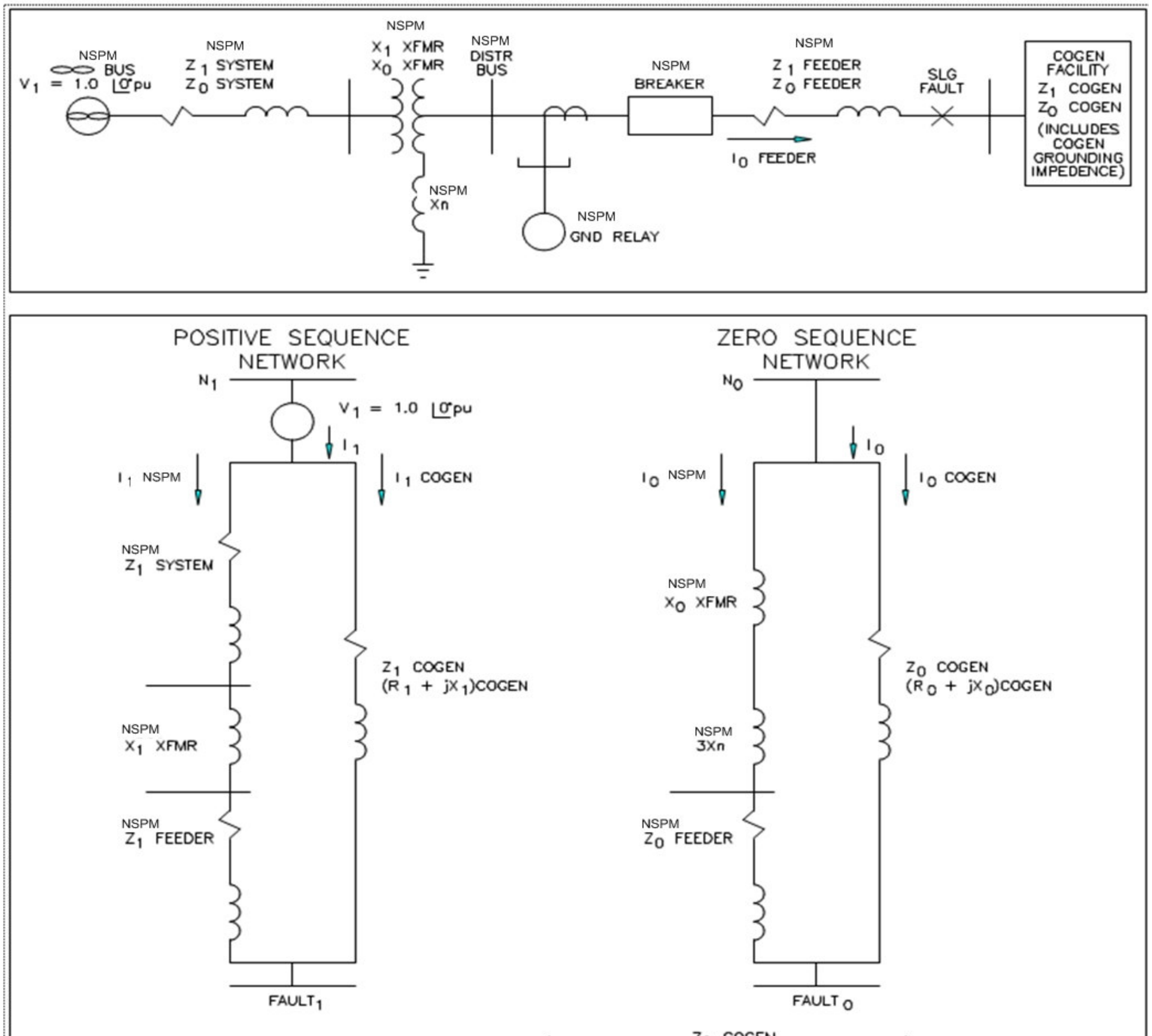
grounding with a wye-grounded-delta with neutral reactor step-up transformer, see Figure 10.4, will be needed.

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 may not be appropriate due to the ongoing losses. A neutral reactor will reduce the imbalance current, operation issues, and losses. A grounding bank avoids this issue and is the recommended approach.

For a typical inverter with a delta-wye output matching transformer, a neutral reactor of about 0.5 per unit reactance inserted in the wye to ground connection will provide suitable ground referencing while minimizing system and inverter impacts.

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

The following diagrams summarize the effective grounding methodology for rotating generation:



$$\text{NSPM ACTUAL GROUND CURRENT} = 3I_0\left(\frac{Z_0\ \text{COGEN}}{Z_0\ \text{COGEN} + X_0\ \text{XFMR} + 3Xn + Z_0\ \text{FDR}}\right)$$

NSPM EFFECTIVE GROUNDING CALCULATIONS
Figure 2.3.1

Company Ground Relays

The Company's ground overcurrent relays located at the substation and on the 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 about 10% to a feeder ground fault, expensive corrective measures *become likely*. 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 often must install additional feeder protection equipment, at the Customer's expense, to ensure a reliable and secure system configuration is maintained. By sizing the grounding equipment to the minimum effectiveness criteria discussed above, adverse impacts to the utility ground relaying is minimize and often mitigating measures can be avoided. The Company may be unable to allow a Customer to add generation to certain feeders due to feeder equipment limitations and/or grounding problems.

Non-inverter facilities under 100 kW (at the Company's sole discretion, see Section 2.4) and all facilities 100 kW and higher must meet the above effective grounding requirements in order to operate in parallel with the Company. A Customer must select equipment such that the impedance and fault levels meet all of the above criteria. For inverter-based facilities under 100 kW, the Company, at its sole discretion, may waive the ground-referencing requirement, see Section 2.4.

2.4 NON-EFFECTIVELY GROUNDED DISTRIBUTION CONNECTED PRODUCERS

A generator under 100 kW may be other than effectively grounded if it can be shown that in all possible situations, where the generator is islanded from the Company and is still generating power, the amount of load that will be on 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. <u>In general, a facility under 100 kW that passes the Screens for Tier 1 or 2 interconnection will qualify for the ungrounded operation option.</u> All inverters connected to spot networks must be effectively grounded on the secondary side.

3.0 SYSTEM INTEGRITY

3.1 GENERAL

The interconnection of the Customer's generating equipment with the Company's system shall not cause any significant reduction in the quality of service being provided to other customers. <u>Lab-tested inverters, unless they are malfunctioning or misapplied, will generally comply with the Section 3 requirements.</u> Lab-tested inverters may not be acceptable without corrective measures, such as filters, for situations where the DG outputs exceed the feeder load. Abnormal voltages, frequencies, harmonics, or interruptions must be kept within limits specified under IEEE 1547, 519, 1453, and 141. If high or low voltage complaints, transient voltage complaints, and/or harmonic (voltage distortion) complaints result from operation of a Customer's generation, such generating equipment shall be disconnected from the Company's system, as permitted under SDPUC Administrative Rule 20:10:36:69, until the Customer resolves the problem. The Customer is responsible for the expense of keeping the generator(s) 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 Harmonic Distortion (THD) from the facility will be measured at the facility's metering point or point of common coupling (PCC). Harmonics on the power system from all sources must be kept to a minimum. Under no circumstances may the harmonic current and resulting voltage distortion be greater than the values listed in Tables 10.3 and 11.1. The Tables below are from IEEE Std. 519-1992[5].

Table 10.3
Current Distortion Limits for General Distribution Systems (120 V Through 69,000 V)

Maximum Harmonic Current Distortion in Percent of I_L						
	Individual Harmonic Order (Odd Harmonics)					
I_{sc}/I_L	<11	11≤h<17	17≤h<23	23≤h<35	35≤h	TDD
<20*	4.0	2.0	1.5	0.6	0.3	5.0
20<50	7.0	3.5	2.5	1.0	0.5	8.0
50<100	10.0	4.5	4.0	1.5	0.7	12.0
100<1000	12.0	5.5	5.0	2.0	1.0	15.0
>1000	15.0	7.0	6.0	2.5	1.4	20.0

Even harmonics are limited to 25% of the odd harmonic limits above.
Current distortions that result in a dc offset, e.g., half-wave converters, are not allowed
*All power generation equipment is limited to these values of current distortion, regardless of actual I_{sc}/I_L.
$I_{sc\,=}$ maximum short-circuit current at PCC (point of common coupling).
$I_{L\,=}$ maximum demand load current(fundamental frequency component) at PCC.
TDD – Total Demand Distortion

Table 11.1
Voltage Distortion Limits

Bus Voltage at PCC	Individual Voltage Distortion (%)	Total Voltage Distortion THD (%)
69 kV and below	3.00	5.0
69001 kV through 161 kV	1.5	2.5
161,001 kV and above	1.0	1.5

NOTE: High-voltage systems can have up to 2.0% THD where the cause is an HVDC terminal that will attenuate by the time it is tapped for a user.

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 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 or cause it to go outside of acceptable limits (ANSI C84.1-1995, 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." Automatic power factor controllers will need to be utilized for most medium and large generation facilities and some small facilities. 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 other than unity power factor, the Company may need to install a capacitor bank in or near the distribution substation, at the Customer's cost, to ensure meeting high voltage delivery point power factor requirements.

[5] See Section 6 of "The Xcel Energy Standard for Electric Installation and Use".

Synchronous Generators

Most synchronous generation units will be required to operate in power factor mode, usually set at unity power factor. A few situations may require operation at other settings in the range of 0.95 leading to 0.95 lagging. Some installations, mostly large installations, may require power factor control set to operated in the 0.95 leading (absorbing) to unity power factor range. Leading power factor operation is most likely to be needed in non-urban areas and for large generators. Operation in automatic voltage regulation mode may be required.

Induction Generators

For induction generators, including double fed induction generators, the generation units must be 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 flicker will occur due to magnetizing inrush current. Voltage flicker will normally be measured at the interface or PCC between a Customer and the Company. However, at the Company's discretion, if voltage flicker problems are found, the measurement may be taken at the nearest possible present or future Company customer.

The interconnection flicker must be within the requirements of IEEE 1547, 519, 1453, and 141[6]. The voltage flicker chart does not address the time duration of the voltage drop. A voltage drop in excess of the standard may be acceptable after consultation with the Company, but a Customer is responsible for any associated damage caused to the equipment of other Company customers. It is suggested that Customers review and comply with the Computer Business Equipment Manufacturer's Association (CBEMA) curve detailed in IEEE/ANSI Standard 446-1987, Section 3.11 (esp. fig. 4), for typical computer sensitivity to very short voltage disturbances. Complaints are rare if the Customer's operation complies with IEEE 446 and 141.

<u>Small generation units may be allowed to operate with minimal power factor correction such as at 0.95 leading.</u> Medium to large induction units must have power factor correction capacitors controlled to bring the unit power factor to near unity.

Inverter Connected Generators

Distribution generation units that interconnect using an inverter are expected to operate at near unity power factor. Large inverter units or large composite groups of inverters will need to be capable of operating at power factor set points in the range of 0.95 leading 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 inverters may introduce significant energization voltage dips. These dips must be within the IEEE 519 limits.

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 Midwest Independent Transmission System Operator (MISO).

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. Even though distribution connected generation is usually not considered FERC jurisdictional, the transmission provider may place operating restrictions on the generation unit(s), such as curtailment during certain system contingencies, or require the generation facilities to pay for minor modifications to the transmission system, such as the use of transfer trip. The Company Engineer will work with the

[6] See Section 6 of "The Xcel Energy Standard for Electric Installation and Use".

Customer to communicate with and comply with the requirements of the transmission provider. In most cases, the transmission provider will be Xcel Energy.

The NERC approved underfrequency load-shedding (UFLS) program requires large distribution connected generation to comply with the UFLS generator tripping requirements. This requirement may restrict the settings available for the anti-islanding underfrequency relaying.

For all generation units, including distribution connected units, above the specified size threshold, over/under frequency protective (device 81 O/U) relaying shall be set to coordinate with the area automatic underfrequency load shedding program (UFLS). The Midwest Reliability Organization (MRO) UFLS program and NERC reliability standard PRC 006 govern the requirements. Generation facilities or units that are nameplate rated 10 MVA or larger must not separate from the system until all load-shedding steps have operated. The lowest load-shedding step from the MRO UFLS program is 58.7 Hz, as of this document's publication date. If tighter generator or interconnection settings are required, the Customer is responsible to arrange for equivalent load to be shed instead.

To improve the distribution anti-islanding protection, the highest frequency, and shortest time delay settings consistent with the above requirements and IEEE 1547 are recommended. Symmetrical overfrequency and times are suggested.

The 2011 National Electric Code, NFPA 70, contains an article that restricts the size of inverter based interconnection into a shared panelboard. Article 705.12(D)(2) states for inverter interconnections: "The sum of the ampere ratings of overcurrent devices in circuits supplying power to a bus bar or conductor shall not exceed 120 percent of the rating of the bus bar or conductor." For a typical 200A residential panel, this means the breaker connecting an inverter based supply, usually a PV system, would typically be rated at 40A or less. A 40A breaker will limit the supply to around 7 kW. A larger supply will require a larger PV system breaker, which could mean replacing the panelboard and meter with higher rated devices. *If compliance is not determined prior to filing the interconnection application, significant delay may occur during commissioning.*

4.2 PROTECTIVE DEVICES

Protective device (relays, circuit breakers, etc.) for the protection of the Company's system, metering equipment, and synchronizing equipment must be installed as required by the Company in accordance with the requirements of the SDPUC 20:10:36 Administrative Rules. The complexity of the protective devices differs with the size of the installation (see Section 5 and Section 10).

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. For generation facilities where the switch is 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 showing the location of the disconnect switch and generation facility.*

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 valid 24/7 for larger installations, but may be the Customer's listed contact number for small installations.

4.4 DESIGN REVIEW AND DOCUMENTATION

The Customer, in accordance with the SDPUC 20:10:36 Administrative 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 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 as a guide to the Customer. The information is tailored to medium to large installations, especially when the interconnection equipment has not been lab-tested. For small installations, especially those using lab-tested interconnection equipment, the documentation needs are minimal.

a) The Customer submits an application as specified in the SDPUC 20:10:36 Administrative Rules. The Company performs a review and approves the design according to the process specified in the SDPUC 20:10:36 Administrative Rules for the size, type, and location of the generation package. A site-plan diagram is required (see Section 15). This package usually includes a proposed 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). 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 SDPUC 20:10:36 Administrative Rules. This 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 as 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 is usually provided on a relaying and metering one-line (and possibly a three-line) diagram. Basic proposed AC and DC schematics or specification of logic may also be provided at this time along with a listing of the proposed specific relays, etc., including information on the manufacturer, model number, relay ranges, etc. See Section 5 for more details on the relaying requirements. The Company requests at least two sets of any design documentation packages. Again, in order to avoid any unnecessary costs associated with changes to the preliminary design plans, this preliminary design information should be submitted to the Company prior to the Customer ordering any equipment, or beginning any detailed engineering work.

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

e) If any changes are made, the Customer should provide the Company a set of revised one-lines, schematics, construction drawings, etc. This is typically an appropriate time for the Customer to supply proposed settings for the interconnection relays, including support documentation (e.g. calculations, fault studies, TOC relay coordination curves, etc.). The Customer may elect to supply at this time the proposed On-Line Test procedure (see Section 7). This needs to be done in advance of the actual testing. Usually, a coordination meeting is held with the Company, the contractors, and the Customer to clarify any questions that may exist before On-Line Testing begins.

f) For facilities greater than 10 kW that do *not* use lab-tested 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 should be given 72-hour notice of any testing or calibration so arrangements can be made for witnessing. <u>Separate test reports are not required for small interconnection packages that have been lab-tested to comply with IEEE 1547.1 by a national registered testing laboratory under UL 1741 or equivalent.</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.

4.5 INDUCTION GENERATORS

For installations with a total generating capacity of 10 kW or less, the Company will supply the VAR requirements from general system sources without a specific charge to the Customer if the full load power factor is 0.9 or higher. Installations over 10 kW capacity will require capacitors to be installed to maintain a power factor of at least 0.95 for smaller units and near unity for larger units over a range of 25% to 100% of output rating (see Section 3.3). Such capacitors and their control will be at the expense of the Customer.

If the reactive power resources exceed the consumption, an induction generator can become self-excited upon separation from the Company source and can produce abnormally high voltages that can cause damage to the equipment of other customers. Overvoltage relays can limit the duration of such overvoltages but cannot control their magnitude. Because of these problems, the reactive power supply for large induction generators, including nearby feeder capacitors, must be studied on an individual basis. In general, self-excitation problems are most likely in rural areas where the Company's system capacity and load density are low and capacitor based voltage support needs are greater.

It is particularly important to contact the Company to determine if an induction generator can be connected to an existing distribution line. Where self-excitation problems appear likely, special service arrangements will be required. In many cases, the additional expense for such special service methods will outweigh the cost savings associated with induction generators. Especially during self-excitation, it is important for a facility to meet the effective grounding requirements to restrict the range of voltage unbalance (see Section 2.3).

4.6 INVERTER SYSTEMS

Reactive power supply requirements for line-commutated inverter systems can be similar to those for induction generators, (see Section 4.5). Since inverters are a harmonic source, Section 3.2 of this document must be followed. Total harmonic distortion (THD) and total demand distortion (TDD) from the facility will be measured at the PCC (point of common connection). The individual inverters must have a TDD of 5% or less and 3% or less is highly recommended.

5.0 SPECIFIC PROTECTIVE RELAYING REQUIREMENTS

5.1 GENERATION CLASSIFICATION

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 SDPUC 20:10:36 Administrative Rules directly address classes 1 - 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 10 MW (large)

5. 10 MW and above (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.

It should be understood that 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 measures to be taken. See section 5.14 for network connected facilities. The review discussed in the following sections applies to the required facility interconnection equipment and does not apply to the balance of the facility.

The relays indicated in Figures 10.1 through 10.5 are for the protection of the Company. In each application, protective relaying 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 lab-tested interconnection packages up to 30 kW normally do not require relay setting determination.</u>

For most installations, utility grade relays are required. Lab-tested interconnection packages are accepted as complying with this criterion. The following manufacturers, as well as other manufacturers, produce utility grade protective relays: GE, ABB, SEL, Basler, and GEC. The following specifies what a utility grade relay should include:

a) Meets or exceeds ANSI/IEEE Standards for protective relays (i.e., C37.90-1989, C37.90.1-1989, and C37.90.2-1995)
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, 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 South Dakota. 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's engineer.

5.2 INSTALLATIONS 10 KW AND UNDER

Except for lab-tested 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)). 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. <u>Most installations in this class feature a lab-tested protection package. Each package will be reviewed to verify that it is lab-tested and applied in a manner consistent with its certification.</u>

The protective relaying details are shown in Figure 10.1 A & B. The installation must be permanently wired into a suitable load center in accordance with the NEC (see Article 690 for PV). A lockable disconnect switch must be provided 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.

5.3 INSTALLATIONS FROM 10 KW TO 100 KW

Except for lab-tested 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 lab-tested 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 lab-tested interconnection packages do not require the full documentation; however, review of relay settings for units over 30 kW is needed.

Those installations that use a lab-tested 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, but not the intent of the requirements, will be allowed. The intent is consistent with IEEE 1547 requirements. The Company must approve all variations. Installations in this class may use either industrial grade relays or utility grade relays.

5.4 INSTALLATIONS FROM 100 KW TO 1 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) are also required. The documentation and review can be reduced if lab-tested interconnection packages are used. For this size range, the proposed relay settings must be provided for lab-tested packages.

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

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.

5.5 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 lab-tested interconnection packages. This is a common practice with photovoltaic sites. The lab-testing process certifies the design and functionality for only the package with its associated energy source. It does not address the increased system impacts that multiple units will have or possible adverse interactions between facilities with different interconnection designs. Because of this, a site with multiple packages must be reviewed and additional protective equipment and field-testing will likely be required.

Many rural systems will not accept this class of generation or may require extensive rebuilding and reinforcement. The Customer may have 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.

5.6 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 (69 kV) or transmission (115 kV) system. Distribution facilities in excess of 10 MW shall use the SDPUC 20:10:36 as the basis for the interconnection process. Installations over 10 MW are more likely to be FERC jurisdictional and must be reviewed under the FERC SGIP.

5.7 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. 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 5.9. Since this type of installation often employs a sensitive direction power relay to aid in separation, some of the interconnection requirements may be relaxed.

5.8 DEMAND REDUCING GENERATORS

A Demand Reducing Unit (sometimes referred to as a "peak shaving" unit, where the local demand is reduced) is one where a Customer is paralleled with the Company but no power is intentionally shipped to the Company and the Company purchases no power. These may be eligible for Tier 3 review. 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 the Company's system. The size classification (see Sections 5.2 through 5.6) will be determined from the generator's rating and if more than one generating unit is at the site, all of the generator's 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.

5.9 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. 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. For large installations, the timer and trip path shall be a separate relay independent of the transfer switch or switchgear transfer control. At the sole discretion of the Company's engineer, small installations using UL Listed transfer switches may use the timer that is part of the control 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.

5.10 HIGH SPEED TRANSFER SWITCHES

A high-speed transfer switch with switching times of less then 500 ms is classified as a High Speed Transfer System. Because of the complexities in the high speed transfer switch(s); each installation will need to be reviewed on a case-by-case basis. In addition, assuming the Company has not previously reviewed the proposed model of high-speed transfer switch, the Customer is to provide the Company with documentation of the switch's ratings, manufacture's drawings of the switch, and the manufacture's specifications for the switch. Due to the high speed, if suitable interlocks and synchronism check features are present, no further requirements may be needed.

5.11 SYNCHRONIZING/SPEED MATCHING

Synchronous Generators

Synchronizing relays are more for the protection of the Customer's equipment than for the protection of the Company. The Company will review the settings of the Customer's synchronizing relaying to verify the settings are within the guidelines of IEEE 1547, Table 5. However, the Company cannot take responsibility for the appropriateness of any given setting for a Customer's synchronizing relaying. It is highly recommended that a 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 lab-tested 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. In other words, the Customer is not allowed to close their breaker at the common point of connection when the Company's feeder is de-energized. 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, 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 to have synchronizing similar to synchronous generators.

For larger induction generators (typically above 100 kW) a mechanical speed matching relay (device 15) set to accept mechanical speed within $\pm$3% of 60 Hz, with <1% being preferred, is recommended as a means of limiting voltage flicker. The largest effect on the system of bringing an induction generator to synchronous speed is the voltage dip associated with the magnetizing inrush current.

5.12 GOVERNOR DROOP REQUIREMENTS

All medium to large units with active governors should be operated in automatic. To provide equitable and coordinated system response to load and generation imbalances, governor droop should be set at 5% 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.

Governor droop is the percent decrease in frequency to which a governor responds by causing a generator to go from no load to full load. The definition of governor response is more precisely defined as "speed regulation" which is expressed as a percent of normal system frequency. For instance, if frequency decays from 60 to 57 hertz, a 5% change, a generator at zero load with a governor set at a 5% droop would respond by going to full load. For smaller changes in frequency, changes in generator output are proportional.

5.13 DC FUSING

Larger 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 tempting. Adequate protection for the loss of a DC fuse should 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 should 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.

5.14 LAB-TESTED INVERTERS CONNECTED TO A NETWORK

The SDPUC Administrative Rules 20:10:36:32-33 rules address the Tier 1 process for interconnection of lab-tested inverters to distribution spot networks and shared secondary networks. The SDPUC Administrative Rule 20:10:36:37 addresses the Tier 2 process for interconnections of lab-tested inverters to distribution spot networks. The facilities that pass the screens for 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. IEEE 1547.6 "Recommended Practice for Interconnecting Distributed Resources with Electric Power Distribution Secondary Networks" should be consulted and applied.

Unless the network protectors are certified for out of step operation, rotating machines are not allowed. Network protectors presently available do not have out-of-step voltage withstand ratings. For rotating generator interconnections, network protectors may fail catastrophically. When suitable network equipment becomes available, interconnection may be considered with a change-out of any existing network protectors involved, at customer expense. IEEE 1547.6 provides guidance for interconnection of DG with networks.

Applications with less than the above minimum load ratio will require the following protective relaying requirements:

- Minimum Load Relay: Trip the Generation instantaneously if generation rated output exceeds 25% of the actual service load or;.
- Comparative relaying system: Prevent the Generation output from exceeding 50% of the service demand.
- All protective relaying systems proposed by customer shall be evaluated for approval by Xcel Energy.

If a For facilities larger than the screening thresholds, interconnection of lab-tested inverter facilities may be feasible. Additional protective relaying is not required if:

- Minimum load > 20 times the generation nameplate as measured instantaneously
- Exception requires previous 12 months of data and is subject to revocation if conditions are no longer met.

If the spot network serves a single customer and that customer accepts the possible reduction in service reliability, then consideration of a larger interconnection will be considered. A successful interconnection will be designed to operate such that at no time does the generation exceed 80% of the load after subtracting the single biggest branch load. Any network connection over 50% of load will likely require dynamic control of the PV inverter output to shave output under certain conditions. Dynamic inverter output control is definitely needed if generation can exceed the 80% margin for any part of the year.

All equipment providing supplemental relaying functions for lab-tested inverters connected to networks shall meet or exceed ANSI/IEEE Standards for protective relays, i.e. C37.90, C37.90.1 and C37.90. Any DG above the SDPUC Administrative Rules 20:10:36:32-33 rules screen limits desiring interconnection to a shared secondary network or a multi-party spot network may be required to provide remote monitoring.

6.0 METERING REQUIREMENTS

6.1 GENERAL

Metering installation requirements for the different categories of Customer-owned parallel generators are the same as those outlined in 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 contain metering pulse recorders, the Customer may be required to provide a phone line to the site for remote interrogation of the recorder.

6.2 METERING TARIFFS

Section 9 of the Company tariffs provides the Payment Schedule for Energy Delivered to the Company for facilities in E50 and E52.

The Tariffs also specify the requirements, conditions, and cost methodology for the Company to provide standby, supplementary, emergency, and incidental service rates to the Customer, see tariff Section 6. The Customer should consult the Company tariffs, as approved by the SDPUC, 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 and perform meter reading and processing. For most situations, these added costs are the responsibility of the Customer. The Customer should consult the Company tariffs, as approved by the SDPUC, to determine the details, conditions, and rates that apply to their situation.

7.0 DEMONSTRATION OF PROTECTIVE DEVICES

7.1 GENERAL

Customers are to demonstrate the correct operation and functionality of the interface protective devices. <u>Only a simple, operation demonstration may be needed for small, lab-tested protective packages.</u> Some additional demonstration for larger lab-tested packages may be required. The Company is not responsible for performing this demonstration. Customers must provide qualified electricians, technicians, and operators, as needed, to perform the demonstrations. The Customer must supply all personal protective equipment required and designate any procedures necessary to ensure that appropriate safety precautions are taken while working near energized equipment. The scheduling of this demonstration should be coordinated to comply with the time frames specified in the SDPUC 20:10:36 Administrative Rules. A 72-hour notice is preferred. 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 will be determined by the Company's engineers.

The commissioning testing and demonstration shall be conducted in accordance with the requirements of IEEE 1547.1. IEEE 1547.2 provides additional information to consider for commissioning testing. The following provides additional discussion that may be of use in devising and performing these tests. *This discussion is focused primarily on the needs of large facilities* and a number of the steps and tests can be skipped for medium to small facilities. <u>Facilities using lab-tested interconnection packages have abbreviated commissioning needs as many aspects have already been covered under the type-testing required for certification.</u>

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

The following Calibration, Trip Checks, and On-Line Testing sections are intended to serve as a suggested approach. The actual demonstration will depend upon the specifics of the installation, final approved AC/DC schematics, relay settings, etc. These testing procedures are intended to be non-destructive but the Company will not be liable for any equipment damage or injury resulting from the use of these testing procedures. The Customer is responsible to demonstrate the operation of all interconnection protective devices in a safe manner that does not adversely affect the Customer or Company equipment.

7.2 CALIBRATION

<u>CT's:</u> Visually check polarity mark orientation on all CT's with respect to the three-line diagrams in the design drawings, the manufacturer's drawings, and the bridging philosophies. Perform polarity checks of the CT's per ANSI Standard C57.13-1993.

The following CT tests should be performed:

- Verify the CT polarity electrically relative to the polarity marks (physical), the bridging direction (electrical), and the drawings.
- Verify that all grounding and shorting connections and test blocks provided make good contact.
- CT single point grounding shall be confirmed for each CT circuit as shown on the drawings, with the preferred grounding location at or near the relay panel.
- Ratio check CT's at all taps.
- Perform Megger® tests on all CT's to ground.
- Perform demagnetization and excitation tests on CT's as the final tests on CT's.
- Check excitation test data against CT excitation curves.
- All CT's should remain shorted until testing procedures show the CT's are properly loaded. Once testing has been completed, make sure all appropriate CT secondary terminal block shorting screws are completely removed.

<u>VT's, PD's, CVT's, and CCVT's:</u> Visually check polarity mark orientation on all VT's, PD's, CVT's, and CCVT's with respect to the three-line diagrams in the design drawings and the manufacturer's drawings. Test all polarities per ANSI Standard C57.13-1993.

- Verify polarity electrically relative to polarity marks.
- Verify ratio at all taps.
- Verify VT, PD, CVT, and CCVT circuit single point grounding as shown on the drawings.

- Doble® power factor test all VT's, CVT's, and CCVT's.
- Adjust the potential devices (PDs) for the voltage and the burden of the secondary circuits to which they are being connected.

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

7.3 TRIP CHECKS

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

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

a) Verify that breaker(s) cannot be manually or automatically closed with the trip relay in the latched or trip position.
b) Demonstrate that both the synchronism check and synchronizing relays' wiring is correct and that the interlocks operate correctly. Note - to be checked during the On-Line Tests.
c) Demonstrate that the interlocks between the generator and the Company's breakers operate properly; i.e., Customer cannot energize a dead line and can only tie to a hot line via a synchronizing device.

7.4 ON-LINE TESTS

This section describes typical test procedures. The specific test procedure will be tailored by the type and size of the specific facility. It is the responsibility of the Customer to supply the actual written test procedure, which incorporates the following type of tests, to the Company for review before actual On-Line Testing. The procedures are targeted at large facilities that do not use lab-tested interconnection equipment. The procedures do not need to be this complete when lab-tested equipment is used. Small facilities with lab-tested interconnection equipment may need only simple on-line testing.

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

Items "a" through "f" should be performed with the generator breaker 52G racked out in the test position and the line breaker 52L/T closed (see Figures 10.3 through 10.4 for breaker designation), energizing the transformer.

a) Voltage Relay. Device 27: Before putting the generator on-line, lift the potential to the relay. Expected result is the operation of Device 27 after the specified time delay.
b) Ground Voltage Relay. Device 59N: Verify proper voltage present at relay input (relay may not be applied to smaller generation units).
c) Frequency Relay. Device 81 O/U: Verify proper voltage present at relay input.

d) Phase Sequence and Voltage Balance Relay. Device 47 (or 47/27): Interchange two of the potential inputs to this relay to simulate a negative (reverse) phase sequence condition. Expected result is the operation of this relay after the specified time delay. Also, lift one potential lead and observe relay trip output. Once testing of this device is completed, restore the potential input connections to their original polarities. An alternative test is to perform a relay "phase-out" by checking the voltage inputs to the relay for proper magnitude and phase angle relationship with a phase angle meter, and voltmeter.

e) For synchronous generators, phase-out and check the rotation of the primary potential on both the incoming and running sides of the generator breaker with the generator running unloaded, i.e., between the generator and the Company. The primary phase-out voltage measurements are typically performed using two sets of hot sticks (supplied by the Customer's testing group) to verify zero voltage across the generator poles on two phases simultaneously. While performing the phase-out and rotation check, test phasing and rotation across the open generator breaker using syncroscope and voltmeter for VT secondary verification. Verify a single sync path exists through the sync-select switch on the multi-unit operations. With the generator breaker still racked out in the test position, verify that the speed matching/synchronizer (15/25) in conjunction with the sync-check (25x) relay gives a breaker close output at the appropriate synchronized conditions (proper voltage magnitude match, phase rotation, phase angle match, and proper slip rate).

f) For induction generators, allow the prime mover to rotate the generator with generator breaker open. Then, with the prime mover removed and stopped, use a suitable voltage to bump the machine to verify electrical rotation. Expected result is the same direction of rotation.

g) Shut off the generator, open the line breaker, and rack in the open generator breaker. Close the line breaker, start up the generator, and synchronize the generator to the Company's energized transformer. Verify that acceptable minimal flicker occurs at the close of the generator breaker and that the generator runs in a stable unloaded condition in parallel with the Company. Synchronizing should normally take place while the sync-scope is moving in the "fast" direction (generator faster than system) but this is not required. A power quality analyzer (supplied by Customer's testing group) should be used to verify proper breaker pole alignment and voltage flicker, (see Section 3.3). Voltage and current harmonics from the generator should also be measured and must fall within the IEEE 519 harmonic limits (see Section 3.2) at the point of common coupling.

h) Reverse Power Relay. Device 32: With the generator on-line, cause the generator to motor. Expected result is the operation of Device 32 after the specified time delay. An alternate test is to perform a relay "phase-out", under load, at the directional relay, by checking the voltage and current inputs to the relay for proper magnitude and phase angle relationships using a phase angle meter, voltmeter and ammeter.

i) Overcurrent Relay. Device 51V: With the generator on-line, run the generator above the zero voltage current pick-up level with voltage applied; lift the potential. Expected result is the operation of Device 51V after the specified time delay.

j) Differential Relays. Device 87B, 87T: With appropriate precautions made so as to not trip the unit off line during testing, measure the secondary currents (magnitude and phase angle) coming to the relay (and CT summation cabinet for 87B), from each CT, and measure appropriate relay differential and restraint currents. For 87B relays, also measure voltage across appropriate relay voltage element (e.g., 87L operate element). Verify proper operation of associated 86 lockout relay(s) etc.

k) Power Factor Controller Test. This test is typically applicable only for Customers that are rated less than 10 MW and connected to distribution feeders. This test should be done with plant load that can be interrupted during test procedures. Many PF controllers (e.g., Basler) typically have a bias limit adjustment that may need to be adjusted to assure the voltage regulator operates in the proper voltage control range. The bias limit must be set to greater than approximately 30%.

    1. With the generator off-line, measure the power factor (PF) of the full house power kW load. The measured value will usually be lagging, not unity.
    2. Set the generator PF controller to a more leading PF (usually unity) this creates a VAR mismatch between the load and generator. Also, temporarily block the 81 O/U relay.
    3. Bring the generator on-line. The generator should serve the station service load.
    4. Match the generator kW to the house power load.
    5. Trip the line breaker.

6. The generator should trip on low voltage due to PF mismatch by means of the undervoltage relay.

l) A demonstration of compliance with the contracted PF should be performed for induction generators and inverters.
m) Upon the completion of On-Line Tests and final verification of relay settings applied to the specified Customer's relays, these relays should be sealed.

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

8.0 GENERAL OPERATING REQUIREMENTS

8.1 DE-ENERGIZED CIRCUITS

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.

8.2 OPERATIONAL LOG

Customers shall maintain an operating log at each generating facility 100 kW and over indicating changes in operating status (available or unavailable), maintenance outages, trip indications, or unusual conditions found upon inspection.

8.3 FACILITY GENERAL REQUIREMENTS

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

a) For greater than 100 kW, voice communication to the facility via public telephone lines or mutually agreed upon circuits.
b) For all, name and telephone number of the designated operating agent.
c) For greater than 500 kW, familiarity by Customer’s designated operating agent and other operating personnel with the Company’s line clearance and operating procedures.

8.4 TELEMETRY

1 MW and Greater

a) Customer facilities 1 MW and greater will require that telemetry be provided as part of the required system modifications. This does not apply to facilities that qualify for closed or soft load transition status. Additional information can be found in SDPUC Administrative Rule 20:10:36:65.
b) The Information required will vary by location and unit size but will include near real time active and reactive power, unit connection status, and hourly 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 in excess of

the distribution load, or is in an area with a high penetration of generation, more stringent monitoring and control may be required.

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 such as facilities over 5 MW. This control is needed to quickly address 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, tariffs on file, and the provisions stated in the operating attachment to the Interconnection Agreement.
e) The Company either will provide the specifications for the equipment or the needed equipment, at cost, to the Customer.
f) The Customer is expected to provide suitable floor space in a suitably environmentally controlled location.
g) The Customer is expected to provide the communications channel to the Company's dispatch facility or other designated location.

Under 1 MW

a) The Company may require the ability to remotely monitor the output of intermediate size installations. This information is needed to quickly address transmission constraints and contingency conditions, as required by NERC reliability standards, which must be addressed quickly. This does not apply to facilities that qualify for closed load transition status. Additional information can be found in SDPUC Administrative Rule 20:10:36:65.
b) The Information required will vary by location and unit size but will include real and reactive power and unit connection status. Whenever the Customer is located in a transmission 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.
c) The Customer is expected to provide suitable space for the installation of the monitoring and telemetry equipment.
d) The Customer is expected to provide the communications channel to the Company's dispatch facility or other designated location.

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 SDPUC 20:10:36 Administrative Rules require the Customer to 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.

For larger installations, the Customer should perform functional testing of all breakers, relays, and transformers yearly. Installations should have a full relay calibration check performed every three years or less by qualified.

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 will be required. Replacement of lab-tested interconnection packages of like rating generally does not constitute a modification assuming use of the same settings.

Any "Field Modification" or "As Built" AC/DC protection and synchronizing schematics associated with any interconnection device shall 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 lab-tested interconnection packages.
10.1B Typical parallel generation interconnections not using lab-tested interconnection packages.

10.2 10-100 KW

10.2A Typical parallel generation interconnections not using lab-tested interconnection packages.
10.2B Typical parallel generation interconnections with lab-tested interconnection packages.

10.3 100 KW – 1 MW

10.3A Typical parallel generation interconnections not using lab-tested interconnection packages.
10.3B Typical parallel generation interconnections with lab-tested interconnection packages.

10.4 1 – 10 MW

Typical parallel generation interconnections not using lab-tested 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 defined 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 SDPUC Administrative Rule 20:10:36:02 Definitions. If a conflict arises in these definitions, the meaning shall be consistent with SDPUC Administrative Rule 20:10:36:02 in reference to interconnection process matters and IEEE 1547 in reference to interconnection technical requirements.

Business Day - Monday through Friday, excluding Federal holidays.

Lab-tested Equipment Package – aka Lab 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 1547.1. Most equipment is tested under the protocol and requirements of UL 1741. "Type-Certified" is the same as "pre-certified" and "lab-tested" when used in this text.

Company – Northern States Power Minnesota d/b/a Xcel Energy – electric distribution system that serves distribution customers. 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 and that duration is limited by built in timer and/or interlocks. Any operation in parallel that is not limited by built in timer and/or interlocks is treated as continuously parallel regardless of actual duration.

Distribution Upgrades - The additions, modifications, and upgrades to the Company's distribution system at or beyond the point of interconnection to facilitate interconnection of the Generating Facility and render the service necessary to effect the interconnection customer's operation of on-site generation. Distribution upgrades do not include interconnection facilities.

EDS – Electric 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 levels at which distribution systems operate differ among areas.

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.

Field Tested Equipment – Interconnection equipment that is identical to equipment that was approved, by the public utility that interconnection is being requested from, for another interconnection under a Tier 4 study review and has successfully completed a witness test within 36 months from the date of the submission of the current application.

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"

High Speed Transfer Switch – aka Quick Close - 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 then 500 msec with the Company.

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 Customer – A person with a small generator facility that is interconnected to a public utility in accordance with SDPUC Administrative Rule 20:10:36.

Interconnection Facilities – The facilities and equipment required by the electric utility to accommodate the interconnection of a small generator facility to the public utility's EDS and used exclusively to interconnect specific small generator facility. Interconnection facilities do not include system upgrades that may benefit the public utility, other customers, other interconnection customers, or an owner of an affected system.

Lab-tested Equipment – aka Lab Certified Equipment - Interconnection equipment which has been tested by the original equipment manufacturer in accordance with IEEE 1547.1 and found to be in compliance with the appropriate codes and standards referenced therein and is labeled and listed by an NRTL. For interconnection equipment to gain status as lab-tested equipment, its use must fall within the use or uses for which the interconnection equipment is labeled and listed by the NRTL, and the generator or other electric source being utilized must be compatible with the interconnection equipment and consistent with the testing and listing specified for the type of interconnection equipment.

Line Section - That portion of a public utility's EDS connected to an interconnection customer bounded by automatic sectionalizing devices or the end of the distribution line.

Minimum Daytime Loading - The lowest daily peak in the year on the Line Section.

Network System - A collection of Spot Networks, Secondary 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.

National Recognized Testing Laboratory – aka NRTL – A testing laboratory that has met the OSHA criteria for a NRLT such as UL.

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 distribution customer or DG facility is connected to the Company's distribution 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.

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.

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.

Shared Secondary Line – A service line subsequent to the public utility's primary line that has an operating voltage of 480 volts or less 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.

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 type of electric distribution service that uses two or more inter-tied transformers protected by network protectors to supply an electrical network circuit. A spot network may be used to supply power to a single customer or a small group of customers.

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 – aka System 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 (2000), "IEEE Standard Dictionary of Electrical and Electronic Terms"

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

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

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

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

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

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

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 1547.6 (2011), “Recommended Practice for Interconnection Distributed Resources with Electric Power Systems Distribution Secondary Networks”

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

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

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

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

ANSI C62.1, “Surge Arresters for AC Power Circuits”

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

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

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

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

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

NESC – “National Electrical Safety Code”, ANSI C2-2012, Published by the Institute of Electrical and Electronics Engineers, Inc

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

13.0 PUBLIC UTILITY COMMISSION RULES AND XCEL ENERGY TARIFFS

13.1 LINK TO SOUTH DAKOTA PUC RULES FOR SMALL GENERATOR INTERCONNECTION FACILITIES

http://legis.state.sd.us/rules/DisplayRule.aspx?Rule=20:10:36

13.2 SPECIFIC SDPUC ADMINISTRATIVE RULES OF INTEREST

20:10:36:31-35 - Tier 1 DG interconnection Rules

20:10:36:36-41 - Tier 2 DG interconnection Rules

20:10:36:42-49 - Tier 3 DG interconnection Rules

20:10:36:50-61 - Tier 4 DG interconnection Rules

20:10:36:62 - >10 MW DG Rules

13.3 LINK TO XCEL ENERGY TARIFF SHEETS

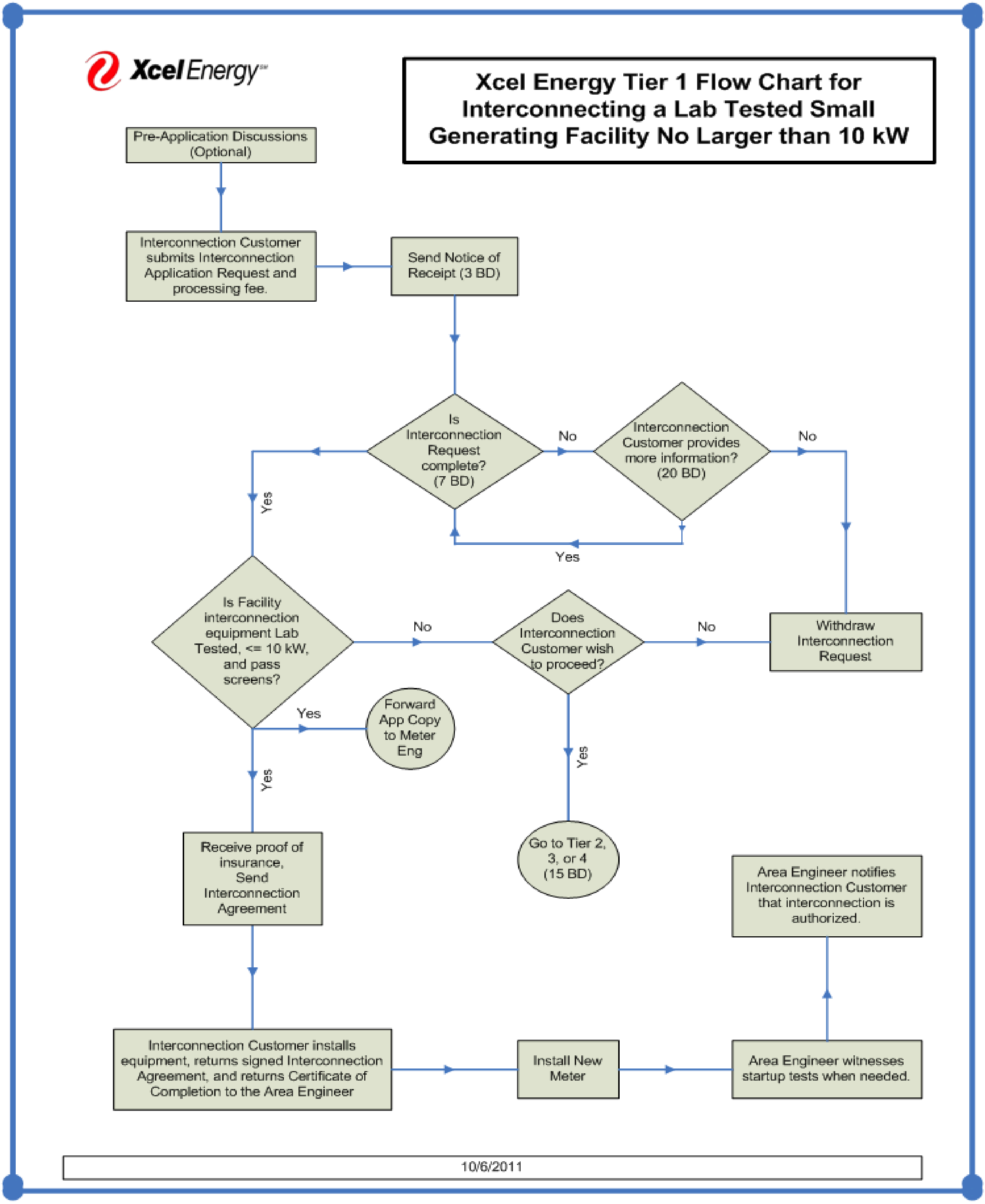
http://www.xcelenergy.com/About_Us/Rates_&_Regulations/Rates,_Rights_&_Service_Rules/SD_Regulatory_Rates_and_Tariffs

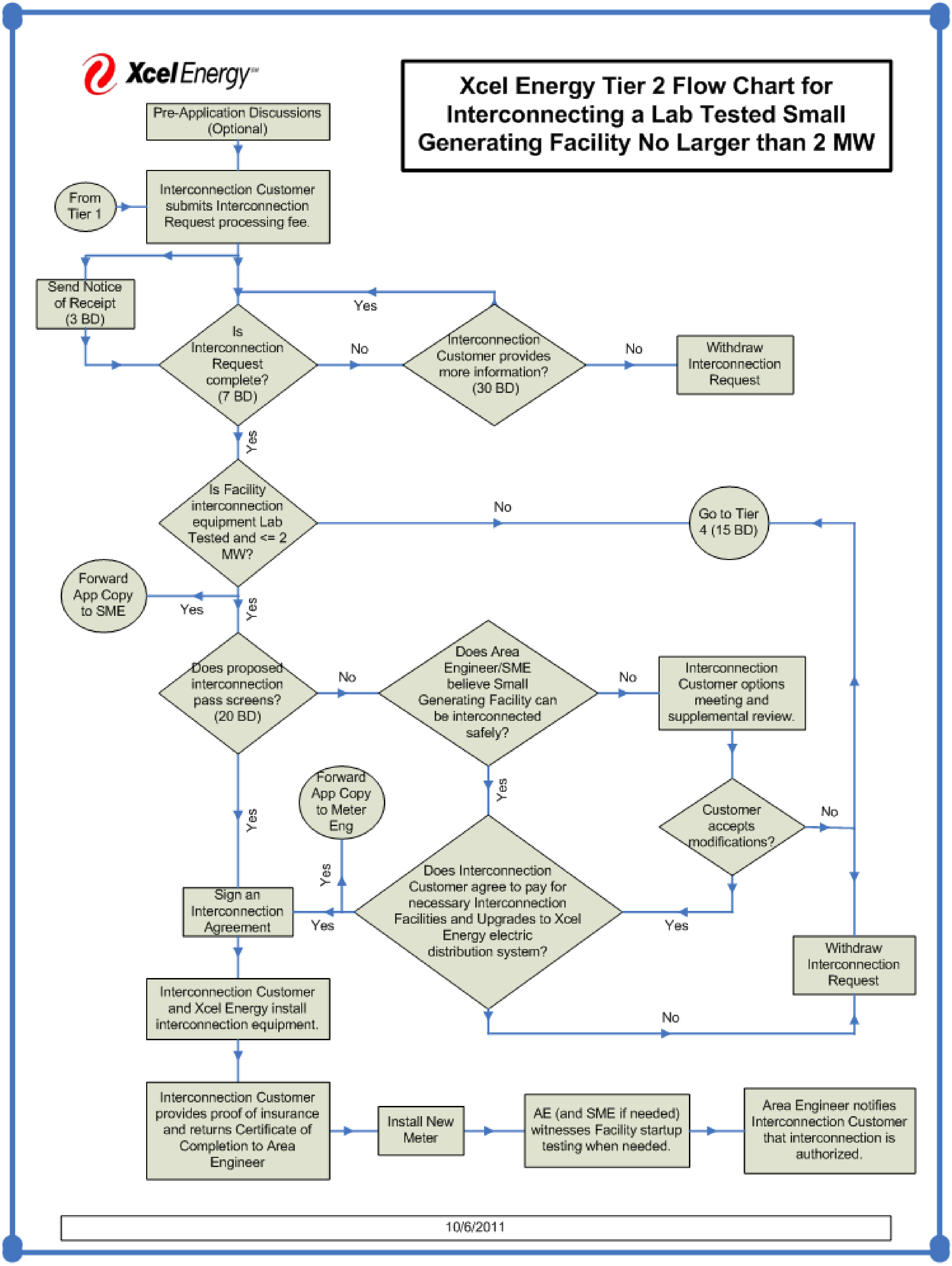
13.4 SPECIFIC TARIFF SHEETS OF INTEREST

Section 6 General Rule and Regulations: Section 2.4 Standby, Supplementary, Emergency, and Incidental Services

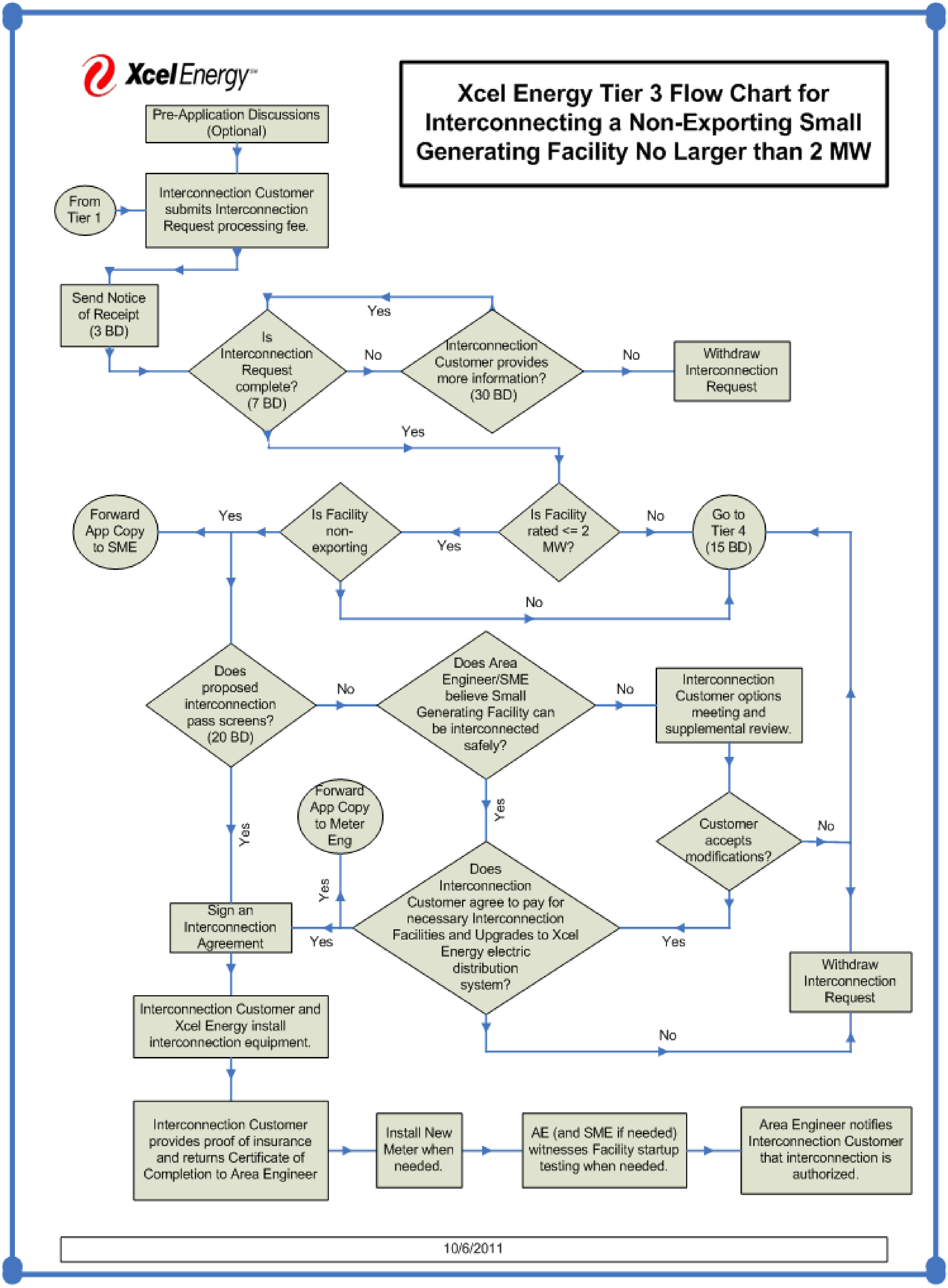
Section 9 Cogeneration and Small Power Production

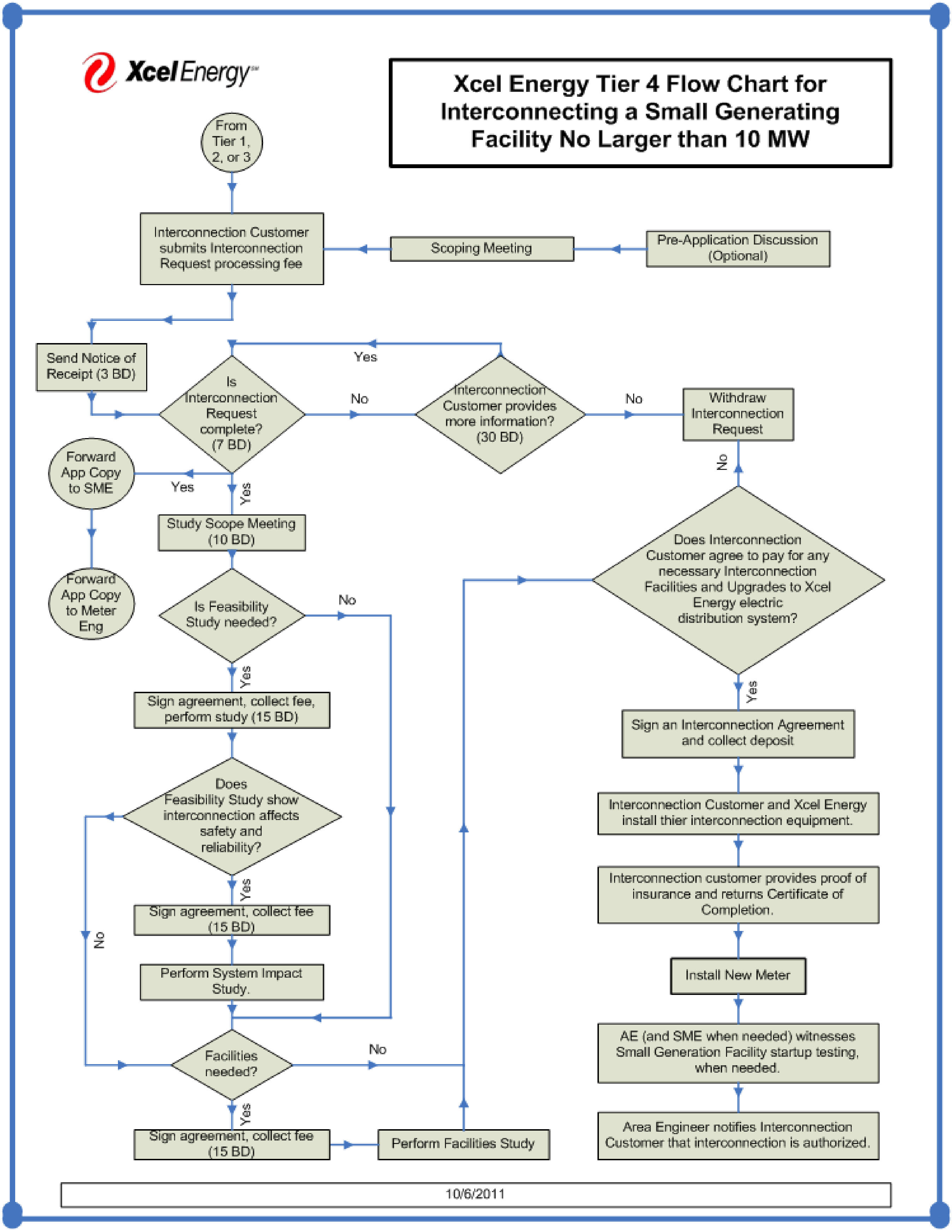
14.0 PROCESS FLOW CHARTS




Xcel Energy
Xcel Energy Tier 2 Flow Chart for Interconnecting a Lab Tested Small Generating Facility No Larger than 2 MW
Pre-Application Discussions (Optional)
From Tier 1
Interconnection Customer submits Interconnection Request processing fee.
Send Notice of Receipt (3 BD)
Is Interconnection Request complete? (7 BD)
No
Interconnection Customer provides more information? (30 BD)
Yes
No
Withdraw Interconnection Request
Yes
Is Facility interconnection equipment Lab Tested and <= 2 MW?
No
Go to Tier 4 (15 BD)
Forward App Copy to SME
Yes
Yes
Does proposed interconnection pass screens? (20 BD)
No
Does Area Engineer/SME believe Small Generating Facility can be interconnected safely?
No
Interconnection Customer options meeting and supplemental review.
Yes
Yes
Forward App Copy to Meter Eng
Yes
Customer accepts modifications?
No
Sign an Interconnection Agreement
Yes
Does Interconnection Customer agree to pay for necessary Interconnection Facilities and Upgrades to Xcel Energy electric distribution system?
Yes
Withdraw Interconnection Request
No
Interconnection Customer and Xcel Energy install interconnection equipment.
Interconnection Customer provides proof of insurance and returns Certificate of Completion to Area Engineer
Install New Meter
AE (and SME if needed) witnesses Facility startup testing when needed.
Area Engineer notifies Interconnection Customer that interconnection is authorized.
10/6/2011

Xcel Energy Tier 3 Flow Chart for Interconnecting a Non-Exporting Small Generating Facility No Larger than 2 MW




Xcel Energy
Xcel Energy Tier 4 Flow Chart for Interconnecting a Small Generating Facility No Larger than 10 MW
From Tier 1, 2, or 3
Interconnection Customer submits Interconnection Request processing fee
Scoping Meeting
Pre-Application Discussion (Optional)
Send Notice of Receipt (3 BD)
Is Interconnection Request complete? (7 BD)
Yes
No
Interconnection Customer provides more information? (30 BD)
No
Withdraw Interconnection Request
Forward App Copy to SME
Yes
Yes
Study Scope Meeting (10 BD)
Forward App Copy to Meter Eng
Is Feasibility Study needed?
No
Yes
Sign agreement, collect fee, perform study (15 BD)
Does Feasibility Study show interconnection affects safety and reliability?
Yes
No
Sign agreement, collect fee (15 BD)
Perform System Impact Study.
Facilities needed?
No
Yes
Sign agreement, collect fee (15 BD)
Perform Facilities Study
Does Interconnection Customer agree to pay for any necessary Interconnection Facilities and Upgrades to Xcel Energy electric distribution system?
No
Yes
Sign an Interconnection Agreement and collect deposit
Interconnection Customer and Xcel Energy install thier interconnection equipment.
Interconnection customer provides proof of insurance and returns Certificate of Completion.
Install New Meter
AE (and SME when needed) witnesses Small Generation Facility startup testing, when needed.
Area Engineer notifies Interconnection Customer that interconnection is authorized.
10/6/2011

15.0 FEE SCHEDULE

Application Fees:

Tier 1: $50

Tier 2: $50 plus $1 per kilowatt of rated generation output up to a maximum of $500

Tier 3: $100 plus $1 per kilowatt of rated generation output up to a maximum of $1000

Tier 4: $100 plus $2 per kilowatt of rated generation output up to a maximum of $1000

Study Deposits:

50% of estimated study fees

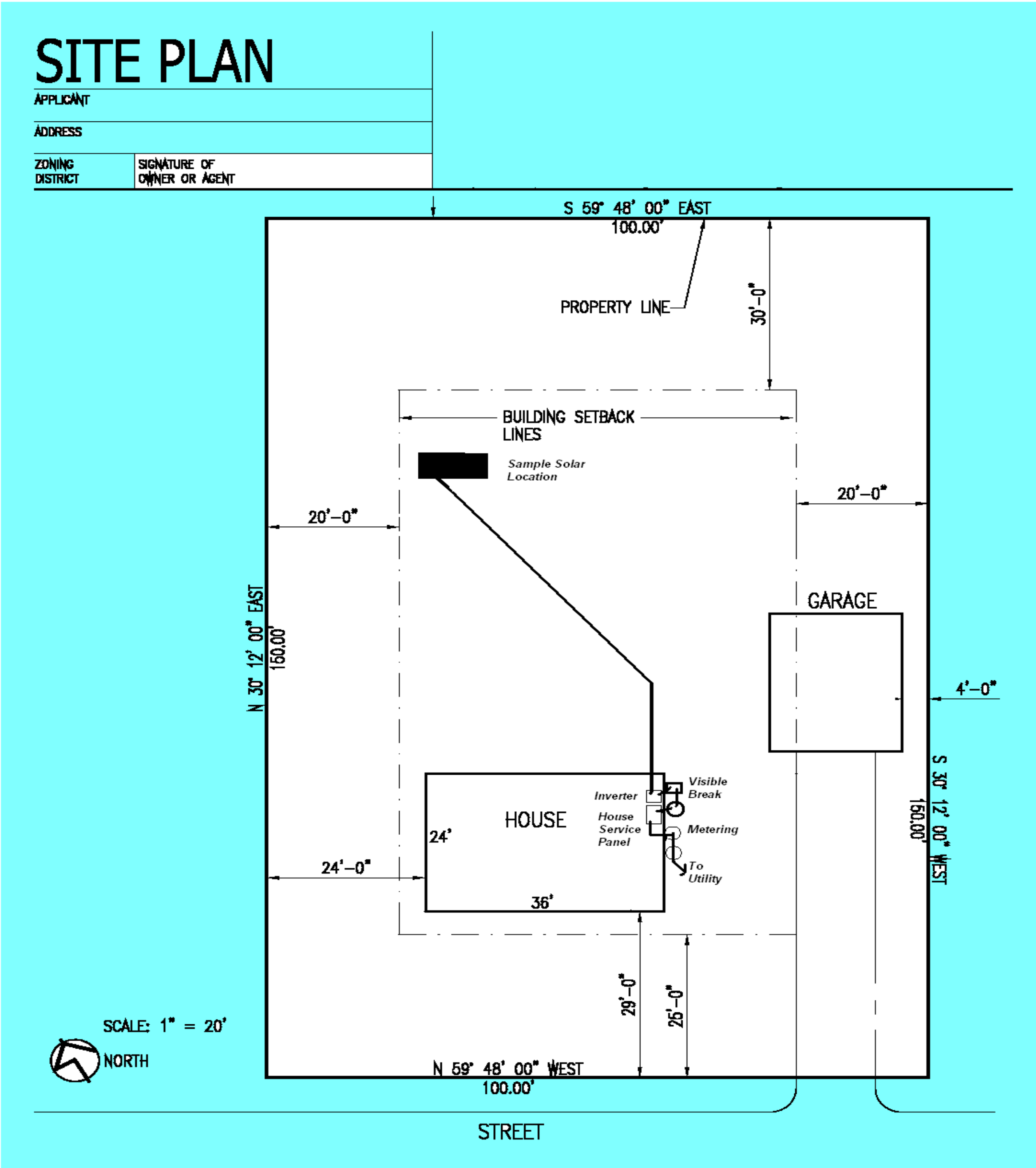
Deposit maximum $1000 for facilities rated 500 kW or less

Interconnection Facilities Deposit:

50% of estimated facility cost

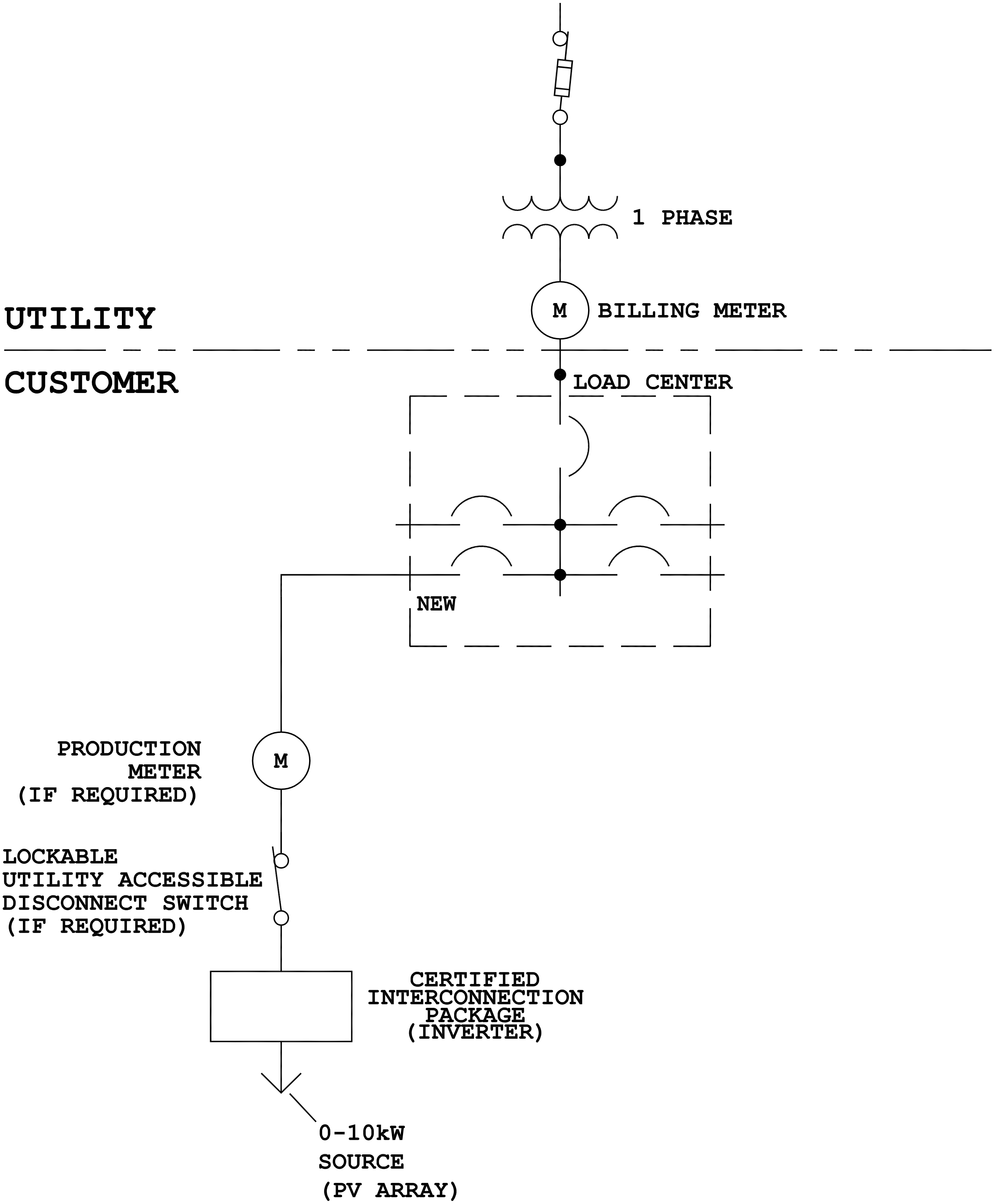
Deposit maximum $10,000 for facilities rated 500 kW or less

16.0 TYPICAL SMALL DG SITE-PLAN



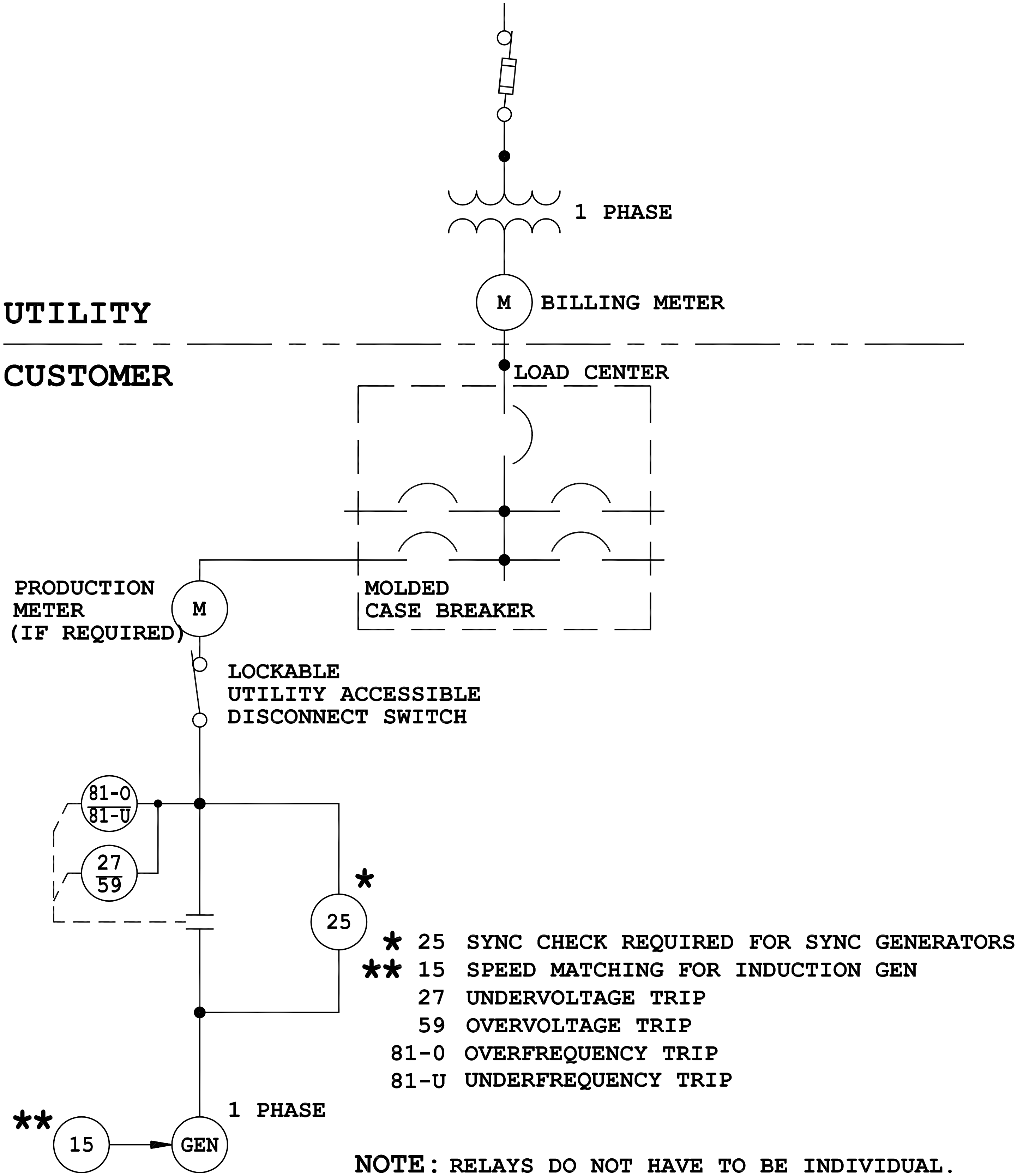
Note: Legible hand drawn site plans are acceptable

Typical One-line Diagrams



3/31/10

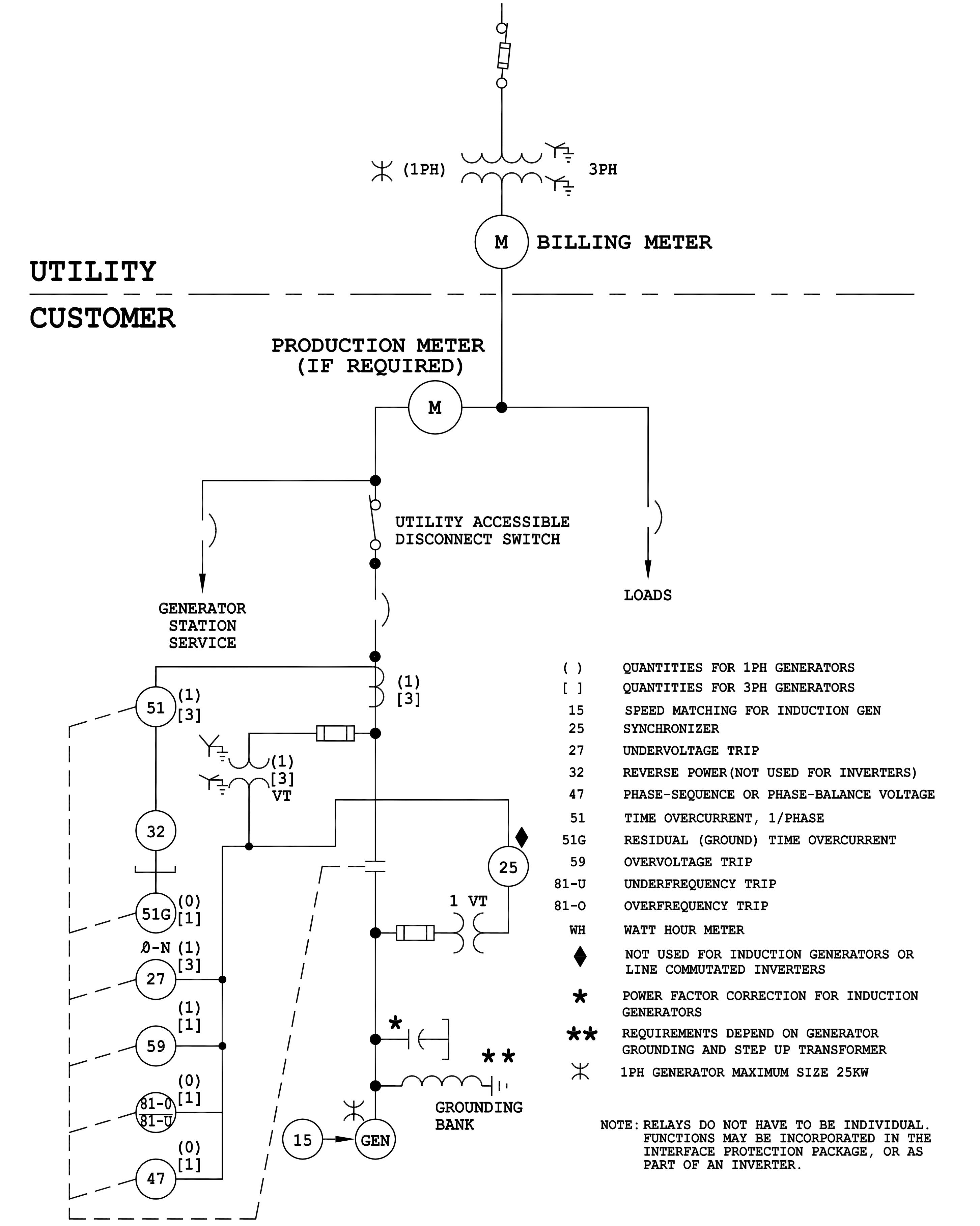
Xcel Energy	TYPICAL PARALLEL GENERATION CERTIFIED INSTALLATIONS LESS THAN 10kW, URBAN CONDITIONS	FIGURE NO. 10.1A



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

3/31/10

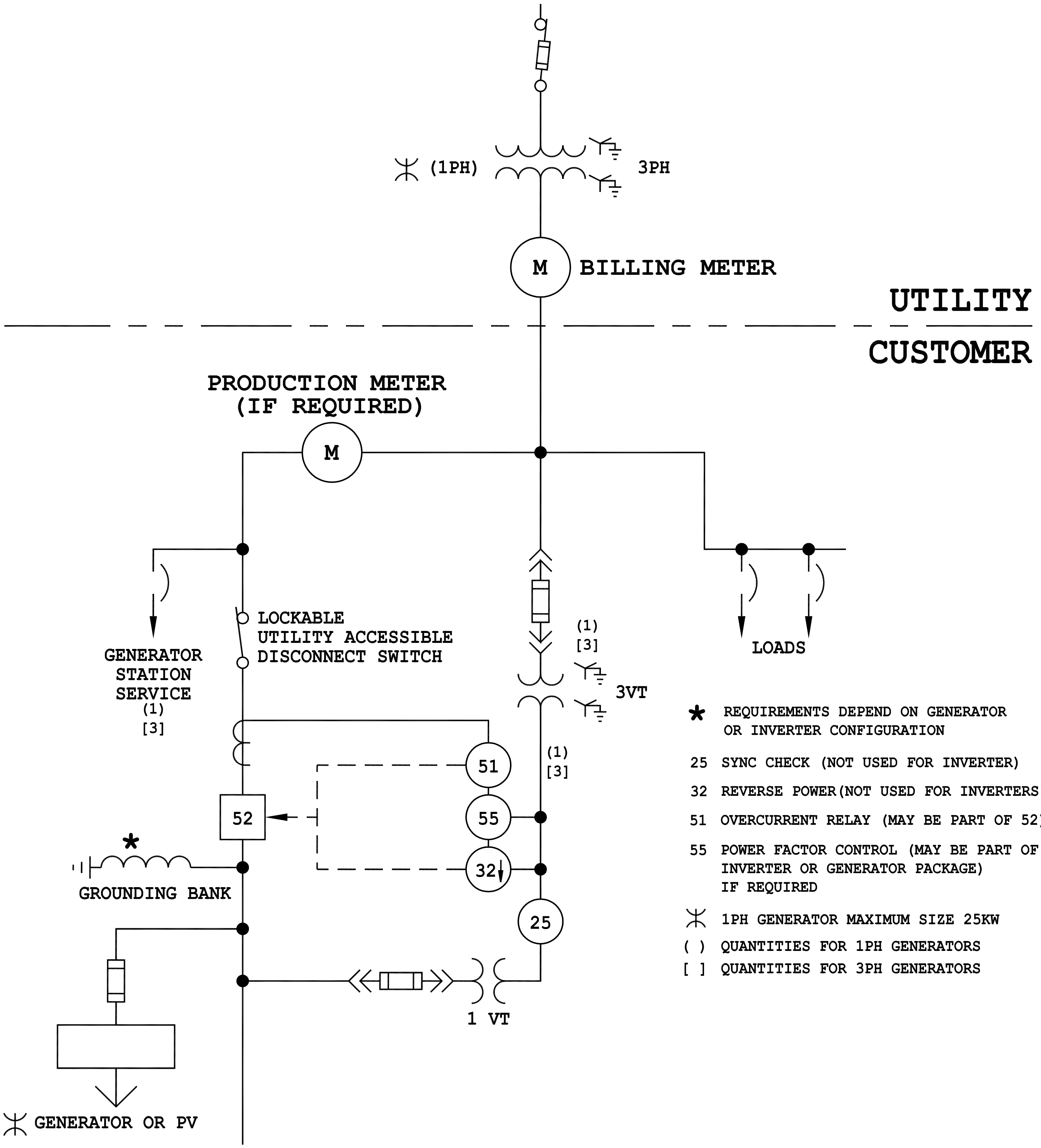
Xcel Energy	TYPICAL PARALLEL GENERATION NON-CERTIFIED INSTALLATIONS LESS THAN 10kW, URBAN CONDITIONS	FIGURE NO. 10.1B



UTILITY GRADE OR HIGH QUALITY INDUSTRIAL GRADE RELAYS

5/21/12

Xcel Energy	TYPICAL PARALLEL GENERATION INSTALLATIONS 10kW TO LESS THAN 100kW URBAN CONDITIONS	FIGURE NO. 10.2A



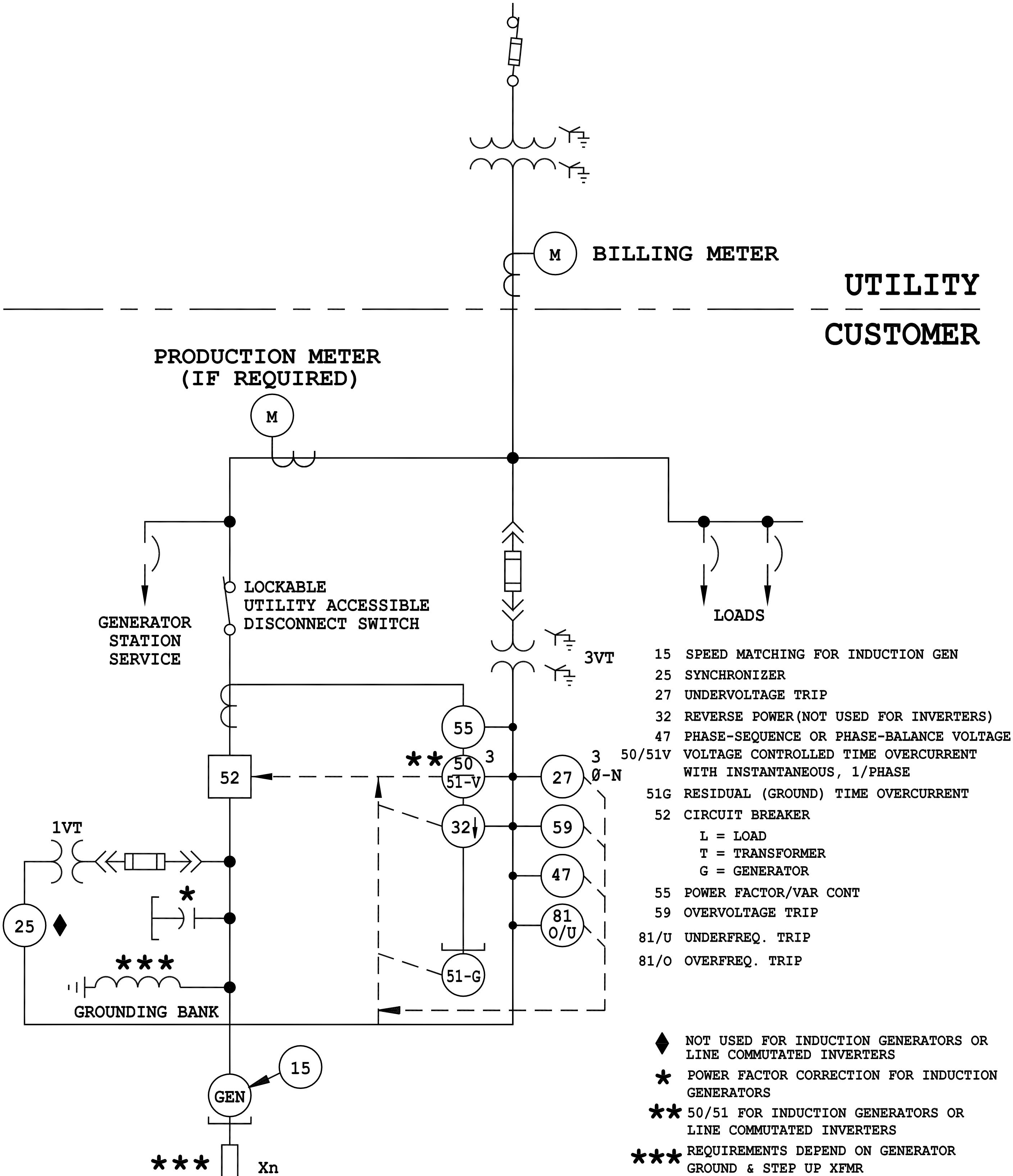
NOTE: RELAYS DO NOT HAVE TO BE INDIVIDUAL. FUNCTIONS MAY BE INCORPORATED IN THE INTERFACE PROTECTION PACKAGE, OR AS PART OF AN INVERTER.

5/21/12

Xcel Energy

TYPICAL PARALLEL CERTIFIED INSTALLATIONS 10KW TO LESS THAN 100KW URBAN CONDITIONS

FIGURE NO. 10.2B

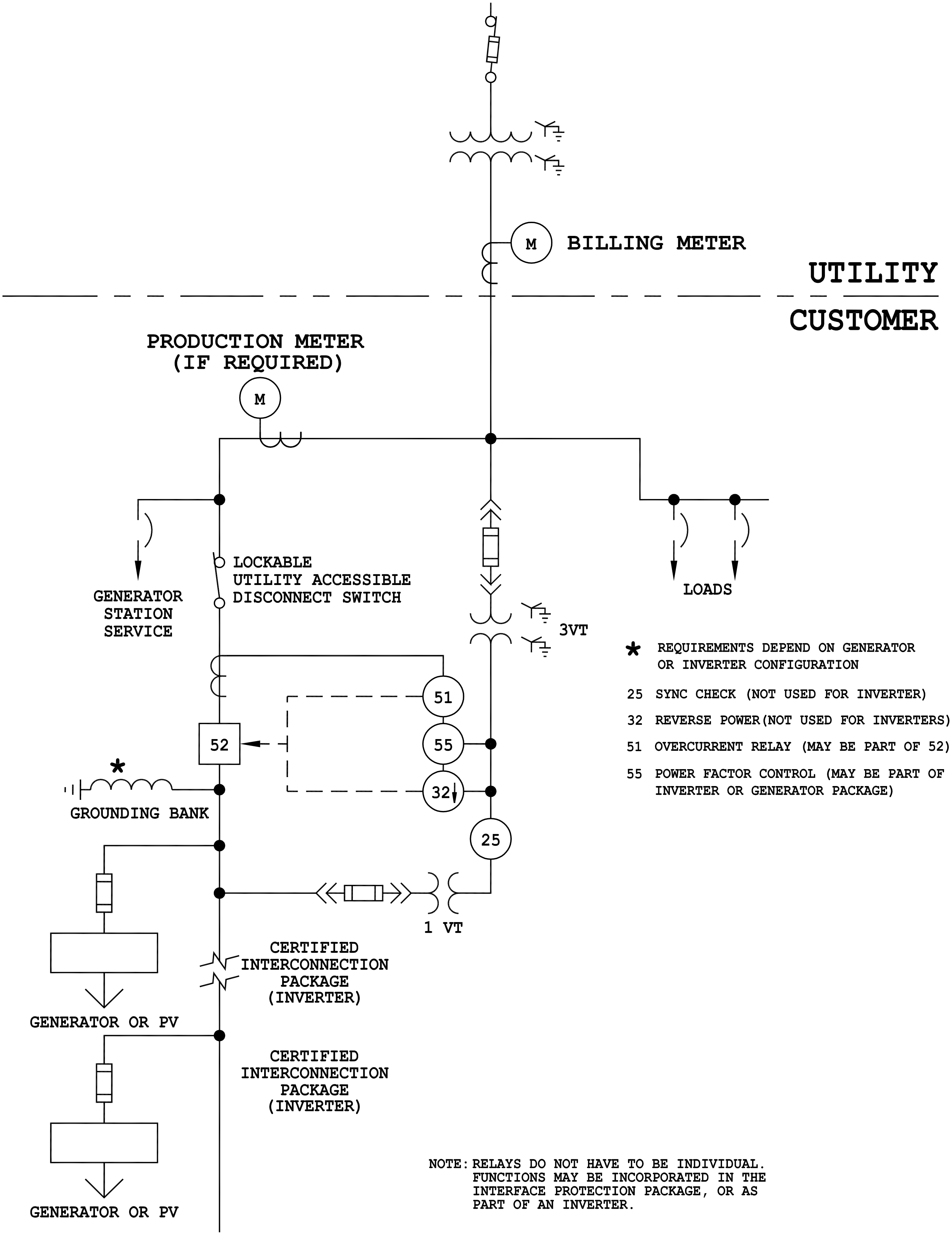


NOTE: RELAYS DO NOT HAVE TO BE INDIVIDUAL. FUNCTIONS MAY BE INCORPORATED IN THE INTERFACE PROTECTION PACKAGE, OR AS PART OF AN INVERTER.

UTILITY GRADE RELAYS

5/21/12

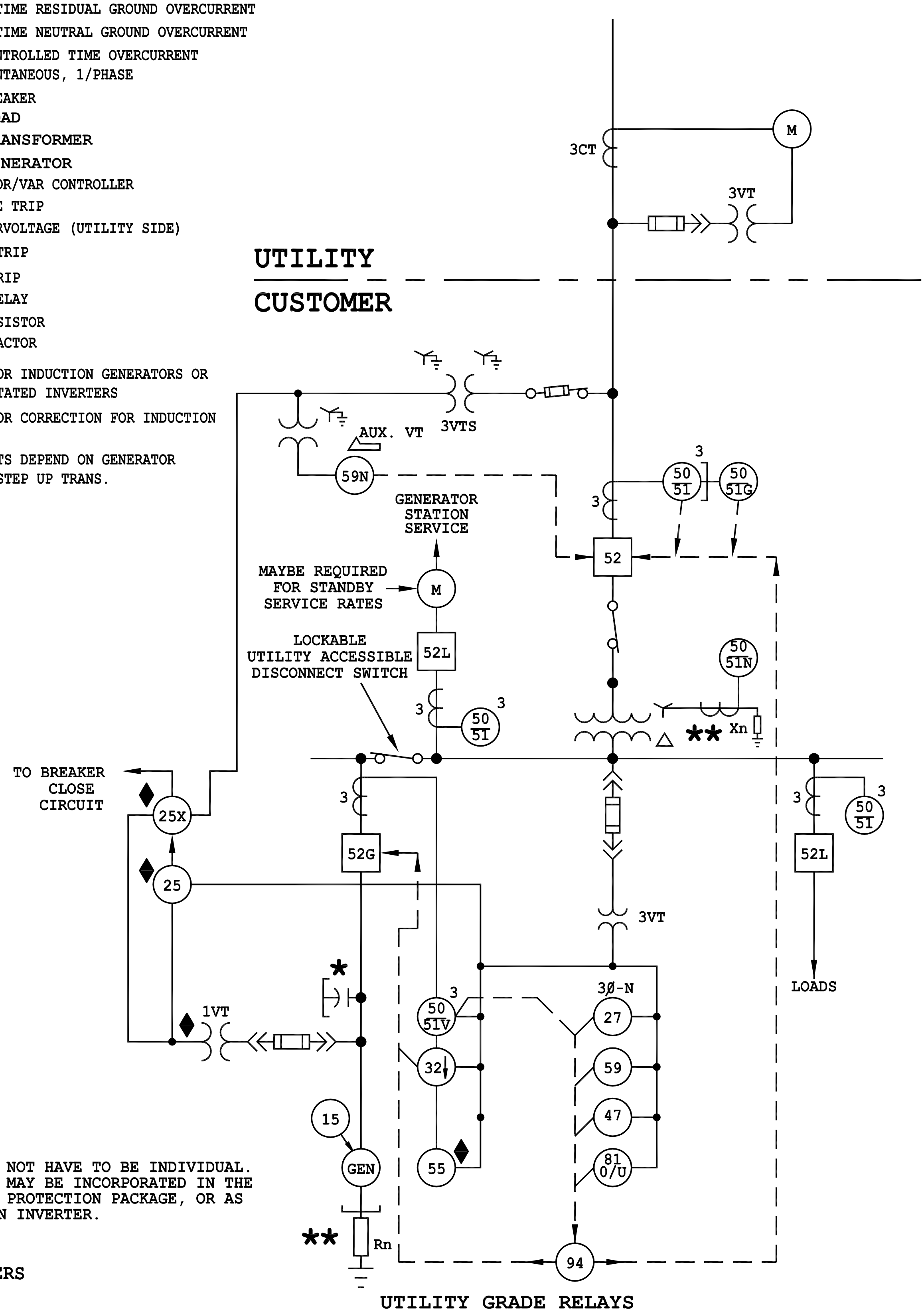
Xcel Energy℠	TYPICAL PARALLEL GENERATION INSTALLATIONS 100KW TO LESS THAN 1MW URBAN CONDITIONS	FIGURE NO. 10.3A



5/21/12

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.

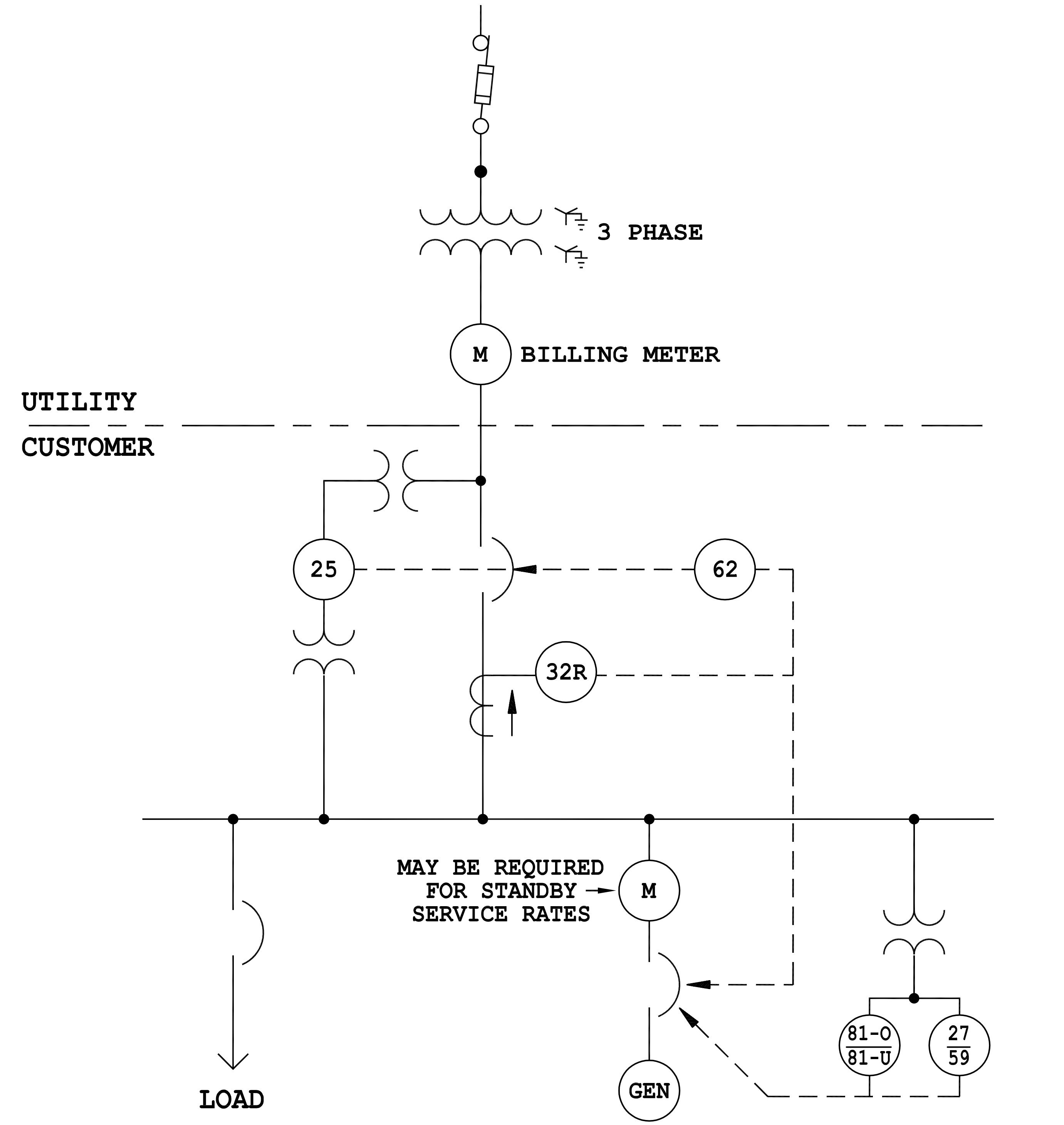
NOT SHOWN:
PRODUCTION METERS
TELEMETRY

5/21/12

Xcel Energy℠

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

FIGURE NO. 10.4



NOTE: EXCEPT DEVICE 62, 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	PARALLEL TIMER TRIP SEPARATE TIMER REQUIRED
81-U	UNDERFREQUENCY TRIP
81-O	OVERFREQUENCY TRIP

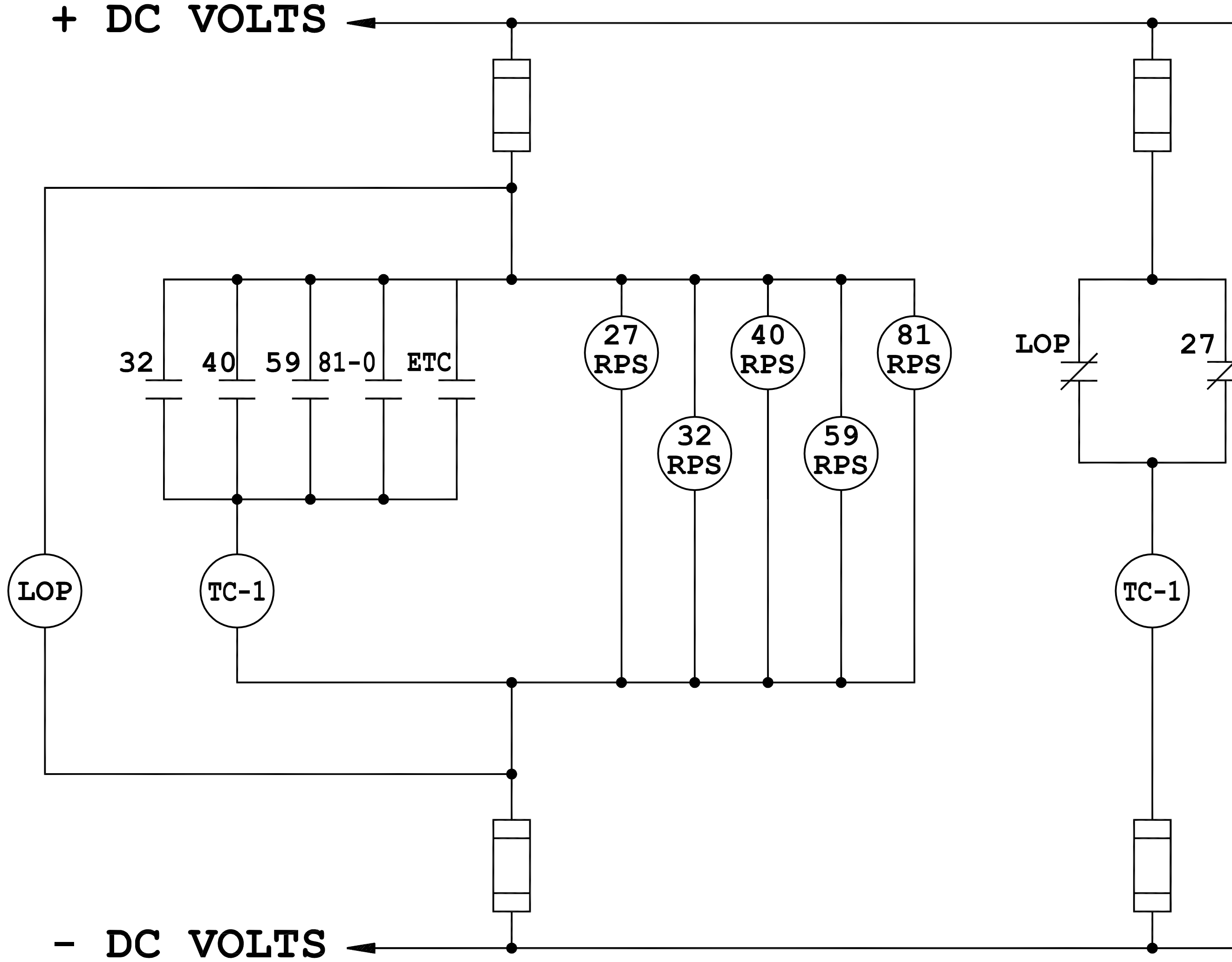
5/21/12

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

3/31/10

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