Xcel Energy®

NEW MEXICO

INTERCONNECTION REQUIREMENTS

FOR

DISTRIBUTION CONNECTED

SMALL GENERATION

SOUTHWESTERN PUBLIC SERVICE COMPANY

d/b/a

XCEL ENERGY

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SOUTHWESTERN PUBLIC SERVICE COMPANY
NEW MEXICO DG INTERCONNECTION REQUIREMENTS
TABLE OF CONTENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
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TABLE OF CONTENTS

NEW MEXICO INTERCONNECTION REQUIREMENTS FOR DISTRIBUTION CONNECTED SMALL GENERATION

1.0 INTRODUCTION

1.1 GENERAL

Process

The New Mexico Public Regulation Commission (PRC) Rule 17.9.568 (568) and the interconnection manual referenced in this rule set the process and timelines for interconnection applications, review, and approval. This document primarily addresses the technical requirements of interconnection but does provide some discussion, guidance, and additional information regarding the interconnection process. The New Mexico 568 Rules remain the final authority. As stated in the New Mexico 568 Rules and, by reference, the Interconnection Manual, the parties can agree to deviations, time extensions, etc. from those stated in the rules and Interconnection Manual. The rules provide for three levels of review complexity. The Interconnection Manual includes a flow chart of the technical screening process. Section 14 contains process flow charts to help the user understand the overall application and approval process of the three levels.

The three levels are:

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

<u>Fast Track</u> with or without Supplemental Review - For certified Generating Facilities that pass certain specified screens and likely would have a power rating of 2.0 megawatts (MW) or less,

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

Installations over 10 MW are covered by the rules found in NM 17.9.569:

Case Specific Review Process: For Generating Facilities with a Rated Capacity greater than 10 megawatts (MW), which shall be conducted pursuant to 17.9.569 (569) NMAC.

The NM 569 Rules derive from the original Public Utility Regulatory Policy Act (PURPA) interconnection rules. These rules are not as structured for time lines and specific review process steps. The 568 Full Interconnection Study Rules provide the basic structure and steps that are appropriate to use as a starting point for these over 10 MW installations. The 0-10 MW Application Form is a good starting point for the application process. The Full process is similar to the FERC SGIP (Federal Energy Regulatory Commission Small Generator Interconnection Process). The FERC SGIP is a suitable alternative process for the larger units. The Company and the Customer should mutually agree upon the process during the application phase of the project.

New Mexico Rule 17.9.570

New Mexico Rule 17.9.570 (570) is to govern the purchase of power from and sale of power to qualifying facilities. These rules address operational, metering, and rates aspects of interconnections. These rules:

- Define the utility's obligation to purchase power
- Presents the metering options available to various Customers

- Establish methodology for the determination of rates for purchases
- Defines the Customer's obligation to sell power
- Define when purchases and sales are not required
- Provides general provision that apply to interconnection
- Presents the methodology for doing net metering for 10 kW or less
- Provides the standard metering and billing agreement for qualifying facilities greater than 10 kW to 10 MW

Definitions

Several of the terms used in this document and the State PRC Rules are defined in the Definitions Section 11. These terms are intended to carry the same meaning as used in the New Mexico PRC 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. The New Mexico 568 rules and the referenced Interconnection Manual are provided in Section 13.

Technical Standards

The PRC 568 Rules require the use of IEEE 1547 and 1547.1 for the technical requirements, interconnection equipment certification, and commissioning testing. This document is intended to provide discussion, summarization, and clarification of these standards for use under the NM 568 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 NM 568 Rules do not address telemetry, metering, and other details necessary to interconnect successfully. This document will provide additional guidance and details for these aspects. Additional references that may be of use are listed in Section 12.

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 the same as the New Mexico Public Regulatory Commission (PRC) 17.9.568 term "Interconnection Customer." The term "Company" will be used to refer to Southwestern Public Service Company, 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 guidelines. The minimum requirements for distribution interconnected generation to safely and reliably interconnect to the Company power grid are stated in this document. These requirements are meant to *protect the Company and its other customers*. The Customer is responsible for the overall safe and effective operation of *their* generating facility. The Customer is responsible for designing their own protection scheme and should consult an expert in the field of system protection for distributed generation. The typical relaying one-line diagrams contained in this document illustrate interconnection relaying to protect the Company only.

Screening Philosophy and Small Unit Compliance

The NM 568 Rules and FERC SGIP 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 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 as IEEE 1547, refined national codes, such as NEC, and type tested interconnection products, such as certified inverters, make this a safe and expedited practice.

<u>*Most small installations are relatively standardized, will pass the Simplified screens, and will comply with the balance of this document. The statements most relevant to these small installations are underlined.*</u>

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

Units that pass the screens for the Fast review will likely comply with the technical aspects of this document. Most large units will not pass the screens. The primary use of this document is for addressing the requirements and needs of these unique applications that require the Full 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, the NM 568 Rules, and the Interconnection Manual. 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. The parties may *mutually agree* to other requirements than are contained in IEEE 1547 or this document.

FERC Jurisdictional Units

Some distribution connected generation units may be classified as FERC jurisdictional units. These facilities must apply, be reviewed, and be approved according to the FERC Small Generator Interconnection Process (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 New Mexico Rules.

1.2 POLICY ON INDEPENDENT GENERATION

The Company will allow any Customer, as permitted under New Mexico 568 and 569 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 affects 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 NM 568 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.

1.3 GENERATION SOURCES

The New Mexico 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 NM 568 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 usually have less stringent requirements. Each paralleling mode of operation requires 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 power 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 1.6).

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). 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 amount 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 LIABILITY

The following language is from the New Mexico Interconnection Manual's Interconnection Agreement for large generation facilities, Exhibit 3B. Simpler language is applied to <= 10 kW inverter based facilities, Exhibit 3A.

"The Interconnection Customer shall indemnify and hold harmless the Utility against all damages, expenses and other obligations to third parties attributable to the negligence, strict liability or intentional acts of the Interconnection Customer. The Utility shall indemnify and hold harmless the Interconnection Customer against all damages, expenses, and other obligations to third parties attributable to the negligence, strict liability, or intentional acts of the Utility. The terms "Utility" and "Interconnection Customer," for purposes of this indemnification provision, include their officers, directors, trustees, managers, members, employees, representatives, affiliates, successors and assigns.

Except in the event of acts of willful misconduct, each Party's liability to the other Party for failure to perform its obligations under this Agreement shall be limited to the amount of direct damage actually incurred. Neither Party shall be liable to the other Party for any punitive, incidental, indirect, special, or consequential damages of any kind whatsoever, including for loss of business opportunity or profits, regardless of whether such damages were foreseen.

Notwithstanding any other provision in this Agreement, with respect to Utility's provision of electric service to any customer including the Interconnection Customer, the Utility's liability to such customer shall be limited as set forth in the Utility's tariffs and terms and conditions for electric service, and shall not be affected by the terms of this Agreement."

2.0 COMPANY SYSTEM INFORMATION

2.1 VOLTAGE

The Company's most common primary distribution voltages are 12.5 kV, 13.2 kV, 25 kV, and 34.5 kV depending on the geographic area; other voltages are sometimes used in specific areas. The majority of the distribution circuits are "effectively grounded" (see Section 2.3) and are used for 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.

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 circuits are set to reclose with no intentional delay. When a reclosing delay is used, the delay is typically 2 seconds or less. Upon request, the Company will consider increasing the existing feeder reclose delay. A number of substations are tapped to the transmission lines and are subject to transmission line reclosing. Most transmission reclosing has no intentional delay. When delay is used, it is commonly 2 seconds or less. 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; however, the anti-islanding protection usually cannot disconnect the facility before a zero delay reclose occurs. Sometimes, especially for larger units, the Customer's interconnection relaying is not adequate or quick enough to ensure generator separation before a Company delayed reclose. *An out-of-synchronism reclose may result in damage to load or generation equipment and, for 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 certified 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 NERC limits (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.

Should a *Customer* desire additional protection against the possibility that reclosing might occur with the Customer's generator still connected to the line, the Company may be able to provide "Hot Line Reclose Blocking" (HLRB) or sync-check supervision at the reclosing point on its system. HLRB 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 and the Customer is responsible for the expense of the Company installing, maintaining, and/or rearranging any of its equipment for 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.

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. <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. To achieve effective grounding, a Customer's system equivalent (Thevenin equivalent impedance) must meet the following two criteria (IEEE Std 142-1982):

a) The positive sequence reactance is greater than the zero sequence resistance (X1 > Ro).

b) The zero sequence reactance is less than or equal to three times the positive sequence reactance. *It is desirable for the ratio to be between 2.5 and 3.0 (2.5*X1 ≤ Xo ≤ 3*X1) to limit the adverse impacts on feeder 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 Xd" 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. Wye-wye transforms 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 requires 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. A grounding reactor is not recommended since significant generator derating due to unbalanced currents may result.

e) Voltage imbalance on the Company's distribution system may result in substantial current flowing into a Customer's generator(s) or grounding equipment. The Company's operating objective is to keep phase-to-phase imbalance under 1% and phase-to-ground imbalance under 3%. 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.

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. 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.

f) The generator reactance used in calculating the ratio Xo/X1 should be the subtransient direct axis reactance (Xd").

Inverters, Double-fed Induction Generators, and Others

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

Inverter installations that are large in single unit or composite facilities should be checked for effective grounding equivalency. <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 neutral shift during a single line-to-ground fault must be constrained to avoid an overvoltage condition to the single-phase loads connected the unfaulted phases.

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 does not ensure a grounded wye configuration. Three-phase inverters normally use an internal transformer between the AC output and the inverter circuits to provide isolation and voltage matching. Either a delta-wye-grounded or a wye-wye-ground configuration will usually provide adequate ground referencing. If the inverter does not meet the effective grounding criteria, either a small grounding bank will be needed or grounding with a wye-delta-grounded with neutral reactor step-up transformer, see Figure 10.4, will be needed.

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

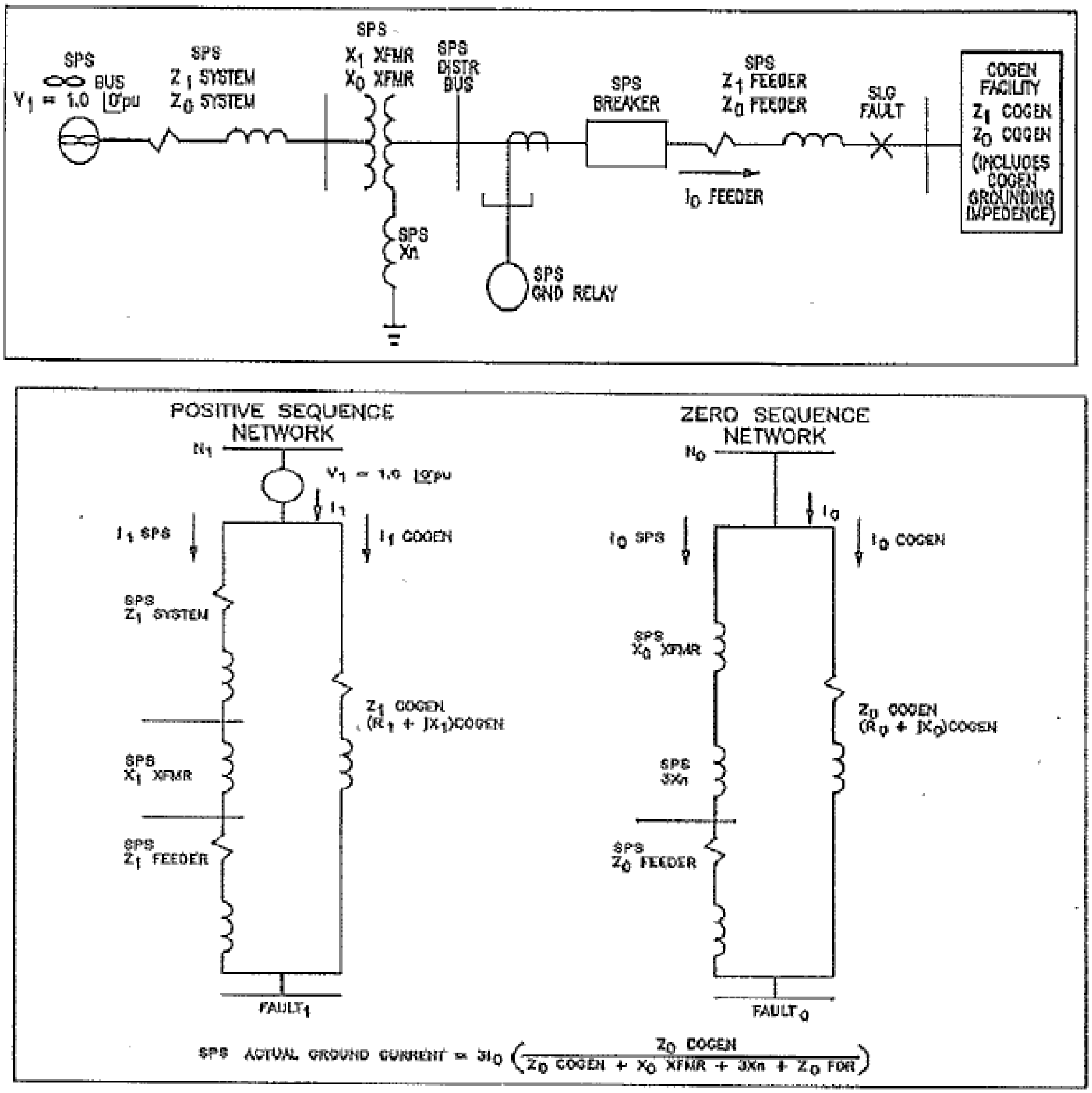
Generation technologies other than those discussed above may come into use. The same principles will apply to them. The energy source delivered into an effectively grounded distribution system must provide effective ground referencing during islanding.

Company Ground Relays

The Company's ground relays located at our substation and on our 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 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. 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 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.

The following diagrams summarize the effective grounding methodology:



Xcel Energy GROUND RELAY CURRENT CALCULATIONS
Figure 2.3.1

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 kW load that will be on the generator during the islanding condition will at all times be at least two 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 Simplified Interconnection or Fast Track interconnection as discussed in the Interconnection Manual will qualify for the ungrounded operation option.</u>

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>Certified inverters, unless they are malfunctioning or misapplied, will comply with the Section 3 requirements.</u> Abnormal voltages, frequencies, harmonics, or interruptions must be kept within limits specified under IEEE 1547 and IEEE 519. If high or low voltage complaints, transient voltage complaints, and/or harmonic (voltage distortion) complaints result from operation of a Customer's generation, such generating equipment shall be disconnected from the Company's system, as permitted under NM 568 Rules, 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.

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 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 or VAR 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.

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 a value in the 0.95 leading to unity power factor range. 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 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 and 519. 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.

<u>Small generation units usually can 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 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 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 state’s Public Regulation 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 Southwest Power Pool.

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 this is usually not considered FERC jurisdictional, the transmission provider may place operating restrictions on the generation unit(s), such as curtailment during certain system contingencies, or require the generation facilities to pay for modifications to the transmission system, such as the use of transfer trip. The Company Engineer will work with the 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 (see Section 5.11). This requirement may restrict the settings available for the anti-islanding underfrequency relaying.

The 2008 National Electric Code, NFPA 70, contains an article that restricts the size of inverter based interconnection into a shared panelboard. Article 705.12(D)(2) states for inverter interconnections: The sum of the ampere ratings of overcurrent devices in circuits supplying power to a busbar or conductor shall not exceed 120 percent of the rating of the busbar or conductor. For a typical 200A residential panel, this means 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.

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 NM 568 Rules and Interconnection Manual. The complexity of the protective devices differs with the size of the installation (see Section 5 and Section 10 one-lines).

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 for line clearances, must be provided. The form of this device will vary with the service voltage and generator capacity. <u>The NM 568 Rules allow omitting of this disconnection device for units rated 10 kW or less that are interconnected with a certified inverter *and* have a separate power production meter, see rule 17.9.568.15.B for details.</u>

4.3 QUALIFIED PERSONNEL

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

4.4 DESIGN REVIEW AND DOCUMENTATION

The Customer, in accordance with the NM 568 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 specific design documents and test procedures will vary depending for each facility; however, some general documents for the design review process are outlined below as a guide to the Customer. The information is tailored to medium to large installations. <u>For small installations, especially those using certified interconnection equipment, the documentation needs are minimal.</u>

a) The Customer submits an application as specified in the NM 568 Rules. The Company performs a review and approves the design according to the process specified in the NM 568 Rules for the size, type, and location of the generation package. A site-plan diagram is suggested (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 (voltage and physical location). 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 568 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 also 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 certified interconnection equipment, the Company requests certified test reports for the interconnection facility protective relaying and any equipment directly connected to the Company's system (such as Customer's transformers and/or breakers). Company may witness the tests, calibrations, and relay setting applications. The Company 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 certified to comply with IEEE 1547.1 by a national 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 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). For larger facilities, the individual inverters must have a TDD or 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 New Mexico 568 Rules directly address classes 1 - 4. NM 569 Rules address class 5. These classes are:

1. 10 kW and under (small)
2. Over 10 kW to 100 kW (system dependent)
3. 100 kW to 1 MW (medium)
4. 1 MW to 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.

The relays indicated in Figures 10.1 through 10.4 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 certified interconnection packages up to 30 kW do not require relay setting determination.</u>

For most installations, utility grade relays are required. Certified interconnection packages are accepted as complying with these criteria. 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.).

5.2 INSTALLATIONS 10 KW AND UNDER

Except for certified interconnection packages, all installations in this class will require a design and relay review by the Company (i.e., metering and relaying one-lines, protection and control schematics, relay setting sheets, and nameplate data of the generator(s), breaker(s), and disconnect switch(es)). 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 certified protection package. Each package will be reviewed to verify that is certified and applied in a manner consistent with its certification.</u>

The protective relaying details are shown in Figure 10.1. <u>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, except as exempted under the NM 568 Rules, 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 note should be provided at the metering or PCC location indicating the location of the switch.</u>

5.3 INSTALLATIONS FROM 10 KW TO 100 KW

Except for certified interconnection packages, all installations in this class will require a design and relay review by the Company (i.e., metering and relaying one-lines, protection and control schematics, relay setting sheets, nameplate data of the generator(s), breaker(s), disconnect switch(es), and certified test reports). The Company will determine if a relay and site inspection (i.e., witnessing the calibration and testing of the relays and operation of the generator and breakers, see Section 7) is required. Installations using certified interconnection packages do not require the full documentation; however, review of relay settings for units over 30 kW is needed.

Those installations that use a certified package will be given a quick review. All installations that are not a standard package must be reviewed individually. These installations may vary somewhat from the layout shown in Figure 10.2. 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) is also required. The documentation and review can be reduced if certified interconnection packages are used. For this size range, the proposed relay settings must be provided for certified packages.

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

The intent of the protective relaying requirements is given in Figure 10.3. 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 certified interconnection packages. This is a common practice with photovoltaic sites. The certification process certifies the design and functionality for only the package with its associated energy source. It does not address the increased system impacts that multiple units will have. Because of this, a site with multiple packages must be reviewed and additional protective equipment and field-testing 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 is 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 are covered by the NM 17.9.569 Rules. Installations over 10 MW are usually 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 installations are usually subject to standby tariffs. 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. 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.

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 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 OVER/UNDER FREQUENCY COORDINATION WITH NERC STANDARDS

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 Southwest Power Pool's (SPP) 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 shedding step is 58.7 Hz.

The requirements are under review and may change. One proposal is to require generation units to remain on-line above 58.2 Hz, remain on-line at 58.2 Hz for 4 minutes, and trip with no delay at or below 57 Hz. 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 islanding protection, the highest frequency, and shortest time delay settings consistent with the above requirements is recommended. Symmetrical overfrequency and times are suggested.

5.12 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 certified for use with synchronous generators will include this functionality.</u>

Sync-check relays (device 25 or 25X per Figures 10.1-10.4) should be included in addition to the synchronizing relays on large synchronous generators. The 25X function should be a separate device (i.e., not included in the synchronizer) for all units 1 MW and above. The 25X, 25 relay, and any other sync relaying, must not allow the Customer's facility to energize a de-energized Company line. 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 is held within the tolerances described in Section 3.2 and 3.3. Double-fed induction generators usually 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 $\underline{+}$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 drop associated with the magnetizing inrush current.

5.13 GOVERNOR DROOP REQUIREMENTS

All 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.

5.14 DC FUSING

Larger units must have some form of interconnection facility protection redundancy to insure that a single failure does not disable all interconnection 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 10.5 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 highly recommended.

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 Company's Guide Book for Electric Installation and Use (Guidebook). The metering voltage will usually be the same voltage as the point of delivery.

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 the primary meter rate. In some cases, the Company may agree to meter on the low-side, or customer-side of the transformer to save costs. 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 RULES

The NM 17.9.570 (570) Rules govern the purchase of power from and sale of power to qualifying facilities. The 570 Rules govern both power purchases with buy-sell metering arrangements and with net metering arrangements. Net metering is available under several arrangements. The Customer should consult the Company tariffs, as approved by the NM PRC, to determine the details, conditions, and rates available for their situation.

This metering is referred to as revenue metering. Various renewable generation units are eligible to receive payment for production credits, also know as renewable energy credits (RECs). Renewable generation installations usually require the installation of a separate REC production meter, in addition to the Customer’s revenue meter, to measure the power produced by the generation unit.

The NM 570 Rules also specify the requirements, conditions, and cost methodology for the Company to provide maintenance power and standby rates to the Customer. The Customer should consult the Company tariffs, as approved by the PRC, 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 570 Rules detail these conditions.

The 570 Rules specify the cost responsibilities for the additional costs incurred to meter the Customer’s generation, provide net metering where applicable, provide production metering where applicable, and perform meter reading and processing. For most situations, these added costs are the responsibility of the Customer. The Customer should consult the Company tariffs, as approved by the PRC, to determine the details, conditions, and rates that apply to their situation.

6.3 METERING CONFIGURATIONS

10 kW and Less Net Metering

Most residential customers pay a bundled flat rate for their power. The rate is composed of the measured energy used and a fixed fee for meter reading and processing. New Mexico rules allow net metering of the energy portion of the bill for 10 kW and less qualifying facilities, see Rule 570.14. In most cases, either the existing meter or a new meter placed in the same meter socket is used to perform the net metering.

Certain facilities also qualify for REC payments. To receive a REC payment, a separate production meter must be installed. The Customer should consult the Company tariffs, as approved by the PRC, to determine what rebate and REC payment programs are available for their situation.

Other Metering Options

The New Mexico 570.10 Rules allow “load displacement metering”. The Customer provides some of their own power with their generation. In these cases, the existing metering is set to register only delivered power and will not record received power. Standby or maintenance rates may apply.

"Time of use metering" is used for larger customers. These rates are composed of a demand charge, an energy charge, and fixed fee for meter reading and processing. The net metering rate allows the Customer to net only the energy component of the rate. Existing metering usually must be replaced to be able to record both delivered and received energy. Certain facilities also qualify for REC payments. To receive a REC payment, a separate production meter must be installed. The Customer should consult the Company tariffs, as approved by the PRC, to determine what rebate and REC payment programs are available for their situation.

"Separate load metering," with generation metering separate from the load metering, is available. This arrangement is also called simultaneous buy-sell. The Customer's generation is delivered to the Company system through its own meter. This meter is installed before the generation is connected. A meter, with separate registers for in and out, is usually installed to separately account for generation and for consumption when the unit is off-line. Power is delivered to the load by the Company to the Customer through the existing metering. Certain facilities also qualify for REC payments. The generator's revenue meter may be suitable for REC monitoring also. The Customer should consult the Company tariffs, as approved by the PRC, to determine the details, conditions, rates, and REC payment programs available for 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, certified protective packages.</u> Some additional demonstration for larger certified 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 NM 568 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 is to be determined by the Company's engineers.

The commissioning testing and demonstration shall be conducted in accordance with the requirements of IEEE 1547.1, as specified in the NM 658 Rules. 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 test can be skipped for medium to small facilities. <u>Facilities using certified 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 operate 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 permanent interconnection with the Company's system.

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 responsibility 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

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

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.

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

- 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 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 certified interconnection equipment. The procedures do not need to be this complete when certified equipment is used. Small facilities with certified 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, 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).

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 less than 10 MW rated 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 should 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 other 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 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/operating procedures.

d) For all units with an active governor, a droop setting on the governor of 5% (see Section 5.13). Governor dead-bands: NERC Policy 1 states, "Governors should, as a minimum, be fully responsive to frequency deviations exceeding +/- 0.036 Hz (+/-36 mHz)."

e)

8.4 TELEMETRY

1 MW and Greater

a) Customer facilities 1 MW and greater will require that SCADA be provided as part of the required system modifications.
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, more stringent monitoring and control will be needed.
c) Additional information may be required, either initially or later, such as ambient, wind speed, or solar intensity.
d) The Company must have the ability to remotely disconnect or curtail the generation for larger installations. This control is needed to quickly address transmission constraints and contingency conditions, as required by NERC reliability standards, that 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.

500 kW to 1 MW

a) The Company may require the ability to remotely monitor the status and output of intermediate size installations. This information is needed to quickly address transmission constraints and contingency conditions, as required by NERC reliability standards, that must be addressed quickly.
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, more stringent monitoring will be needed.
c) The Customer is expected to provide suitable space for the installation of the monitoring and telemetry equipment.

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 NM 568 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.

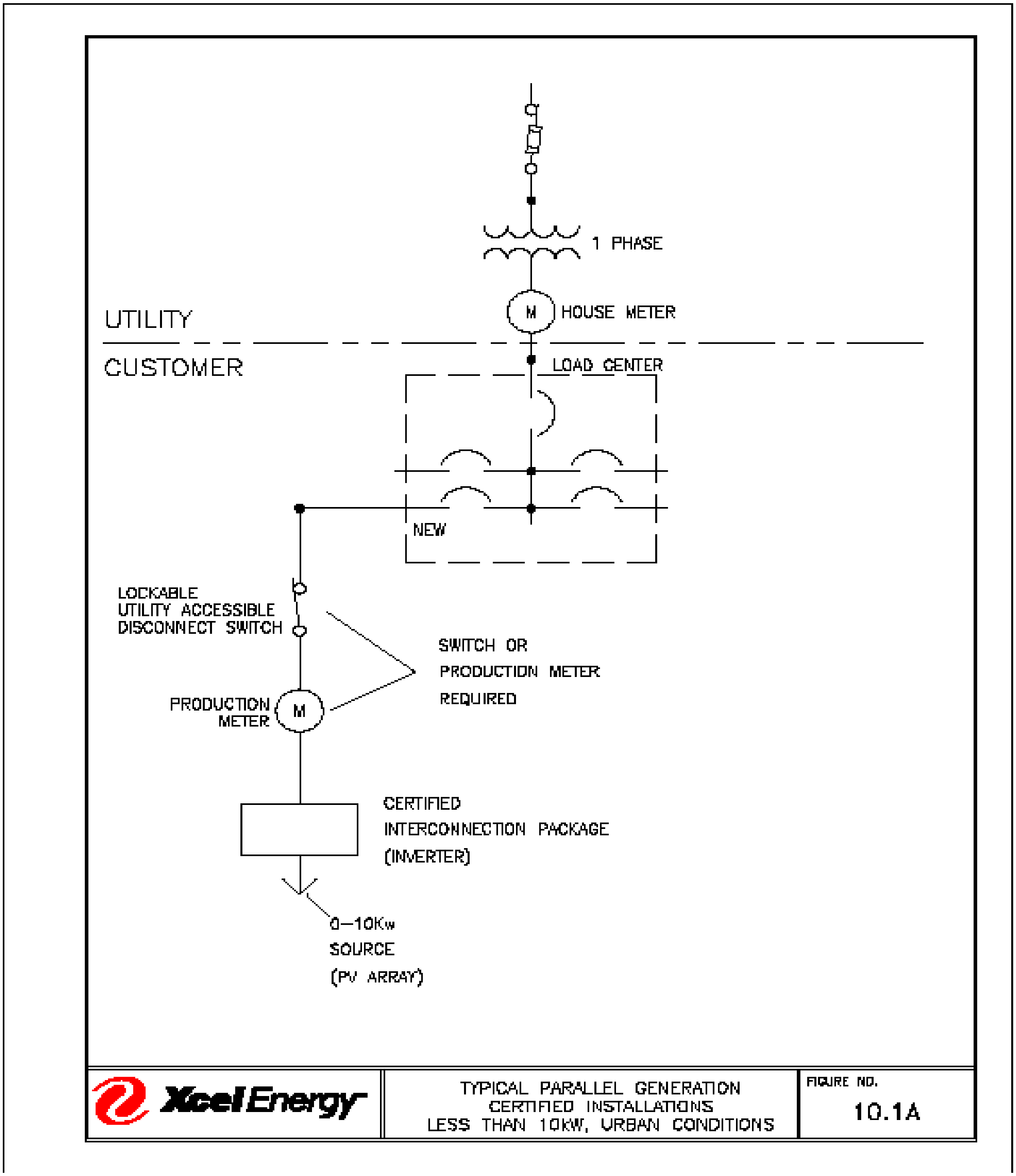
9.2 DESIGN CHANGES AFTER COMMERCIAL OPERATION

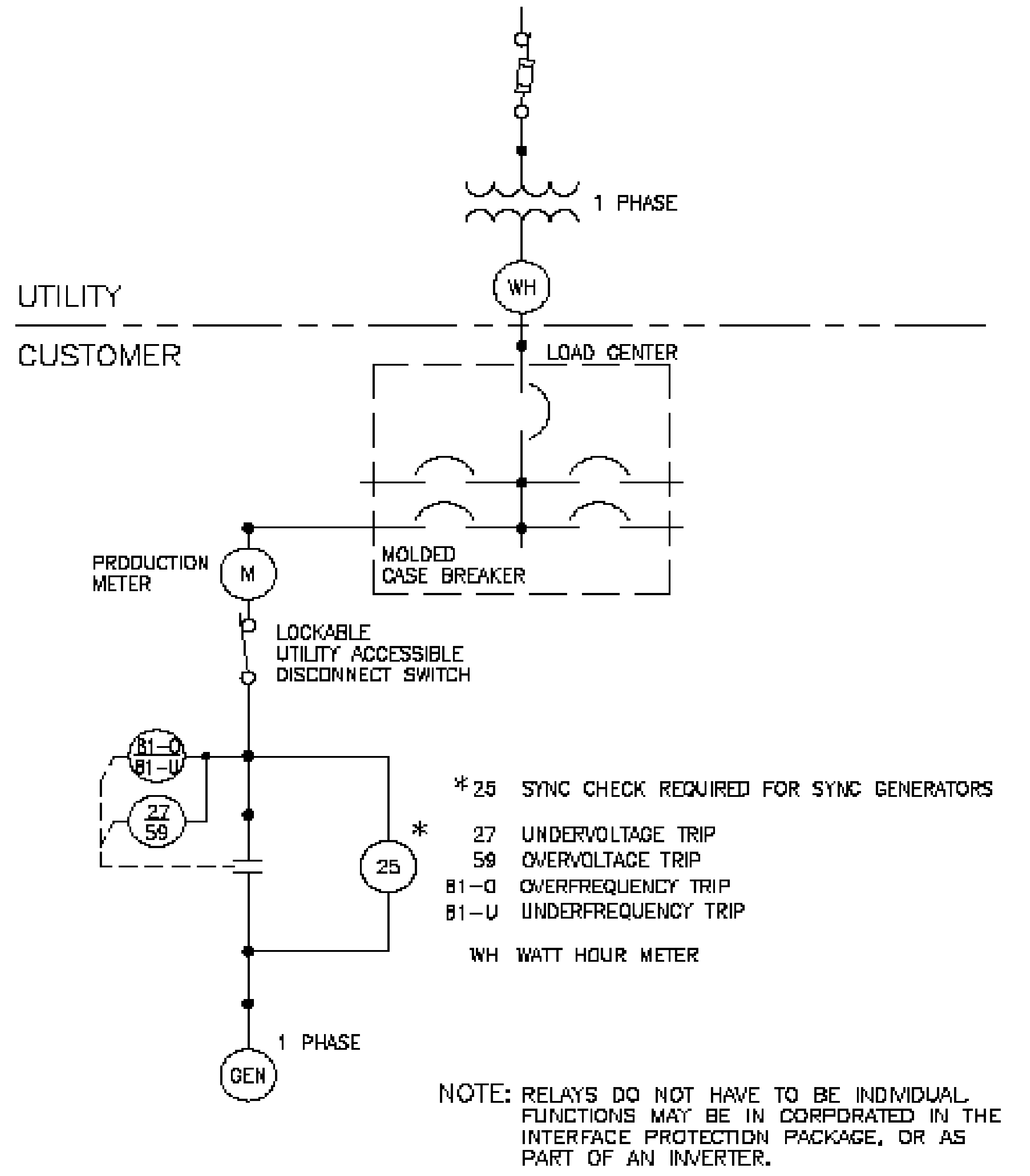
Any modifications to the interconnection facility after the date of commercial operation that alters the unit size, configuration, or other substantial aspects will need to be reviewed by the Company. Suitable commissioning testing will be required. Replacement of certified interconnection packages of like rating generally does not constitute a modification assuming packages over 30 kW use the same settings.

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

10.0 TYPICAL RELAYING ONE-LINE DIAGRAMS

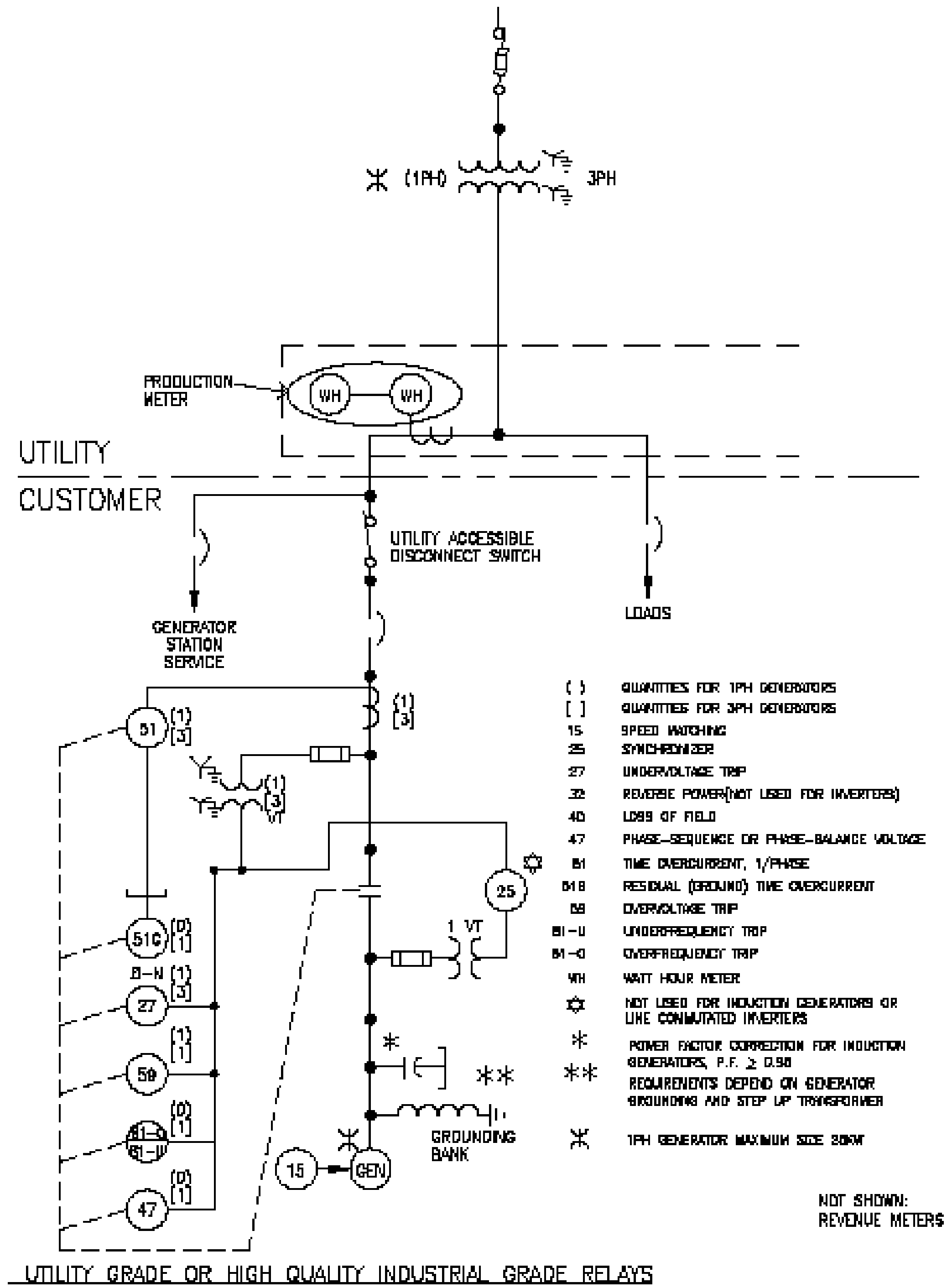
10.1 0-10 KW





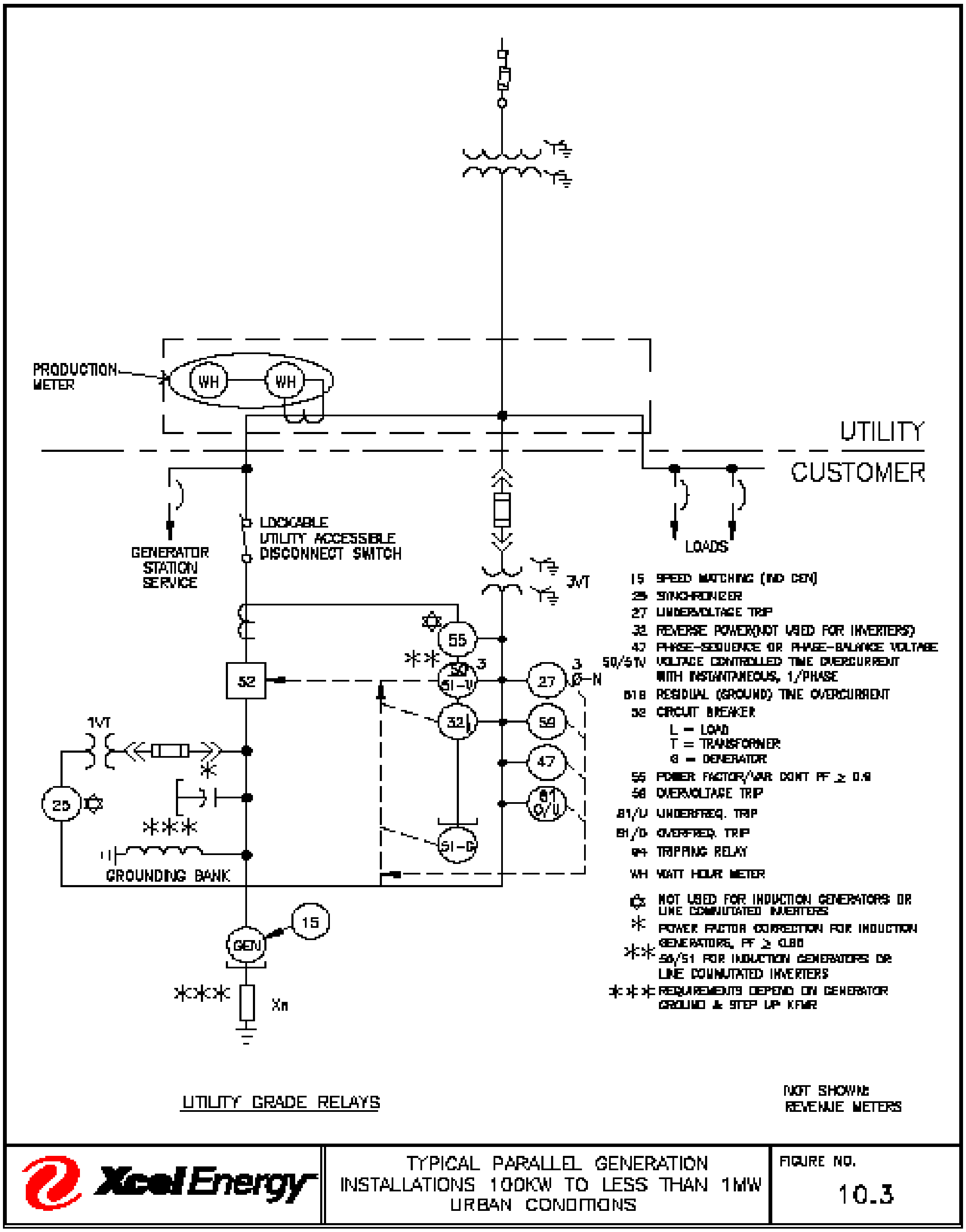
Xcel Energy	TYPICAL PARALLEL GENERATION NON-CERTIFIED INSTALLATIONS LESS THAN 10KW, URBAN CONDITIONS	FIGURE NO. 10.1B

10.2 10-100 kW

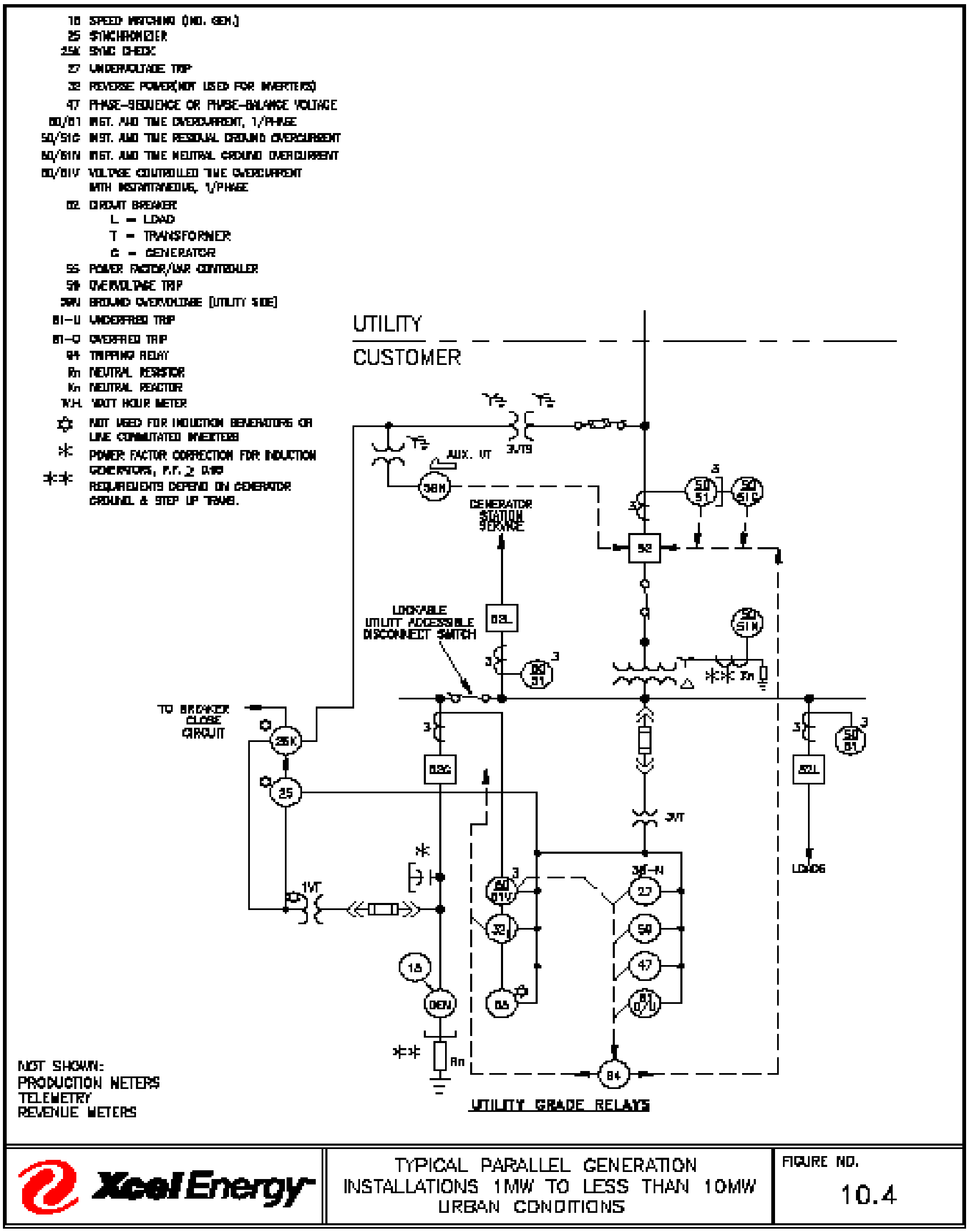


Xcel Energy	TYPICAL PARALLEL GENERATION INSTALLATIONS 10kW TO LESS THAN 100kW URBAN CONDITIONS	FIGURE NO. 10.2

10.3 100 KW – 1 MW

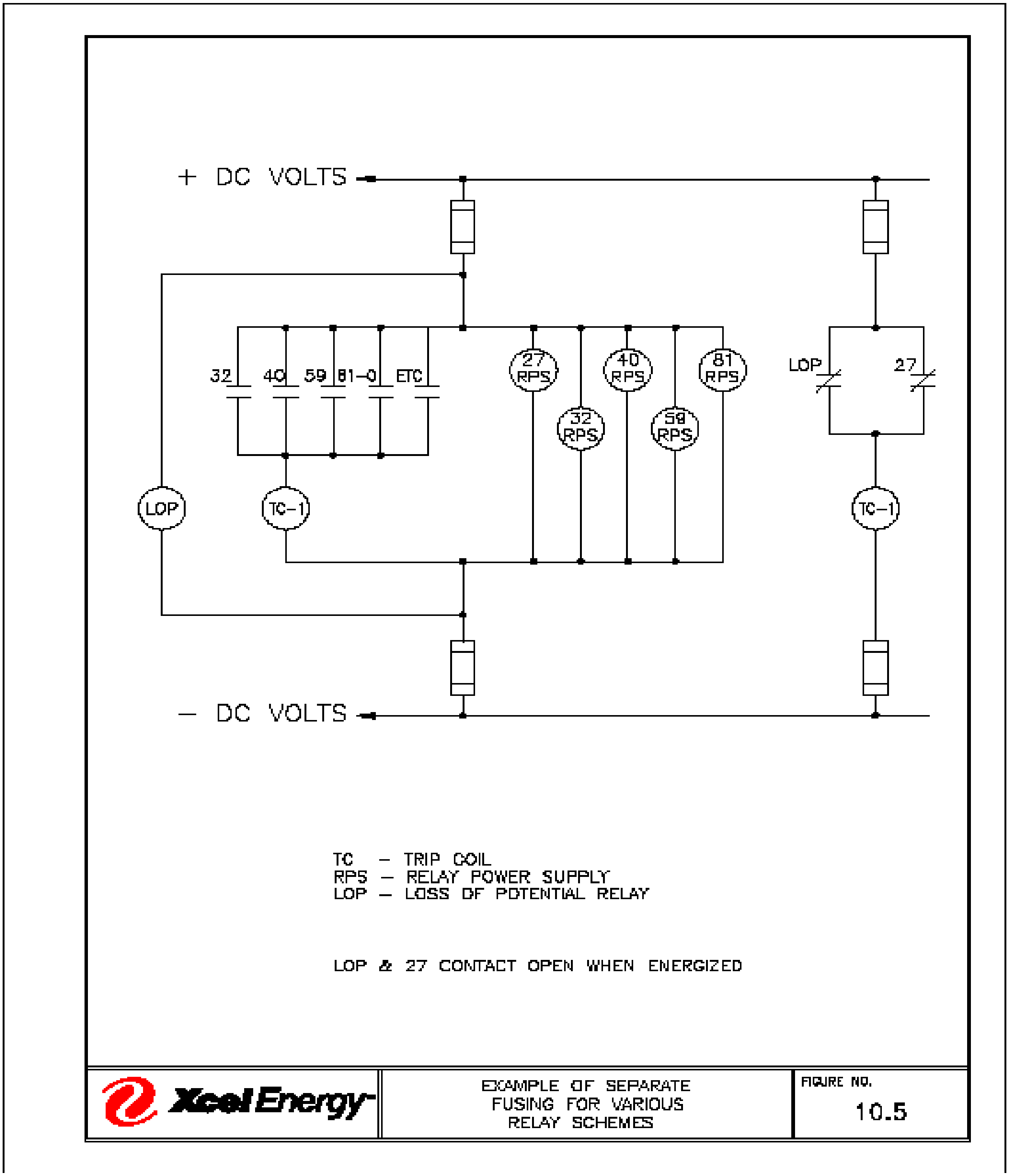


10.4 1 – 10 MW

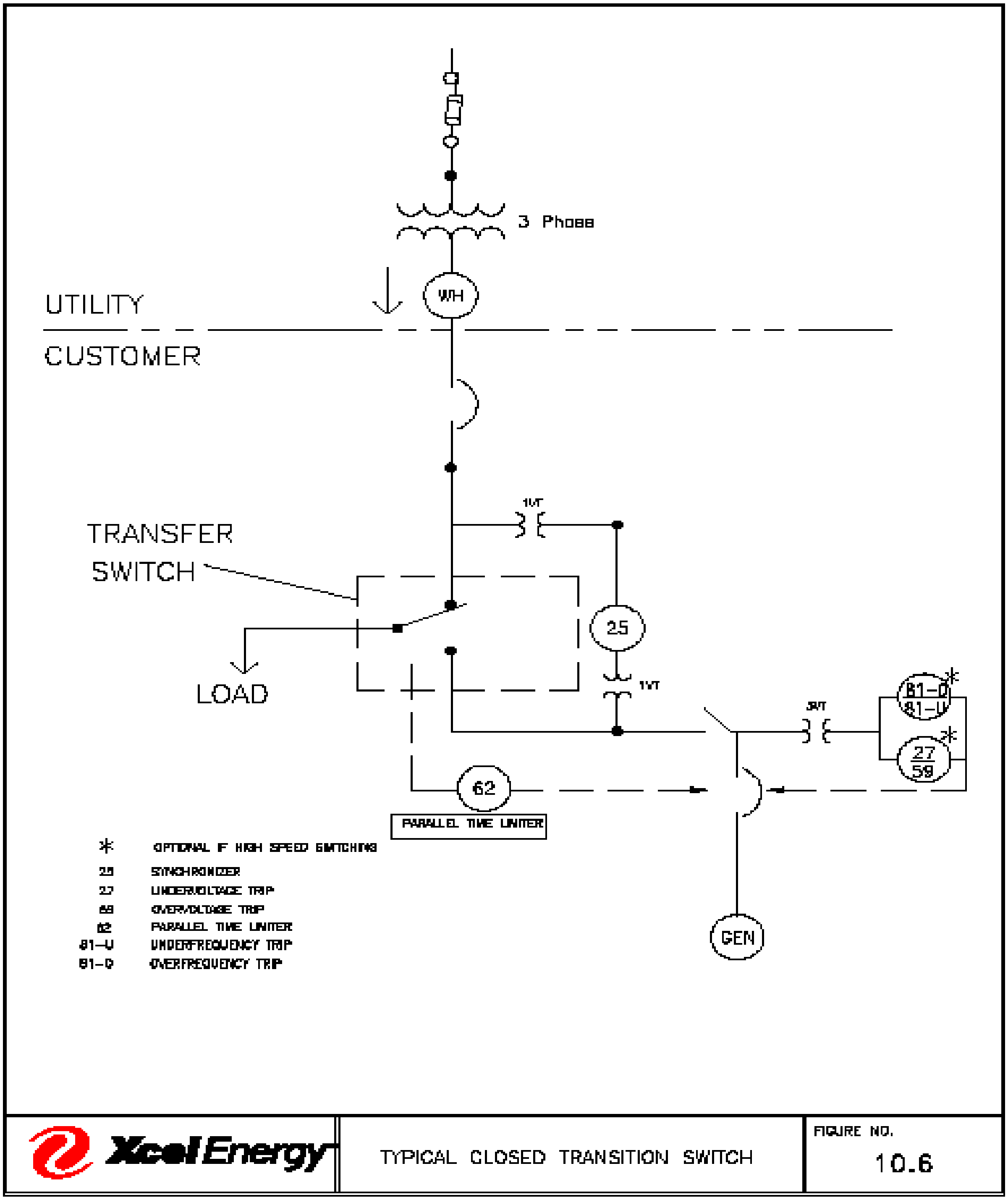


SPEED MATCHING (IND. GEN.)
SYNCHRONIZER
SYNC CHECK
27 UNDERVOLTAGE TRIP
32 REVERSE POWER(NOT USED FOR INVERTERS)
47 PHASE-SEQUENCE OR PHASE-BALANCE VOLTAGE
INST. AND TIME OVERCURRENT, 1/PHASE
50/51G INST. AND TIME RESIDUAL GROUND OVERCURRENT
INST. AND TIME NEUTRAL GROUND OVERCURRENT
VOLTAGE CONTROLLED TIME OVERCURRENT
WITH INSTANTANEOUS, 1/PHASE
CIRCUIT BREAKER
L = LOAD
T = TRANSFORMER
G = GENERATOR
POWER FACTOR/VAR CONTROLLER
OVERVOLTAGE TRIP
GROUND OVERVOLTAGE (UTILITY SIDE)
UNDERFREQ TRIP
OVERFREQ TRIP
TRIPPING RELAY
Rn NEUTRAL RESISTOR
Xn NEUTRAL REACTOR
W.H. WATT HOUR METER
NOT USED FOR INDUCTION GENERATORS OR
LINE COMMUTATED INVERTERS
POWER FACTOR CORRECTION FOR INDUCTION
GENERATORS
REQUIREMENTS DEPEND ON GENERATOR
GROUND & STEP UP TRANS.
UTILITY
CUSTOMER
AUX. VT
3VTS
GENERATOR
STATION
SERVICE
LOCKABLE
UTILITY ACCESSIBLE
DISCONNECT SWITCH
TO BREAKER
CLOSE
CIRCUIT
1VT
3VT
LOADS
GEN
Rn
NOT SHOWN:
PRODUCTION METERS
TELEMETRY
REVENUE METERS
UTILITY GRADE RELAYS
Xcel Energy
TYPICAL PARALLEL GENERATION
INSTALLATIONS 1MW TO LESS THAN 10MW
URBAN CONDITIONS
FIGURE NO.
10.4

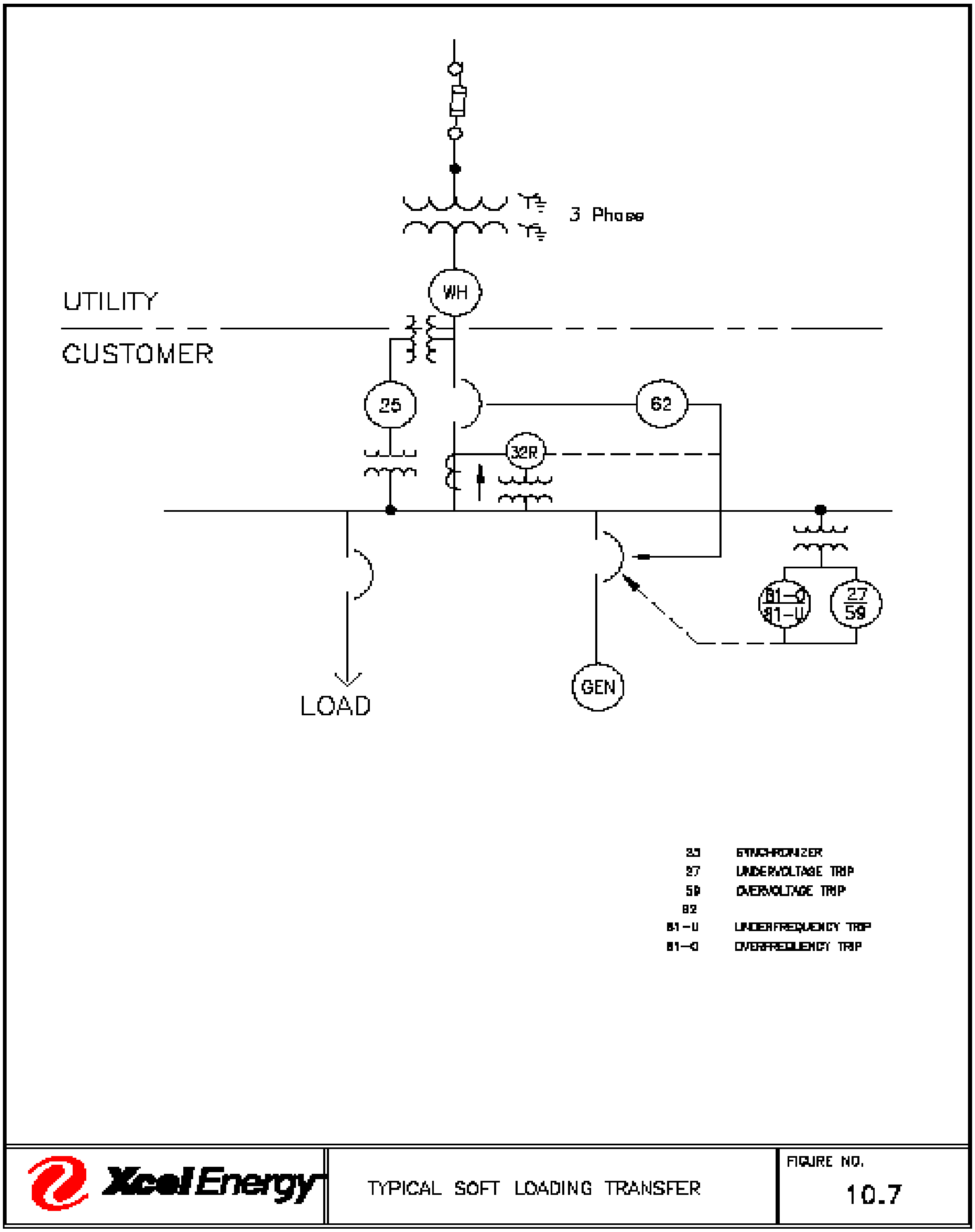
10.5 SEPARATE FUSING EXAMPLE



10.6 CLOSED TRANSITION SWITCH



10.7 SOFT LOADING TRANSFER



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.

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

Business Day - Monday through Friday, excluding holidays observed by the Utility.

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 "certified" when used in this text.

Company – Southwest Public Service d/b/a Xcel Energy - area electric power system (EPS) that serves the Local EPS. The Company has primary access to public rights-of-way, priority crossing of property boundaries, etc.

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

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

Feasibility Study - The study that identifies any potential adverse System impacts that would result from the interconnection of the Generating Facility.

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

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

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

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

Interconnection Customer - The party or parties who are responsible for meeting the requirements of this standard. This could be the Generation System applicant, installer, designer, owner, or operator.

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 request by an Interconnection Customer to interconnect a new Generating Facility, or to increase the capacity or make a material modification to the operating characteristics of an existing Generating Facility that is interconnected with the Utility's System.

Interconnection Costs - The reasonable costs of connection, switching, metering, transmission, distribution, safety provisions, and administration incurred by the Utility 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 Utility would have incurred if it had not engaged in interconnected operations but instead generated an equivalent amount of power itself or purchased an equivalent amount of power from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs pursuant to 17.9.570 NMAC.

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

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

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

Minimum Daytime Loading - The lowest 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.

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 Utility and the Interconnection Customer separately or in combination.

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

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

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

Quick Closed - A method of generation transfer that parallels for less than 100 msec with the Company and has suitable timers and interlocks that limit the parallel duration to less then 100 msec with the Company.

Qualifying Facility - A cogeneration facility or a small power production facility that meets the 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.

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

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

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

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

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

Soft Loading Transfer - A method of generation load transfer that parallels for typically less than 2 minutes to gradually transfer load between the generator and the Company. This is also called a "closed transition".

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

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

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

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

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

Upgrade - The required additions and modifications to the Utility'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 NMSA 62-3-3 (G) serving electric customers subject to the jurisdiction of the Commission.

12.0 REFERENCES

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

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

ANSI/IEEE Standard 142-1991, "IEEE Recommended Practice for Grounding of Industrial 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 P1547.2 (2008), "Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems"

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

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

Power Apparatus”

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

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

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

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

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

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

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

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

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

NESC – “National Electrical Safety Code”, ANSI C2-2002, Published by the Institute of Electrical and Electronics Engineers, Inc

13.0 NEW MEXICO STATE PUBLIC REGULATORY COMMISSION RULES

13.1 “17.9.568 – INTERCONNECTION OF GENERATION FACILITIES WITH A RATED CAPACITY UP TO AND INCLUDING 10 MW CONNECTING TO A UTILITY”

17.9.568.1 ISSUING AGENCY: New Mexico Public Regulation Commission.
[17.9.568.1 NMAC - N, 10/15/08]
17.9.568.2 SCOPE:
A. This rule, and the definitions, standards, procedures and screening processes described in the New Mexico *interconnection manual*, separately published and incorporated into this rule by reference, apply to every electric utility including rural electric cooperatives and investor-owned utilities operating within the state of New Mexico that is subject to the jurisdiction of the New Mexico public regulation commission. These standards and procedures apply to both qualifying and non-qualifying facilities.
B. The standards and procedures described in this rule (17.9.568 NMAC) and the **manual** apply only to the interconnection of generating facilities with a rated capacity up to and including 10 MW. The standards and procedures described in 17.9.569 NMAC apply to the interconnection of generating facilities with a rated capacity greater than 10 MW.
C. All interconnection contracts between a utility and an interconnection customer existing at the time 17.9.568 NMAC is adopted shall automatically continue in full force and effect. Any changes made to existing interconnection contracts shall conform to the provisions of 17.9.568 NMAC
[17.9.568.2 NMAC - N, 10/15/08]
17.9.568.3 STATUTORY AUTHORITY: This rule is adopted under the authority vested in this commission by the New Mexico Public Regulation Commission Act, NMSA 1978, Section 8-8-1 et seq. and the Public Utility Act, NMSA 1978, Section 62-3-1 et seq.
[17.9.568.3 NMAC - N, 10/15/08]
17.9.568.4 DURATION: Permanent.
[17.9.568.4 NMAC - N, 10/15/08]

17.9.568.5 EFFECTIVE DATE: October 15, 2008, unless a later date is cited at the end of a section
[17.9.568.5 NMAC - N, 10/15/08]

17.9.568.6 OBJECTIVE: The purpose of this rule and the **manual** is to set forth common interconnection requirements and a common interconnection process based on a common screening process for utilities and interconnection customers to expeditiously interconnect generating facilities with a rated capacity up to and including 10 MW in a safe and reliable manner. The parties shall use the procedures and forms set forth in this rule 17.9.568 NMAC and the **manual** for the interconnection of generating facilities with a rated capacity up to and including 10 kW. The parties shall use the procedures and forms in this rule 17.9.568 NMAC and the **manual** for the interconnection of generating facilities with a rated capacity greater than 10 kW and up to and including 10 MW unless they mutually agree to other procedures or forms that are consistent with the Public Utility Act.
[17.9.568.6 NMAC - N, 10/15/08]

17.9.568.7 DEFINITIONS: Terms used in this rule 17.9.568 NMAC shall have the following meanings.

A. Business day means Monday through Friday, excluding holidays observed by the utility.

B. Certified equipment package means 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 of test performed to certify the package under IEEE 1547.1.

C. Certified inverter means an inverter 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.

D. Distribution system means the utility's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

E. Distribution upgrade means the additions, modifications, and upgrades to the utility's distribution system at or beyond the point of common coupling 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.

F. Facilities study means the study that specifies and estimates the cost of the equipment, engineering, procurement, and construction work (including overhead costs) needed to implement the conclusions of the system impact study.

G. Feasibility study means the study that identifies any potential adverse system impacts that would result from the interconnection of the generating facility.

H. Generating facility means the interconnection customer's device for the production of electricity identified in the interconnection application, including all generators, electrical wires, equipment, and other facilities owned or provided by the interconnection customer for the purpose of producing electric power.

I. Grid network means a secondary network system with geographically separated network units where the network-side terminals of the network protectors are interconnected by low-voltage cables that span the distance between sites. The low-voltage cable circuits of grid networks are typically highly meshed and supplied by numerous network units. Grid network is also commonly referred to as area network or street network.

J. Highly seasonal circuit means a circuit with a ratio of annual peak load to the lowest monthly peak load greater than six (6).

K. Impact study means a 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. An impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.

L. Interconnection application means the request by an interconnection customer to interconnect a new generating facility, or to increase the capacity or make a material modification to the operating characteristics of an existing generating facility that is interconnected with the utility's system.

M. Interconnection customer means any person that proposes to interconnect its generating facility with the utility's system.

N. Interconnection facilities means the utility's interconnection facilities and the interconnection customer's interconnection facilities. Collectively, interconnection facilities include all facilities and equipment between the generating facility and the point of common coupling, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the generating facility to the utility's system. Interconnection facilities are sole use facilities and shall not include distribution upgrades.

O. Line section means that portion of a utility's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.
P. Manual means the New Mexico *interconnection manual* and its exhibits separately published and incorporated into this rule by reference.
Q. Network system means 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.
R. Network transformer means a transformer designed for use in a vault to feed a variable capacity system of interconnected secondaries.
S. Party means the utility and the interconnection customer separately or in combination.
T. Person, for purposes of this rule, means an individual, firm, partnership, company, rural electric cooperative organized under Laws 1937, Chapter 100 or the rural electric cooperative act, corporation or lessee, trustee or receiver appointed by any court.
U. Point of common coupling means the point where the interconnection facilities connect with the utility's system.
V. Primary network feeder means 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.
W. Power conversion unit (PCU) means an inverter or AC generator, not including the energy source.
X. Qualifying facility means a cogeneration facility or a small power production facility which meets the criteria for qualification contained in 18 C.F.R. Section 292.203.
Y. Rated capacity means the total AC nameplate rating of the power conversion unit(s) at the point of common coupling.
Z. Secondary network system means an AC power distribution system in which customers are served from three-phase, four-wire low-voltage circuits supplied by two or more network transformers whose low-voltage terminals are connected to the low-voltage circuits through network protectors. The secondary network system has two or more high-voltage primary feeders, with each primary feeder typically supplying multiple network transformers, depending on network size and design. The secondary network system includes automatic protective devices intended to isolate faulted primary feeders, network transformers, or low-voltage cable sections while maintaining service to the customers served from the low-voltage circuits.
AA. Small utility means a utility that serves less than 50,000 customers.
BB. Spot network means a secondary network system consisting of two or more network units at a single site. The low-voltage network side terminals of these network units are connected together with bus or cable. The resulting interconnection structure is commonly referred to as the "paralleling bus" or "collector bus." In spot networks, the paralleling bus does not have low-voltage ties to adjacent or nearby secondary network systems. Such spot networks are sometimes called isolated spot networks to emphasize that there are no low-voltage connections to network units at other sites.
CC. Study process means the procedure for evaluating an interconnection application that includes the scoping meeting, feasibility study, impact study, and facilities study.
DD. System means the facilities owned, controlled, or operated by the utility that are used to provide electric service under a utility's tariff.
EE. System emergency means a condition on a utility system that is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.
FF. Upgrade means the required additions and modifications to the utility's system at or beyond the point of common coupling. Upgrades do not include interconnection facilities.
GG. Utility means a utility or public utility as defined in NMSA 62-3-3 (G) serving electric customers subject to the jurisdiction of the commission.
[17.9.568.7 NMAC - N, 10/15/08]

17.9.568.8 APPLICABLE CODES AND STANDARDS:

A. The interconnection customer shall install, operate, and maintain the generating facility and the interconnection equipment in a safe manner in accordance with the rules for safety and reliability set forth in the latest editions of the *national electrical code*, other applicable local, state, and federal electrical codes, and prudent electrical practices.
B. In order to qualify for any interconnection procedures, each generating facility generator shall be in conformance with the following codes and standards as applicable:
(1) IEEE 1547 standard for interconnecting distributed resources with electric power systems or equivalent IEEE 1547.1;
(2) IEEE standard conformance test procedures for equipment interconnecting distributed resources

with electric power systems or equivalent; and
(3) UL 1741 Inverters, converters and controllers for use in independent power systems or equivalent.
C. The interconnection equipment package shall be considered certified for interconnected operation if the equipment package 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.
D. The generating facility shall be designed to conform with all of the applicable requirements in the **manual**.
[17.9.568.8 NMAC - N, 10/15/08]
17.9.568.9 INTERCONNECTION APPLICATION:
A. An interconnection customer shall submit its interconnection application to the utility using **manual** exhibit 1A or 1B as applicable, together with the fees specified in 17.9.568.12 NMAC. The utility shall record the date and time on the face of the interconnection application upon receipt by the utility. The original date and time recorded by the utility on the interconnection application at the time of its original submission shall be accepted as the date and time on which the interconnection application was received for the purposes of any timetable established in this rule or the **manual**. Following submission of the interconnection application, the parties will follow the procedures and time requirements described in the **manual**.
B. The utility shall place interconnection applications in the order they are received. The order of each interconnection application will be used to determine the cost responsibility for the upgrades necessary to accommodate the interconnection. At the utility's option, interconnection applications may be studied serially or in clusters for the purpose of the system impact study.
[17.9.568.9 NMAC - N, 10/15/08]
17.9.568.10 INTERCONNECTION APPLICATION REVIEW PROCESS: The utility shall utilize the interconnection screening process and the screen criteria described in the **manual**. That screening process results in the application of one of the three general review paths described as follows:
A. simplified interconnection: for certified inverter-based facilities with a power rating of 10 kilowatts (kW) or less on radial or network systems under certain conditions;
B. fast track: for certified generating facilities that pass certain specified screens; or
C. full interconnection study: for generating facilities that have a power rating of 10 megawatts (MW) or less and do not qualify for the screens under the simplified interconnection process or fast track process.
[17.9.568.10 NMAC - N, 10/15/08]
17.9.568.11 INTERCONNECTION APPLICATION REVIEW FLOW CHART AND SCREEN CRITERIA: Utilities shall use the screen criteria described in the **manual** to evaluate all interconnection applications.
[17.9.568.11 NMAC - N, 10/15/08]
17.9.568.12 GENERAL PROVISIONS APPLICABLE TO INTERCONNECTION APPLICATIONS:
A. An interconnection customer shall pay the following application fee to the utility at the time it delivers its interconnection application to the utility:
(1) $50 if the proposed generating facilities will have a rated capacity less than or equal to 10 kW;
(2) $100 if the proposed generating facilities will have a rated capacity greater than 10 kW and less than or equal to 100 kW; or
(3) $100 + $1 per kW if the proposed generating facilities will have a rated capacity greater than 100 kW.
B. In addition to the fees authorized by this rule, a small utility may collect from the interconnection customer the reasonable costs incurred to obtain necessary expertise from consultants to review interconnection applications for generating facilities with rated capacities greater than 10 kW. A small utility shall provide a good faith estimate of the costs of such consultants to an interconnection customer within ten (10) business days of the date the interconnection application is delivered to the utility.
C. Commissioning tests of the interconnection customer's installed equipment shall be performed pursuant to applicable codes and standards, including IEEE 1547.1 “IEEE standard conformance test procedures for equipment interconnecting distributed resources with electric power systems.” A utility must be given at least five (5) business days written notice of the tests, or as otherwise mutually agreed to by the parties, and may be present to witness the commissioning tests. An interconnection customer shall reimburse a utility for its costs associated with witnessing commissioning tests performed pursuant to the **manual** except that a utility may not charge a fee in addition to the application fee for the cost of witnessing commissioning tests for inverter-based generating facilities that have rated capacities that are less than or equal to 25 kW.
D. If an interconnection customer requests an increase in capacity for an existing generating facility, the interconnection application shall be evaluated on the basis of the new total capacity of the generating facility. If an interconnection customer requests interconnection of a generating facility that includes multiple energy

production devices at a site for which the interconnection customer seeks a single point of common coupling, the interconnection application shall be evaluated on the basis of the aggregate capacity of the multiple devices.

F. All interconnection applications shall be evaluated using the maximum rated capacity of the proposed generating facility.

G. The commission may designate a facilitator to assist the parties in resolving disputes related to this rule and the **manual**. The parties to a dispute will be responsible for the costs of dispute resolution, if any, as determined by the facilitator subject to review by the commission.

H. Confidential information shall remain confidential unless otherwise ordered by the commission. Confidential information shall mean any confidential and proprietary information provided by one party to the other party that is clearly marked or otherwise designated "confidential".

[17.9.568.12 NMAC - N, 10/15/08]

17.9.568.13 GENERAL PROVISIONS APPLICABLE TO UTILITIES:

A. A utility shall interconnect any interconnection customer that meets the interconnection criteria set forth in this rule and in the **manual**. A utility shall make reasonable efforts to keep the interconnection customer informed of the status and progress.

B. Utilities shall reasonably endeavor to aid and assist interconnection customers to insure that a proposed generating facility's interconnection design, operation, and maintenance are appropriate for connection to the utility's system. This may include consultations with the interconnection customer and its engineering and other representatives.

C. Utilities shall make reasonable efforts to meet all time frames provided for in this rule unless a utility and an interconnection customer agree to a different schedule. If a utility cannot meet a deadline provided herein, it shall notify the interconnection customer, explain the reason for its inability to meet the deadline, and provide an estimated time by which it will complete its activity.

D. Utilities shall use the same reasonable efforts in processing and analyzing interconnection applications from all interconnection customers, whether the generating facility is owned or operated by the utility, its subsidiaries or affiliates, or others.

E. Utilities shall maintain records for three years of each interconnection application received, the times required to complete each interconnection application approval or disapproval, and justification for the utility's disapproval of any interconnection application.

F. Utilities shall maintain current, clear and concise information regarding this rule including the name, telephone number, and email address of contact persons. The information shall be easily accessible on the utility's website beginning within one month of the effective date of this rule, or the information may be provided in bill inserts or separate mailings sent no later than one month after the effective date of this rule and no less often than once each year thereafter. Each utility shall maintain a copy of this rule and the **manual** at its principal office and make the same available for public inspection and copying during regular business hours.

G. A small utility that uses a consultant to review a proposal to interconnect a generating facility with the small utility's system may extend each of the time deadlines for review of the fast track process by a period not to exceed twenty (20) business days provided that the small utility shall make a good faith effort to complete the review sooner.

H. Compliance with this interconnection process does not constitute a request for, nor provision of any transmission delivery service, or any local distribution delivery service. Interconnection under this rule does not constitute an agreement by the utility to purchase or pay for any energy, inadvertently or intentionally exported.

[17.9.568.13 NMAC - N, 10/15/08]

17.9.568.14 GENERAL PROVISIONS APPLICABLE TO INTERCONNECTION CUSTOMERS:

A. The cost of utility system modifications required pursuant to the fast track process or the full interconnection study process shall be borne by the interconnection customer unless otherwise agreed by the parties.

B. An interconnection customer shall have thirty (30) business days (or other mutually agreeable period) following receipt of an interconnection agreement to execute the agreement and return it to the utility. If the interconnection customer does not execute the interconnection agreement and return it to the utility within the applicable period, the interconnection application shall be deemed withdrawn. After all parties execute an interconnection agreement, interconnection of the generating facility shall proceed under the provisions of the interconnection agreement.

C. An interconnection customer is responsible for the prudent maintenance and upkeep of its interconnection equipment.

D. Upon the petition of a utility, for good cause shown, the commission may require a customer with a generating facility with a rated capacity of 250 kW or less to obtain general liability insurance prior to connecting with a public utility. A utility may require that an interconnection customer proposing to connect a generating facility with a rated capacity greater than 250 kW provide proof of insurance with reasonable limits not to exceed $1,000,000 or other reasonable evidence of financial responsibility.

[17.9.568.14 NMAC - N, 10/15/08]

17.9.568.15 SAFETY PROVISIONS:

A. An interconnection customer shall separate from the utility system in the event of any one or more of the following conditions:

(1) a fault on the generating facility's system; or

(2) a generating facility contribution to a utility system emergency; or

(3) abnormal frequency or voltage conditions on the utility's system; or

(4) any occurrence or condition that will endanger utility employees or customers; or

(5) a generating facility condition that would otherwise interfere with a utility's ability to provide safe and reliable electric service to other customers; or

(6) the sudden loss of the utility system power.

B. A visible-open, load break disconnect switch between the generating facility and the utility system that is visibly marked "generating facility generation disconnect" and is accessible to and lockable by the utility is required for all generating facilities except for those generating facilities with a maximum capacity rating of 10 kW or less that use a certified inverter including a self-contained renewable energy certificate (REC) meter and either:

(1) a utility accessible AC load break disconnect; or

(2) a utility accessible DC load break disconnect where there is no other source of generated or stored energy connected to the system.

C. Interconnection customers shall post a permanent and weather proof one-line electrical diagram of the generating facility located at the point of service connection to the utility. Generating facilities where the disconnect switch required by Subsection B of 17.9.568.15 NMAC is not located in close proximity to the utility meter must post a permanent and weather proof map showing the location of all major equipment including the utility meter point, the generating facility generation disconnect, and the generating facility generation breaker. Non-residential generating facilities larger than 10 kW shall include with or attached to the map the names and current telephone numbers of at least two persons authorized to provide access to the generating facility and who have authority to make decisions regarding the generating facility interconnection and operation.

D. If the generating facility interconnection equipment package is not certified or if a certified equipment package has been modified, the generating facility interconnection equipment package shall be reviewed and approved by a professional electrical engineer, registered in the state of New Mexico.

[17.9.568.15 NMAC - N, 10/15/08]

17.9.568.16 VARIANCES: A party may file a request for a variance from the requirements of this rule. Such application shall describe the reasons for the variance; set out the effect of complying with this rule on the parties and the utility's customers if the variance is not granted; identify the section(s) of this rule for which the variance is requested; describe the expected result which the request will have if granted; and state how the variance will aid in achieving the purposes of this rule. The commission may grant a request for a procedural variance through an order issued by the chairman, a commissioner or a designated hearing examiner. Other variances shall be presented to the commission as a body for determination.

[17.9.568.16 NMAC - N, 10/15/08]

13.2 THE NEW MEXICO INTERCONNECTION MANUAL

The following is an imbedded pdf file of the NM Interconnection Manual. Double click on the "page".

THE NEW MEXICO INTERCONNECTION MANUAL

(To be Used in Conjunction with New Mexico Public Regulation Commission Rule 17.9.568 NMAC, Interconnection of Generating Facilities with a Rated Capacity Up to and Including 10 MW Connecting to a Utility System)

New Mexico Public Regulation Commission
P. O. Box 1269
1120 Paseo de Peralta
Santa Fe, New Mexico 87504

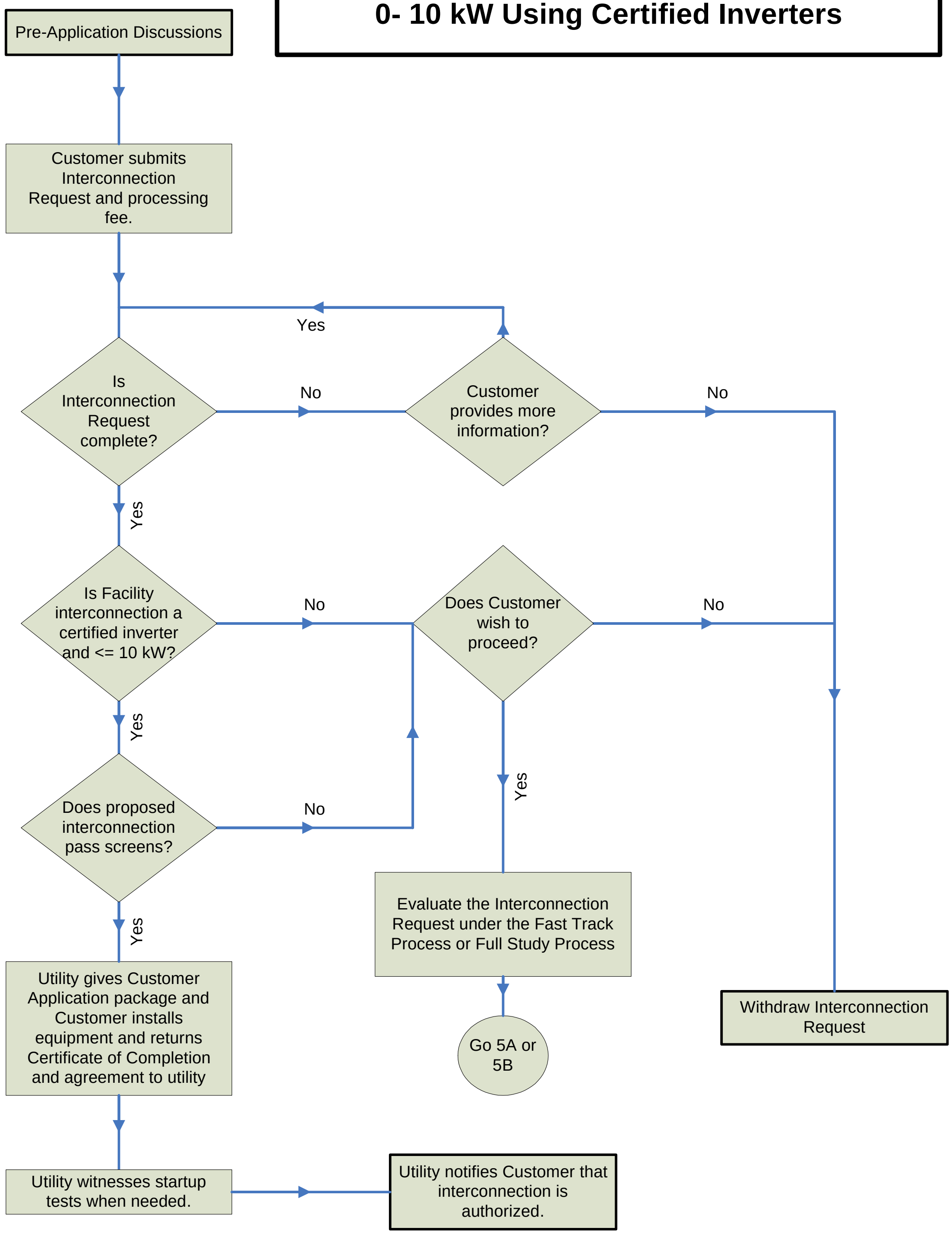
Publication Date: July 29, 2008

14.0 PROCESS FLOW CHARTS

for the New Mexico interconnection 568 Rules

Attachment 5 A

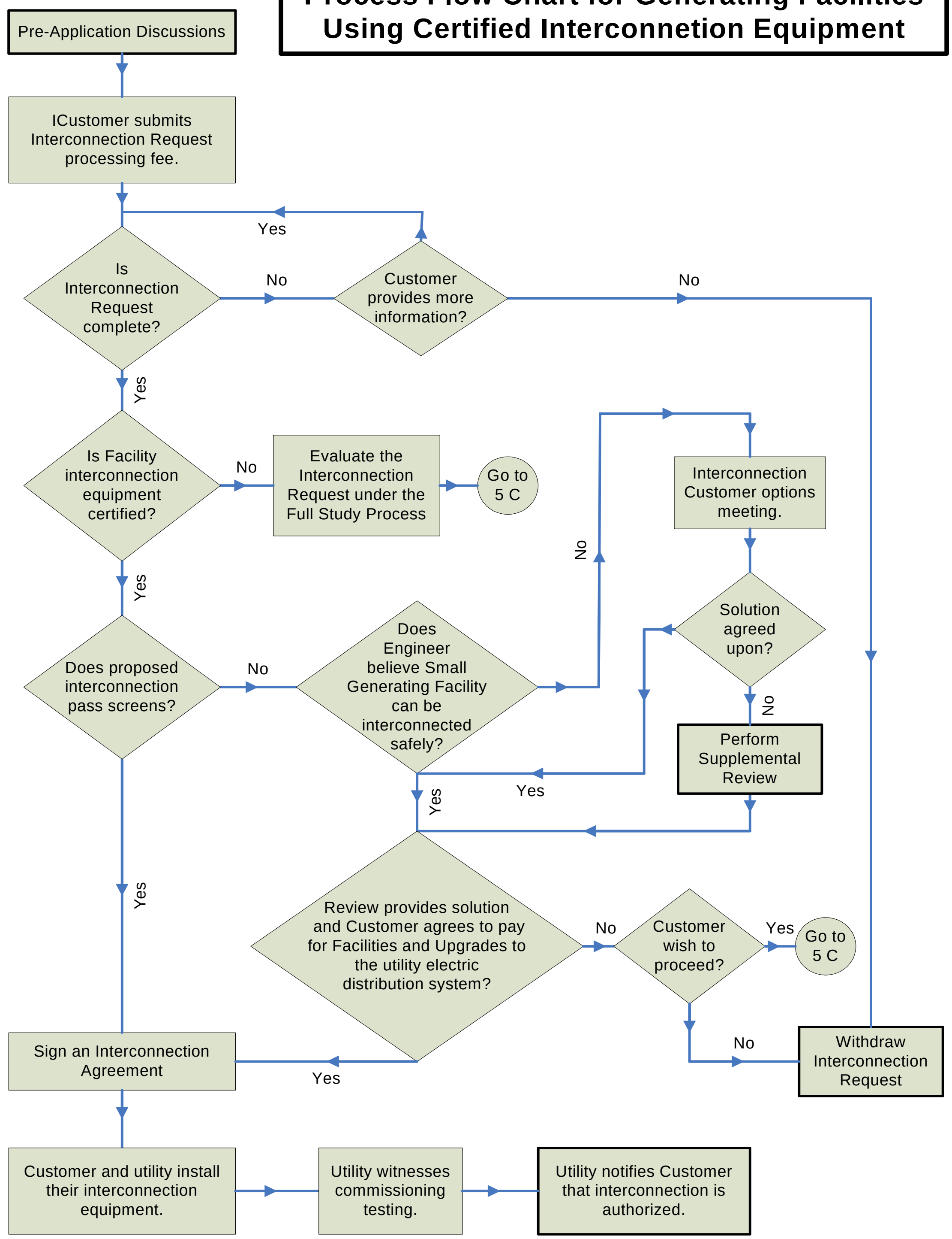
New Mexico Simplified Interconnection Process Flow Chart for Generating Facilities 0- 10 kW Using Certified Inverters



Draft 1, 6-19-07

Attachment 5 B

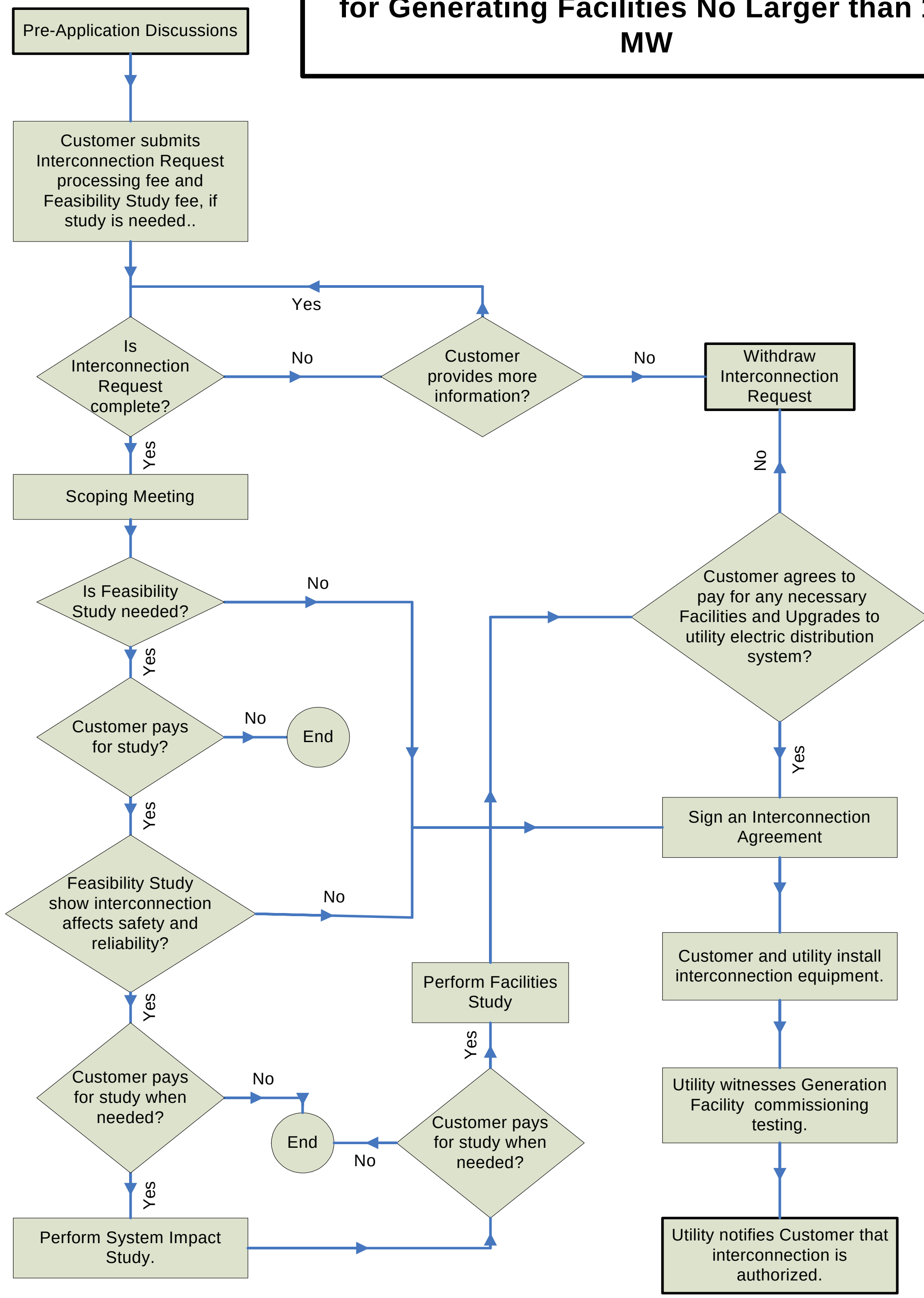
New Mexico Fast Track Interconnetion Process Flow Chart for Generating Facilities Using Certified Interconnetion Equipment



Draft Version 1, 6-18-07

Attachment 5 C

New Mexico Full Study Process Flow Chart for Generating Facilities No Larger than 10 MW



Draft Version 1, 6-18-07

15.0 TYPICAL SMALL DG SITE-PLAN

Note: Legible hand drawn site plans are acceptable