CITY OF Longmont

Power & Communications

INTERCONNECTION STANDARDS FOR DISTRIBUTED ENERGY RESOURCES

January 1, 2025

Reviewed and Approved:

DocuSigned by:
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City Manager — 4/16/2025 | 2:57 PM MDT
Date

Director of Electric Services — 3/3/2025
Date

Director of Electrical Engineering — 2-27-25
Date

Revisions:

These Interconnection Standards will be reviewed annually, and revisions will be made in accordance with the following:

Technical Revisions: Technical revisions shall consist solely of such additions, revisions, and corrections to these Interconnection Standards as may, in the judgment of Longmont Power & Communications, be necessary to better conform to safe and sound engineering and operational standards and practice, to better clarify existing requirements, or are required to maintain regulatory compliance. Technical revisions shall become effective when approved, in writing, by the Director of Electric Services and the Director of Electrical Engineering.

Revision Descriptions

Revision Description	Revised By	Approved

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1 Intent, Scope, and Application

1.1 Intent

This document outlines the minimum requirements for safe and reliable interconnection of customer-owned, non-utility Distributed Energy Resources (DER) with Longmont Power & Communications' (LPC's) distribution system.

The operation and design of all DER must meet the requirements contained in this document, any written agreement between LPC and the DER Operator, any applicable requirements contained in Chapter 14 of the Longmont Municipal Code, and LPC's Design Standards and Construction Specifications. Any DER not explicitly described in this document will require study before it can be approved to interconnect with LPC.

1.2 Scope

The requirements contained in this document apply to all DER that will operate, for sustained periods or momentarily, while electrically connected to the LPC distribution system.

The requirements in this document do not apply to back-up generation or systems that are incapable of electrical interconnection to the LPC distribution system. Such systems will require an open transition ('break before make') switch to transfer customer load from the LPC distribution system to the Local Electric Power System (local EPS) and back again.

All connections to the LPC distribution system and any aspect of such connection are subject to LPC review, must be in accordance with the requirements contained in LPC's Design Standards and Construction Specifications, and shall not be permitted unless approved by LPC.

1.3 Application of Policy

Requirements in this revision apply to all projects with a building permit application date and/or interconnection application date after the revision date of this document.

2 General Requirements

2.1 System Phase and Voltage

The Operator's DER system must match the service voltage supplied by LPC. Single-phase DER must interconnect at 240 nominal volts.

All three-phase DER must be effectively grounded, and the interconnection must be made via a four-wire grounded wye system.

Three-phase DER must be able to detect an open-phase condition, cease to energize, and trip in accordance with the most current IEEE 1547 requirements.

2.2 System Reclosing

In the cases and locations where automatic circuit reclosing is used, the DER must disconnect

from the LPC distribution system when an automatic reclose occurs. Normally, the DER must not interfere with automatic reclosing where it is utilized; however, industry standards require that a DER must automatically disconnect from an islanded system in accordance with the latest IEEE 1547 requirements.

2.3 Islanding

Islanding occurs when a DER becomes disconnected from the main utility generation source on the LPC distribution system but continues to independently serve a portion of the LPC distribution system. When system penetration levels of DER become large enough, undesirable islanding of portions of the LPC distribution system are feasible and additional protective devices or systems, such as transfer trip equipment, may be required for safe operation. All costs associated with this additional equipment will be the responsibility of the interconnecting DER Operator.

When interconnecting DER, proper system protection and voltage stability must be maintained. All DER must be equipped with protective devices and controls designed to prevent the DER from being connected to a de-energized, or partially energized, LPC distribution system. Islanding is not permitted on the LPC distribution system without written agreement between LPC and the DER Operator.

2.4 Synchronizing

The DER must synchronize with the LPC distribution system automatically. Any proposal utilizing manual synchronization is subject to review and must be approved by LPC. All DER must use protective devices that prevent electrically closing a DER that is out of synchronization with the LPC distribution system. Under no circumstances will LPC be responsible or liable for any damage caused by an out-of-synchronization closure of a DER onto the LPC distribution system. The Operator is responsible and liable for any damage caused by any type of improper closing onto the system.

2.5 Improper Operation of the DER

DER must not adversely impact the operation of the LPC distribution system in any way. Adverse impacts to the LPC distribution system include, but are not limited to, the following:

a) Unbalanced currents or voltages

b) Voltages outside of acceptable ranges as described in section 6 of this document

c) Impact to bulk electric system nominal frequency deviating from the normal 60 Hz

d) Injection of Direct Current (DC) or harmonics into the system beyond what is allowed by this document

e) Any operation that causes excessive operations of system voltage regulating devices, such as load tap changers and voltage regulators

f) Any operation that affects system grounding or ground fault protection

If the DER causes unusual fluctuations or disturbances on, or interference with, the LPC

distribution system or other LPC customers, LPC has the right to require the DER Operator to cease operation until such time as the DER Operator can demonstrate to LPC that it has remedied the problem and can operate the DER in compliance with these requirements.

LPC has the right to require the DER Operator to install supplemental devices to reasonably correct or limit such fluctuation, disturbance, or interference at no expense to LPC or other customers.

2.6 DER Categories

Different types of DER have different capabilities and are expected to respond differently when experiencing both normal and abnormal conditions; therefore, some requirements set forth in this standard differ based on the type of DER.

2.6.1 Category A1

This category is adequate for applications where the DER penetration is lower and where the DER power output is not subject to frequent, large variations. Operational requirements closely align with those described in IEEE 1547 as Category A, related to reactive power capability and voltage regulation performance, and Category I, related to abnormal operating performance.

The types of DER included in Category A1 include, but are not limited to the following:

- Synchronous generators, excluding those used in wind turbines

2.6.2 Category B2

This category typically includes DER where the power output is subject to frequent, large variations. Operational requirements closely align with those described in IEEE 1547 as Category B, related to reactive power capability and voltage regulation performance, and Category II, related to abnormal operating performance.

The types of DER included in Category B2 include, but are not limited to the following:

- Inverters sourced by solar photovoltaic (PV), fuel cells, or energy storage, including vehicle-to-grid (V2G) capable electric vehicles and all other inverter applications
- Wind turbines (all types)
- Induction generators, including doubly fed

2.7 DER Size Classifications

DER size classifications consider the size and potential impact of the proposed DER on the LPC distribution system.

2.7.1 Class 1

Class 1 is DER less than 50 kVA.

The typical installation in this class is residential rooftop solar, or installations that are tied to commercial and industrial services.

2.7.1.1 Class 1R

This subclass is for residential single-phase installations that meet the sizing guidelines outlined in section 2.8.1.

2.7.2 Class 2

Class 2 is DER of 50 kVA up to, but not including 1,000 kVA. Systems of this size may require a production meter.

Class 2 systems sized 100 kVA and greater will require additional provisions for system protection, grounding, metering, and telemetry as outlined in this document and application review by Platte River Power Authority (PRPA) is required.

The typical installations in this Class are commercial and industrial installations and community solar gardens.

2.7.3 Class 3

Class 3 is DER of 1,000 kVA and greater. Systems of this size require additional provisions for system protection, grounding, monitoring, and communication as outlined in this document, as well as coordination with PRPA on compensation and interconnection standards. A dedicated feeder for Class 3 systems may be necessary.

The typical installation in this Class is a front of the meter DER site.

2.8 DER System Sizing Guidelines

2.8.1 Residential

For property owner owned DER to qualify as Class 1R, system sizing is limited by the rules listed below. LPC will approve the proposed system size if either of the following conditions is met:

a) DER generation is less than 200% of previous year's energy usage (kWh), OR

b) DER size is less than 12 kVA

For DER that are not owned by the property owner, generation is limited to 120% of the previous year's energy usage (kWh).

If the total size of the DER is greater than either of the conditions listed above, the Applicant may submit a variance request with documentation supporting their case for an oversized system. LPC may approve variances related to electrification of customer loads or anticipated increases in energy use on a case-by-case basis.

For customers without energy usage history, for example, new construction or new ownership, a, 6 kWh/square foot per year allowance will be used to estimate the annual electricity

consumption based on the total conditioned floor space as referenced in Boulder County records. This allowance can also be used to address unique circumstances with the adoption of electrification measures when the standard system size shown in 2.8.1.b above is insufficient for the anticipated electric load.

2.8.2 Commercial / Industrial

Property owner owned, behind the meter DER installations are limited to 200% of the previous years' energy usage (kWh).

For DER that are not owned by the property owner, generation is limited to 120% of the previous year's energy usage (kWh).

DER with an aggregated generation capacity of 100 kVA or larger at the point of common coupling (PCC) are subject to additional requirements as outlined in this document.

2.9 DER Application Analysis

Interconnection applications may, at the sole discretion of LPC, be reviewed for conformance with some or all the following criteria. A study will be performed using both existing and proposed DER ratings and will vary based upon the size, type, specifications, and features of the individual project application. Whenever one or more of the following limitations are exceeded, additional study is required. LPC may require additional analysis, equipment upgrades, and/or modifications to the DER prior to approval.

a) After the addition of the **proposed DER**, the total rated DER kVA interconnected for all customers connected via the distribution transformer equals or exceeds 100% of the transformer's rating.

b) After the addition of the **proposed single-phase DER**, the total rated DER kVA interconnected via shared secondary equals or exceeds 25 kVA.

c) After the addition of the **proposed single-phase DER**, an imbalance greater than 90 kVA of single-phase DER export capacity exists between two phases of the feeder or portion of the feeder.

d) After the addition of the **proposed single-phase, non-inverter connected DER**, the total rated non-inverter connected DER kVA interconnected via the single-phase transformer equals or exceeds 20 kVA.

e) After the addition of the **proposed DER,** the phase current imbalance for a three-phase system as measured at the PCC, must not be greater than 10% at any time.

f) After the addition of the **proposed PV DER**, the total rated DER kVA on the feeder or portion of the feeder equals or exceeds 80% of the previous year's daytime minimum (7am – 7pm) load (DML) on that feeder or feeder section.

g) After the addition of the **proposed non-PV DER**, the total rated DER kVA on the feeder or portion of the feeder equals or exceeds 80% of the previous year's minimum load on that feeder or feeder section.

h) After the addition of the **proposed DER**, the total fault current at the nearest upstream

protective device equals or exceeds 90% of the device's short circuit interrupting rating.

i) After the addition of the **proposed DER**, the total fault current, measured at the high voltage side of the interconnection transformer, increases by more than 10% of the previous maximum fault current.

j) After the addition of the **proposed DER**, the short circuit contribution ratio for a line-ground fault, calculated at the high voltage side of the interconnection transformer, is greater than 3%.

k) The **proposed DER includes an induction machine** 100 kVA or greater, or an aggregate of 100 kVA of induction generators.

2.10 DER Application Review

DER interconnection applications may, at the sole discretion of LPC, be reviewed as detailed below. The specific analysis, will vary based upon the specifics of the application, including DER system size, generation type, specifications, features, and location of DER interconnection within the LPC distribution system.

All required studies will be performed by LPC or its authorized subcontractor. The Applicant is responsible for the actual costs of the studies.

As part of the DER permit application process, LPC will conduct a completeness check to determine whether the Applicant has submitted all materials necessary to process the application. If the application is deemed sufficient, it will proceed to either the Feasibility Study or System Impact Study. If the application is deemed insufficient, a written list of the incomplete information will be sent to the Applicant to be updated and resubmitted.

2.10.1 Feasibility Study

The purpose of the Feasibility Study is to identify potential localized impacts of the Applicant's proposed DER, and other approved DER, on the LPC distribution system, using the criterion identified in section 2.9 Application Analysis. See Appendix A for process flow details.

The Feasibility Study has two main outcomes:

1) The application passes, the Applicant receives a signed interconnection agreement from LPC and proceeds with DER installation.

2) The Feasibility Study identifies LPC distribution system issues that must be addressed before the application can move forward. The results of the Feasibility Review will be discussed with the Applicant, LPC will provide a detailed review of the identified issues along with the costs of required secondary (600V) and/or primary (200A, 15kV) LPC distribution system modifications or the costs for additional application review. After consideration of the review findings, the Applicant can choose to:

    (a) Modify the application and resubmit for a Feasibility Review.

    (b) Agree to identified modifications to the secondary (600V) and/or primary

(200A, 15kV) LPC distribution system and submit payment for construction costs.

(c) Agree to move application to the System Impact Study to further investigate the identified issues that affect the primary (600A,15 kV) LPC distribution system and submit payment for the study.

(d) Withdraw application.

2.10.2 System Impact Study

The purpose of the System Impact Study is to evaluate the broader impact of the Applicant's proposed DER on the LPC distribution system. The System Impact Study is an engineering review that will identify areas where the LPC distribution system will need to be modified to accommodate the proposed DER as designed and will provide budgetary cost estimates for those modifications to facilitate the decision making of the Applicant. See Appendix B for process flow details.

Components of a System Impact Study may include but are not limited to the following analyses:

1) Safety and System Operations
2) Communications Requirements
3) Load Flow
4) Short Circuit
5) Protection and Coordination
6) Power Quality
7) Transmission Level Impacts

The System Impact Study is required in the following scenarios:

1) During an Applicant's Feasibility Study, potential issues affecting the primary (15kV) LPC distribution system were identified.
2) Characteristics of the proposed DER warrant bypassing the Feasibility Study and moving an application directly to the System Impact Study. This determination will be made solely by LPC.

The results of the System Impact Study will be discussed with the Applicant, LPC will provide an overview of the identified issues along with budgetary costs of required LPC distribution system modifications. The timeline and costs for a Facilities Study review will also be provided. After consideration of the study findings, the Applicant can choose to:

1) Move the proposed DER interconnection application to the Facilities Study level and submit payment of the study fee.

2) Withdraw application.

2.10.3 Facilities Study

The purpose of the Facilities Study is to provide the Applicant with a comprehensive summary of the modifications identified in the System Impact Study. The summary will include a timeline and cost estimate for all construction and equipment which may include items such as transformers, circuit breakers, reclosers, protective relays, metering, communication equipment, circuit reconductoring, LPC distribution system extensions and transmission system modifications.

A Facilities Study is performed after the Applicant receives the results of the System Impact Study and agrees to move forward with the additional study.

After consideration of the study findings, the Applicant can choose to:

1) Agree to the modifications identified in the Facilities Study and submit payment for construction costs.

2) Withdraw application.

2.11 DER Study Cost and Timeline

The Applicant will be provided a non-binding, good faith estimate of the study cost and timeline. The Applicant must pay the estimate before the study will start. The Applicant is responsible for the actual costs of the study. If the actual cost of the study is lower than the provided estimate, the excess funds will be refunded to the Applicant. If the actual cost of the study exceeds the provided estimate, the Applicant will be invoiced for the additional funds required to complete the study.

The cost and timeline of the required DER studies will be based on standard system review procedures established by LPC.

2.12 Submittal Requirement

The Applicant must submit DER design and specification drawings and documents to LPC. LPC is entitled to review and approve or reject DER prior to their installation and energization. The Operator agrees to incorporate any reasonable design changes requested by LPC prior to, during, or after installation of the DER. LPC's approval or acceptance of any design and specification information related to the DER to be installed must not be construed as an endorsement of such engineering plans, specifications, or other information.

The specific submittal requirements can be found in the **LPC DER Submittal Checklist**.

3 Standards and Definitions

3.1 Standards

Unless otherwise specified in this standard, the current edition of the following standards shall be complied with in DER design, choice of equipment, and interconnection design.

ANSI C84.1: American National Standard for Electric Power Systems and Equipment- Voltage ratings (60 Hertz)

IEEE 18: IEEE Standard for Shunt Power Capacitors

IEEE 57.32: IEEE Standard Requirements, Terminology, and Test Procedures for Neutral Grounding Devices

IEEE 141: IEEE Recommended Practice for Electric Power Distribution for Industrial Plants

IEEE 142: IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems

IEEE 242: IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems

IEEE 519: Recommended Practices and Requirements for Harmonic Control in Electric Power Systems

IEEE 665: IEEE Standard for Generation Station Grounding

IEEE 1015: IEEE Recommended Practice for Applying Low-Voltage Circuit Breakers Used in Industrial and Commercial Power Systems

IEEE 1036: IEEE Standard for Application of Shunt Power Capacitors

IEEE 1453: Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems

IEEE 1547: IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces

IEEE 1547.1: IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

IEEE 1547.2: IEEE Application Guide for IEEE Std. 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

IEEE 1547.7: IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection

IEEE C2: National Electrical Safety Code

IEEE C37.06: IEEE Standard for AC High-Voltage Circuit Breakers rated on a Symmetrical Current Basis-Preferred Ratings and Required Capabilities.

IEEE C37.012: IEEE Application Guide for Capacitor Current Switching for AC High-Voltage Circuit Breakers

IEEE C37.66: IEEE Standard Requirements for Capacitor Switches for AC Systems (1kV thru 38kV).

IEEE C37.90: IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus

IEEE C37.90.1: IEEE Standard for Surge Withstand capability (SWC) Tests for Relay and Relay Systems Associated with Electric Power Apparatus.

IEEE C37.90.2: IEEE Standard for Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE C37.90.3: IEEE Standard Electrostatic Discharge Tests for Protective Relays

IEEE C37.95: IEEE Guide for Protective Relaying of Utility-Consumer Interconnections

IEEE C37.102: IEEE Guide for AC Generator Protection

IEEE C62.41: IEEE Recommended Practice on Surge Voltages in Low-Voltage AC Power Circuits

LPC: Design Standards and Construction Specifications, Section 700.

NERC PRC-024-1: Generator Frequency and Voltage Protective Relays

NFPA 70: National Electrical Code

UL 1741: Inverters, Converters, Controllers, and Interconnection System Equipment for use with Distributed Energy Resources

3.2 Acronyms

ANSI	American National Standards Institute
DER	Distributed Energy Resource
DML	Daytime Minimum Load
EPS	Electric Power System
IEEE	Institute of Electrical and Electronics Engineers
kVA	Kilovolt Amperes
kW	Kilowatt
kWh	Kilowatt-hour
LPC	Longmont Power & Communications
MVA	Megavolt Amperes
NEC	National Electrical Code
NEMA	National Electrical Manufacturers Association

NERC	North American Electric Reliability Corporation
NESC	National Electrical Safety Code
NFPA	National Fire Protection Association
NRTL	Nationally Recognized Testing Laboratory
PCC	Point of Common Coupling
PoC	Point of Connection
PV	Photovoltaic
TRD	Total Rated Current Distortion
UL	Underwriters Laboratories
VAR	Volt-Amperes Reactive

3.3 Definitions

For the purposes of this document, the following terms and definitions apply.

AC: Alternating current.

Applicant: A person or entity that applies to interconnect DER with the LPC distribution system.

Area Electric Power System (Area EPS): Electric power system owned and operated by the utility, also known as the LPC distribution system.

Cease to Energize: Terminate active power generation and limit reactive power exchange. A momentary cessation may occur if abnormal voltage and/or frequency conditions return to acceptable levels within required time limits and the DER restores output. A cease to energize condition may also precede a trip.

Clearing Time: The time between the start of the abnormal condition and the DER ceasing to energize the Area EPS. It is the sum of the detection time, any time delay, and operating time and arcing time of the interrupting device(s) used to interconnect the DER with the Area EPS.

Continuous Operation: Exchange of current between the DER and an EPS within prescribed behavior while connected to the Area EPS and while the system voltage and frequency is within specified parameters.

Customer: Any person or entity that has an active account with LPC.

Daytime Minimum Load: The annual minimum load recorded on a feeder between the hours of 7 AM and 7 PM.

Distributed Energy Resource: A source of electric power, including both generators and energy storage technologies, capable of exporting active power to an EPS. An interconnection

system or a supplemental DER device that is necessary for compliance with this standard is part of a DER.

Distributed Energy Resource Unit: An individual DER device inside a group of DER that collectively form a system.

Electric Power System (EPS): Facilities that deliver electric power to a load.

Enter Service: Begin operation of the DER with an energized Area EPS.

Front of the Meter: DER that is directly connected to the Area EPS.

Generation: The production of electric energy or the release of stored electric energy from an energy storage system.

Interconnection: The physical connection of DER to the Area EPS.

Islanding: A condition in which a portion of an Area EPS is energized solely by one or more local EPSs through the associated PCCs while that portion of the Area EPS is electrically separated from the rest of the Area EPS on all phases to which the DER is connected.

Local Electric Power System (Local EPS): Electric power system contained entirely within a single premise or group of premises that is not owned or operated by the utility.

LPC Distribution System: Electric power system owned and operated by the utility, also known as the Area EPS.

Mandatory Operation: Required continuance of active current and reactive current exchange of DER with Area EPS as prescribed, notwithstanding disturbances of the Area EPS voltage or frequency having magnitude and duration severity within defined limits.

Operator: DER owner, successors, heirs, agents, employees, and assigns who are responsible for operating and maintaining the DER.

Permissive Operation: Operating mode where the DER performs ride-through either in mandatory operation or in momentary cessation, in response to a disturbance of the system voltages or frequency.

Point of Common Coupling (PCC): The point of connection between the Area EPS and the Local EPS, equivalent in most cases to “service point” as specified in the NEC.

Point of Connection (PoC): The point where a DER is electrically connected in a Local EPS.

Production Meter: Utility-provided meter used to measure the total energy output of a DER prior to any load consumption.

Utility Revenue Meter: Utility-provided bi-directional electric meter used to measure the energy consumed by customer loads and the net excess energy supplied from customer generation to the utility.

Restore Output: Return operation of the DER to the state prior to the abnormal excursion of voltage or frequency that resulted in a ride-through operation of the DER.

Return to Service: Enter service following recovery from a trip.

Ride-Through: Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.

Trip: Inhibition of immediate return to service.

15: Speed or Frequency matching function: This relay function will match and hold the speed or frequency of a machine or system equal to that of another machine, source, or system.

25: Synchronizing or synchronism check function: This relay function operates to close a breaker when two AC sources are within the desired limits of frequency, phase angle, and voltage to permit or cause the paralleling of the two sources.

27: Undervoltage function: This relay function operates when its input voltage is less than a predetermined value and will initiate a trip signal to the interconnection breaker(s).

32: Directional Power Relay/Reverse Power function: This relay function operates on a desired value of real power flow (watts) in a given direction and will initiate a trip signal once the reverse power setting is exceeded.

46: Reverse-Phase or Phase-Balance Current Relay/Negative Sequence Overcurrent function: This relay function operates when the phase currents are of reverse phase sequence, are unbalanced, or contain negative sequence components that exceed a preset value.

47: Phase-Sequence or Phase-Balance Voltage Relay/Negative Sequence Overvoltage function: This relay function is used to determine phase sequence and loss-of-phase.

50: Instantaneous overcurrent function: This relay function operates instantaneously on an excessive value of phase current.

50G/50N: Instantaneous ground/neutral overcurrent function: This relay function operates instantaneously on an excessive value of ground/neutral current.

51: Inverse time overcurrent function (often integral to the interconnection breaker): This relay function uses either definite or inverse time characteristics to monitor AC phase current values.

51G/51N: Inverse time ground/neutral overcurrent function: This relay function uses either definite or inverse time characteristics to monitor AC ground/neutral current values.

59: Overvoltage function: This relay function operates when its input voltage is more than a predetermined value and will initiate a trip signal to the interconnection breaker(s).

67: Directional overcurrent function: This relay function is intended to operate for a fault on the Area EPS and trip the interconnection breaker.

67G/67N: Directional ground/neutral overcurrent function: This relay function operates on a desired value of AC overcurrent flowing in a predetermined direction.

81O/U: Over/under frequency function: The function operates for specified variances from the normal system frequency.

4 DER Equipment and Installation Requirements

4.1 General Requirements

The installation of any DER must meet the relevant requirements of the National Electrical Code (NEC) and the National Electrical Safety Code (NESC). Where required by the municipality, the Operator cleared to move forward with the installation must obtain all necessary building permits, pass all applicable building department inspections, and meet other applicable requirements including, but not limited to, the Longmont Municipal Code and LPC's Design Standards and Construction Specifications.

Unless otherwise modified in this document, the interconnection must meet the requirements of IEEE 1547. Where the requirements of this document vary from the requirements of IEEE 1547, this document governs.

The Operator must be solely responsible for protecting the DER and all associated equipment from abnormal LPC distribution system conditions, such as outages, short circuits, voltage and frequency variations, and other disturbances. LPC will not install equipment for the protection of the DER or other equipment.

The DER equipment must be designed and operated so that it is capable of properly synchronizing the DER to the LPC distribution system, maintaining safe operation of the generation equipment, detecting any unusual operating condition, and disconnecting the DER from the LPC distribution system anytime damage to the DER or other equipment may occur. The equipment protection provided by the Operator must prevent the DER from adversely affecting the LPC distribution system's capability to provide reliable service to LPC customers.

The Operator is responsible for furnishing and installing required labeling on DER equipment and facilities in accordance with NEC and other applicable safety regulations. All labels must be permanently affixed at their respective locations.

No DER equipment used in the DER system shall be manufactured by any company on the United States Bureau of Industry and Security's Entity List (Supplement No 4 to Part 744)

4.2 DER Tap Connections

DER are permitted by the NEC to be connected, or tapped, on either the load (customer) side or the supply (utility) side of the of the customer's main service disconnecting means. All DER tap connections are subject to applicable NEC requirements, the requirements of the LPC's Design Standards and Construction Specifications, and the requirements of this document.

4.2.1 Load Side Tap

A load side tap is defined as a connection made after the customer's main service disconnecting means. A load side tap must be fed from a circuit breaker in the customer's electrical panel.

4.2.2 Supply Side Tap

A supply side tap, also known as a line side tap, is defined as a connection to the conductors after the LPC billing meter and before the customer's main disconnecting means.

A fused disconnect switch is required on all supply side tap connections and must meet all the requirements in section 4.3 Utility AC Disconnect Switch.

Supply side taps must be made in accordance with equipment manufacturer's instructions and NEC requirements including use of service rated materials listed for the application and adherence to enclosure fill requirements. Details of the supply side tap, including specification sheets of connection materials, must be submitted to LPC with the initial DER application.

Any modifications made to factory installed and/or listed equipment must be made in accordance with manufacturer's instructions, or the modification must be evaluated for the application by the equipment manufacturer or a Nationally Recognized Testing Laboratory (NRTL). If an equipment modification authorization is granted, proof of such authorization must be submitted to LPC with the initial DER application and a field label from the manufacturer or NRTL must be applied to the modified equipment.

No customer connections or equipment are permitted within LPC sealed meter equipment including sockets, compartments, pull sections, CT cabinets, etc.

Customers must schedule with LPC to de-energize their electric service conductors prior to performing a supply side connection, all applicable fees and schedule timelines for a service disconnect/reconnect will apply. Any removal of utility seals or metering equipment by the customer or electrician will be considered tampering and may result in criminal prosecution.

4.3 Utility AC Disconnect Switch

Each DER installation must include a manually operated, lockable in the open position, disconnect switch with a visible break for line clearances. The visible break must be viewable without unbolting covers or assistance from site personnel.

The utility disconnect switch must be externally mounted, located within 10 feet of the LPC utility revenue meter and must be located on the AC side of the DER such that the entire DER can be isolated from the LPC distribution system.

The disconnect switch must always be accessible by LPC personnel to allow the DER to be disconnected safely during maintenance or outage conditions. The disconnect switch must be rated to interrupt the maximum output of the DER, must be rated for the voltage and fault current requirements of the DER, and must meet all applicable NEMA, UL, ANSI, IEEE, and NEC standards as well as local and state electrical codes.

If the site contains more than one DER unit or system (e.g., PV and battery), a single disconnect switch may be used provided its rating is sufficient for all DER and opening it produces a visible break point between all DER and the LPC distribution system.

If more than one disconnect switch is used, each must meet the requirements in this section, be located within 10 feet of the LPC utility revenue meter and be labeled to clearly indicate multiple disconnects are used to isolate the DER at the site.

The disconnect switch must be permanently labeled, in accordance with NFPA 70 standards, with text indicating that the switch is for the DER. The labeling must also clearly indicate the open and closed position of the switch.

4.4 Transformer

The transformer supplied (whether supplied by LPC or Operator) to interconnect a three-phase DER to the LPC distribution system is required to be a grounded-wye to grounded-wye transformer.

Any three-phase step-up or step-down transformer connected in the DER installation must be a grounded-wye to grounded-wye connection.

DER will not be permitted to interconnect through transformer banks made up of two or more single phase transformers.

4.5 Dedicated Transformer and Additional Primary Protection

Any inverter-based DER over 50 kVA may be required to be connected to the LPC distribution system by a dedicated transformer, pending the results of an engineering analysis.

Most interconnecting transformers on the LPC distribution system are protected with fuses. However, if a DER is rated at 1000 kVA or above, LPC may determine the fuse protection is insufficient to properly protect the LPC distribution system. In this case, LPC may require a dedicated, three-phase interrupting device be added to the transformer high-voltage side along with necessary relaying.

A synchronous generator of any size may need to be connected to the LPC distribution system by a dedicated transformer, pending the results of an engineering analysis.

4.6 Interruption Devices

Circuit breakers or other interrupting devices located at the Point of Common Coupling (PCC) must be certified or “Listed” (as defined in Article 100, the Definitions Section of the National Electrical Code) as suitable for their intended application. This includes being capable of interrupting the maximum available fault current expected at their location. The Operator’s DER and associated interconnection equipment must be designed so that the failure of any single device will not compromise the safety and reliability of LPC’s distribution system.

4.7 System Protective Functions

The protective functions and requirements contained in this document are designed to protect LPC’s distribution system and not specifically the Operator’s DER. The Operator is solely responsible for providing adequate protection for the DER and all associated equipment. The Operator’s protective devices must not impact the operation of other protective devices utilized on the LPC distribution system in a manner that would affect LPC's ability to provide reliable service to its customers.

The DER’s protective functions must sense abnormal conditions and disconnect the DER from the LPC distribution system when those abnormal conditions occur. All DER must be capable of sensing three phase, line-line, and line-ground faults, and loss of source voltage on one,

two, or all three phases of the LPC distribution feeder interconnected to the DER. In any of the above abnormal conditions, the DER must disconnect from the LPC distribution system to protect both the line and the DER from damage due to excessive currents or unusual voltages.

The minimum protective functions and other requirements for system protection for various categories and sizes of DER are shown below. Unless otherwise specified, each DER must be protected by an electronic relay and must coordinate protection with LPC upstream protective devices. When required, DER Operators must submit all relay settings and test reports to LPC for review and LPC will determine whether an on-site inspection is required to observe calibration and testing of the relay and/or inverter functions. All relays must be utility grade (must meet IEEE Std. C37.90, C37.91, C37.92, and C37.93) and must be independent from the generator control devices.

Any DER system that is not included in one of the following categories must be individually considered by LPC.

Table 4-1 - Minimum Protection Functions for Category A1

Category A1	ANSI Standard Minimum Protective Functions
Less than 100 kVA	25, 27, 47, 50[1], 50G[1], 51[1], 51G[1], 59, 81O, 81U
100 kVA to 999 kVA[2]	25, 27, 32, 47, 50G, 50V, 51G, 51V, 59, 81O, 81U
Greater than1000 kVA[2]	25, 27, 32, 40, 46, 47, 50G, 50V, 51G, 51V, 59, 81O, 81U

[1] DER less than 100kVA may include overcurrent trip functions (50/51) in a breaker trip unit or fuse.

[2] All interrupting devices for DER of 100 kVA or greater, must be 3-phase circuit breakers with electrical operation.

- A function to prevent the DER from contributing to the formation of an unintended island and to prevent the DER from reconnecting with LPC's distribution system under abnormal conditions is required.

Table 4-2 - Minimum Protection Functions for Category B2, Inverter Based

Category B2, Inverter Based	ANSI Standard Minimum Protective Functions
Less than 1000 kVA	50[1], 51[1]
Greater than 1000 kVA	27[2], 50[1], 51[1], 50G[1], 51G[1], 59[2], 81O[2], 81U[2]

[1] Overcurrent trip functions (50/51) may be in a breaker trip unit or fuse.

[2] Protective device must be separate from the inverter control system and internal disconnect device

- Inverters must be tested and conform to the latest versions and supplements of IEEE 1547 and UL1741.

- If the inverter does not carry a UL sticker, DER Operator must supply LPC with certification from a NRTL stating the inverter has been tested to and meets the above IEEE and UL standards.

Table 4-3 - Minimum Protection Function for Category B2, Non-inverter Based

Category B2, Non-Inverter Based	ANSI Standard Minimum Protective Functions
Less than 100 kVA	15[1], 27, 47, 50[2], 50G[2], 51[2], 51G[2]
Greater than 100 kVA[3]	15[1], 27, 32, 46, 47, 50[2], 50G[2], 51[2], 51G[2], 81O, 81U

[1] Automatic speed matching to within 5% prior to closing associated breaker.

[2] Overcurrent trip functions (50/51) may be in a breaker trip unit or fuse.

[3] All interrupting devices for DER of 100 kVA or greater, must be 3-phase circuit breakers with electrical operation.

- If the generator is capable of self-excitation, the DER must include functions to:
  - prevent contributing to the formation of an unintended island
  - prevent reconnecting with LPC's distribution system under abnormal conditions.
- If the generator is incapable of self-excitation:
  - DER Operator must provide documentation of such to LPC indicating that anti-islanding protection is not required. If such documentation does not meet LPC approval, anti-islanding protection will be required.

4.8 Momentary Paralleling Power Systems

Some backup power systems operate parallel to the LPC distribution system only momentarily (normally less than 0.1 second). With LPC's approval, the transfer switch or system used to transfer the Operator's loads between LPC's distribution system and the Operator's DER may be used in lieu of the protective functions required for parallel operation. In this scenario, all transfer schemes and electrical drawings must be provided to LPC for review and LPC will determine if an on-site inspection is required to observe and verify the functionality of the transfer switch or system.

5 Facility Grounding

The DER grounding system must not adversely impact LPC grounding or ground fault protective relaying. The DER grounding must not cause high voltages to occur under any condition, either during normal operating conditions or during a LPC distribution system fault (e.g., single-line-to-ground fault). The DER must not be designed or implemented such that the earth becomes the sole fault current path.

5.1 Surge Protection

The DER Operator is responsible for providing surge or transient protection of the DER equipment.

5.2 System Grounding

LPC maintains an effectively grounded LPC distribution system and requires that all DER be designed to contribute to an effectively grounded system. Effective grounding prevents the

occurrence of excessively high voltages during ground faults and protects existing LPC equipment. Effective grounding of the DER may desensitize existing LPC ground fault protection, which could require LPC ground fault relay setting changes or modifications in the design of the DER.

Single-phase inverter-based DER falling within Class 1 or Class 1R are typically excluded from this requirement.

The transformer supplied to interconnect three-phase DER to the LPC distribution system will normally be a grounded-wye to grounded-wye transformer. This connection will not provide a grounding source by itself and will not provide an effectively grounded system from the DER side of the interconnection unless effective grounding of DER is implemented. When designing the grounding system for the DER, the designer should consider the condition that will result when a ground fault occurs on the line serving the DER. This ground fault would be cleared on the LPC side of the line by opening a substation breaker or a downstream interrupter or fuse. This will result in momentarily islanding the line on the DER until it trips. Under this condition, where the line is islanded and being supplied by the DER, the system must remain effectively grounded.

5.2.1 Grounding of Rotating Machine Generators

Rotating machine generators listed in Category A1 and Category B2 must comply with effective grounding as defined by IEEE 142, which states that to be considered effectively grounded both of the following two conditions must be met:

1) The ratio of zero-sequence reactance to positive-sequence reactance (X0/X1) must be positive and three or less.

2) The ratio of zero-sequence resistance to positive-sequence reactance (R0/X1) must be positive and less than 1.

The DER equivalent (Thevenin equivalent) impedance must meet the criteria for effective grounding stated above. The networks used in determining this impedance, and other fault current calculations for the plant, will include the positive, negative, and zero sequence networks of the step-up transformer connected to the LPC distribution system, all other transformers between the DER and the point of common coupling, the DER subtransient, positive, negative and zero sequence values, the neutral grounding device for the DER, the grounding transformer and neutral grounding device (if used) and any significant cable runs. The DER must maintain an effectively grounded system under normal operating conditions while operating connected to the LPC distribution system.

The short circuit contribution ratio (SCCR) of the DER is defined as the ratio of the DER short circuit contribution to LPC's contribution to a short circuit (ISC_{DER}/ISC_{LPC}) for either a three-phase or single-line- to-ground fault measured at the high voltage side of the transformer stepping up from the generation voltage to the LPC voltage.

The DER must be grounded in such a way that the SCCR for a line-ground fault calculated at the high voltage side of the transformer connecting the DER to LPC is less than 3% while still achieving effective grounding as defined above. If this SCCR ratio is greater than 3% LPC must do a study to determine if re-setting ground fault relays on the existing LPC distribution system is required. In rare cases connecting a certain DER to a particular feeder may not be practical due to protection issues or special protection techniques may be needed to make the

connection safe.

Proper grounding of the DER can be achieved in several ways. LPC may, at its discretion, accept any of the following methods:

a) Solidly grounding the DER or installing a solidly grounded grounding transformer (zigzag or grounded wye-delta transformer). While a solidly grounded DER is acceptable to LPC if all other requirements are met, it must be used with care. ANSI standards generally require that for a synchronous generator the ground fault current must be limited to the three-phase fault current. This usually requires a resistance or reactance be used for grounding the DER neutral. Also, a solidly grounded DER may conduct large amounts of harmonic currents. There may be some unbalanced voltage at the terminals of the DER. This can cause circulating current through the DER system if it is solidly grounded which may make de-rating of the DER necessary. If a solidly grounded system is used the designer must consider and plan for all issues that may result.

b) Resistance grounding. A resistance grounded DER or grounding transformer with a resistance placed between neutral and ground may be used if it meets the requirements of effective grounding.

c) Reactance grounding. A reactance grounded DER or grounding transformer with a reactor between the transformer neutral and ground may be used if it meets the requirements of effective grounding.

d) Other methods may be suggested for consideration by LPC.

5.3 DER Connection at LPC Primary Voltage

If the Applicant desires to generate at the LPC primary voltage and to connect the DER directly to the LPC distribution system without the use of an interconnecting transformer, a study of the connection is required. The study, conducted by LPC or their designated subcontractor, will determine the grounding and other requirements necessary for this type of connection. The Applicant is responsible for the cost of the study as outlined in section 2 above.

6 DER Operation

The Operator must not operate the DER in any way that causes a system disturbance or that imposes a voltage or current upon LPC's distribution system that interferes with safe LPC operations, service to LPC's customers, or other LPC equipment and facilities.

When LPC suspects that interference with electric service to other LPC customers is occurring, and such interference exceeds LPC Standards, LPC reserves the right, at its expense, to install test equipment as may be required to perform a disturbance analysis and monitor the operation of the DER to evaluate the quality of power produced. If the DER is demonstrated to be the source of the interference, and it is demonstrated that the interference produced exceeds LPC Standards or generally accepted industry standards, LPC may, without liability, disconnect the DER from the LPC distribution system to ultimately confirm the DER is the source of the disturbance. Once confirmed, it must be the responsibility of the Operator to eliminate any interference caused by the DER and the Operator must diligently pursue and take corrective action, at the Operator's own expense, to eliminate undesirable interference caused by the

DER. The DER will be reconnected to the LPC distribution system only after the Operator demonstrates to the satisfaction of LPC that the cause of the interference has been remedied.

The Operator's protective devices must prevent the DER from contributing to an island. If the portion of the LPC distribution system the DER is connected to becomes islanded for any reason, the DER must detect the island, cease to energize, and trip in accordance with the most current IEEE 1547 requirements.

Three-phase DER must be able to detect an open-phase condition, cease to energize, and trip in accordance with the most current IEEE 1547 requirements.

DER are not permitted to enter service or return to service until LPC distribution system conditions have been maintained within the normal range for a minimum of five (5) minutes.

6.1 Voltage Regulation

The DER must not actively regulate the voltage at the point of common coupling (PCC) unless the effects of this are first reviewed and approved by LPC. If LPC determines it is advantageous for a DER to actively control its voltage, LPC will inform the Operator and the Operator will be required to control the DER's terminal voltage.

6.2 System Voltage

The voltage operating range limits for DER must be used as a protection function that responds to abnormal conditions on LPC's distribution system. The LPC voltage operating range is normally 95% to 105% of the nominal voltage at the PCC, and 90% to 105% of nominal voltage at the utilization point, as required by ANSI C84.1 Range A. Occasional excursions outside this range may occur, and the DER must respond as required in this section.

6.2.1 Mandatory Trip Voltage Limits

In accordance with IEEE 1547, when the voltage at the PCC is above the Over Voltage (OV) limits or below the Under Voltage (UV) limits in this section, the DER shall cease to energize and trip within the clearing time indicated.

6.2.2 Ride Through Voltage Requirements

Voltage ride through requirements are not applicable if frequency is greater than 62 Hz or less than 57 Hz.

Ride-through requirements are not applicable if either of the following conditions are satisfied:

a) The net active power exported across the PCC into the Area EPS is continuously maintained at a value less than 10% of the aggregate rating of the DER connected to the Local EPS prior to any voltage disturbance, and the Local EPS disconnects from the Area EPS, along with the Local EPS load to intentionally form a Local EPS island.

b) An active power demand of the Local EPS load equal or greater than 90% of the pre-disturbance aggregate DER active power output is shed within 0.1s of when the DER ceases to energize the Area EPS and trips.

6.3 System Frequency

The DER shall operate in synchronism with the LPC distribution system. Whenever LPC's distribution system frequency at the PCC varies from nominal (60 Hertz) by the amounts as set forth in Table 5, the DER's protective functions shall disconnect the DER from the LPC distribution system with delay times no longer than those shown.

Unless some other anti-islanding scheme is employed, the DER shall disconnect due to low frequency resulting from islanding the feeder load on the DER. The frequency settings must be adjusted to ensure that, during the lowest loading level on the feeder, the resulting frequency change of the DER when it is islanded with those feeder loads, should cause the under-frequency protection to disconnect the DER within two seconds.

6.3.1 Mandatory Trip Frequency Limits

In accordance with IEEE 1547, when the frequency at the PCC is above the Over Frequency (OF) limits or below the Under Frequency (UF) limits, the DER shall cease to energize and trip within the clearing time indicated.

6.3.2 Ride Through Frequency Requirements

Frequency ride-through requirements are not applicable if voltage is outside of voltage ride-through ranges specified in IEEE 1547. Ride-through requirements are not applicable if either of the following conditions are satisfied:

a) The net active power exported across the PCC into the Area EPS is continuously maintained at a value less than 10% of the aggregate rating of DER connected to the Local EPS prior to any frequency disturbance, and the Local EPS disconnects from the Area EPS, along with Local EPS load to intentionally form a Local EPS island.

b) An active power demand of the Local EPS load equal or greater than 90% of the pre-disturbance aggregate DER active power output is shed within 0.1s of when the DER ceases to energize the Area EPS and trips.

6.4 Synchronization

Synchronous machine automatic synchronizers and sync-check relays shall be set in accordance with IEEE 1547.

6.5 Voltage Fluctuations and Light Flicker

Any voltage fluctuations at the PCC caused by the DER shall not exceed the limits defined by the "Maximum Borderline of Irritation Curve" identified in IEEE 519, IEEE 141, and IEEE 1453. This limit is shown in Figure 1. This requirement is necessary to minimize the adverse voltage effects that may be experienced by other customers on the LPC distribution system due to the operation of the DER. Induction generators may only be connected to the LPC distribution system and brought up to synchronous speed (as an induction motor) if these limits are not exceeded.

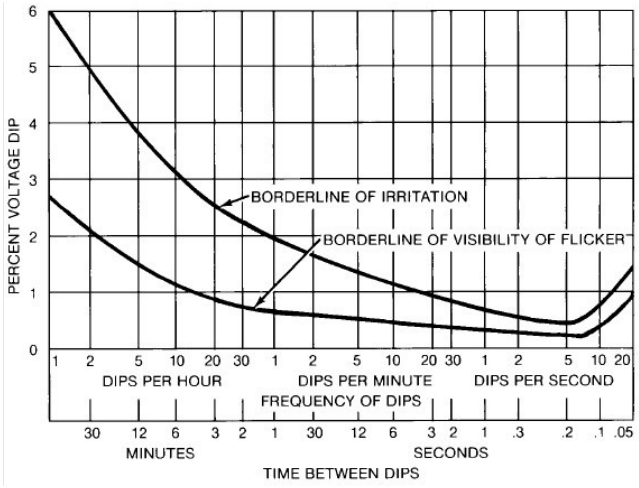

Figure 6-1 - Allowable Voltage Fluctuations vs. Time
(Reproduced from IEEE 141)

6.6 Harmonics

Harmonic distortion measured at the PCC must comply with IEEE 519 and IEEE 1547. DER shall not inject direct current greater than 0.5% of the full rated output current into the LPC distribution system.

6.7 Power Factor

The power factor at the PCC shall always remain within 0.95 lagging (VARs consumed by the site) to 0.95 leading (VARs supplied by the site) unless otherwise approved by LPC.

Inverter-connected DER must be set to operate in a constant power factor mode with a power factor of 1. LPC may require modifications to the power factor settings described in this section if it is determined to be beneficial to the LPC distribution system. Required settings will be quantified in a written agreement between LPC and the DER Owner/Operator.

Synchronous generators shall be capable of operating at any point within a power factor range of 0.95 leading (i.e., VARs absorbed by generator, capacitive, -0.95) to 0.95 lagging (i.e., VARs supplied by the generator, inductive, +0.95). Synchronous generators should automatically control power factor and should be set to deliver VARs to the system as needed to keep the power factor at the PCC within the range required by this section.

For non-inverter generators other than synchronous generators, operation outside this power factor range is acceptable provided the cumulative power factor of the customer's entire facility, measured at the PCC, is kept within the range noted.

This may be done using capacitor banks, adding static VAR compensators (SVC) or synchronous condensers, or other means agreeable to both the DER and LPC. If capacitor banks are used, they shall be sized and installed per IEEE Standards. 18, 1036, C37.012, C37.06, C37.66, and 1015. Capacitors may need to be stepped and switched to meet the power factor requirements above. Before the addition of capacitors, the Operator should completely study the effects of the capacitor additions on the resonance conditions and harmonic values that will result. The Operator will provide the study results to LPC for review. If the addition of

capacitors causes adverse resonance or harmonics effects on LPC's distribution system, the Operator shall be required to pay for any modifications needed to mitigate the problem.

6.8 Disconnect Switch Operation

LPC operational procedures require line crews to create a visible break in the circuit between themselves and all potential sources of generation when working on deenergized equipment. The visible break disconnect switch may be used for this purpose during both planned outage work and unplanned outage restoration.

Under no circumstances shall the Operator tamper with or attempt to close a disconnect switch that has been opened and locked out/tagged out by LPC personnel.

7 Metering, Interoperability, and Security Provisions

The following metering, telemetry, and security provisions must be met by any Operator connecting a DER to the LPC distribution system.

7.1 Metering

Unless otherwise required by a feed-in tariff rate scenario, shared energy system installation, or by a stipulation in a customer's interconnection agreement, LPC will install, own, and maintain a kilowatt-hour meter or meters, as LPC may determine, capable of registering the bi-directional flow of power and energy at the PCC.

DER falling within Class 2 & 3 size classifications will require separate metering of DER production. At its sole discretion, LPC may require separate metering of production on any DER interconnected to the LPC distribution system. This metering will record all generation produced and may be billed separately from any bi-directional metering or customer usage metering.

LPC will install, own, and maintain the production meter, other costs associated with the production metering, including the meter socket, meter socket installation and wiring, will be paid by the customer. The production meter must be located within 10 feet of the main LPC billing meter.

All utility installed meters will be 'advanced meters' that may measure and transmit such parameters as time of delivery, power factor, voltage profile, load profile and other information as deemed necessary by LPC.

All DER installations, including primary metered DER installations, must meet the requirements contained within LPC's Design Standards and Construction Specifications.

The use of meter collar adapters is not permitted.

7.2 Interoperability

As DER integration increases, there will be a greater need for data exchange between LPC and the DER. Access and real time continuous connection at the request of LPC may become a condition of operation to maintain the interconnection to the LPC distribution system.

Such data may include:

- nameplate information – provides the as-built characteristics of the DER
- configuration information – provides the present capacity and ability of the DER to perform functions which may change based upon static or dynamic conditions
- monitoring information - provides the present operating conditions of the DER including system status, system output, and active functions
- management information – provides ability to update, enable, and disable functional and mode settings of the DER

The communication requirements, as well as to what type and size of DER systems they apply, will continue to evolve as DER installations increase in both system size, number, and functionality and industry standards develop.

DER certified to IEEE 1547and UL 1741, have the capability to provide grid support functions, such as volt/VAR, volt/watt, and other interoperability features. All non-mandatory grid support features must be disabled. If grid support is needed in the future, required settings will be quantified in a written agreement between LPC and the DER Owner/Operator.

In addition, DER are required to have a dedicated communications port for LPC use for monitoring and control of DER as more advanced grid management systems are introduced.

These communication requirements apply to connected DER with a capacity of 100 kVA or larger aggregated at the PCC, however the applicable system size and communication methods are subject to change at any time at the sole discretion of LPC. In all cases, the Operator must be required, at the direction of LPC, to operate and maintain equipment that will be used for monitoring and control of the facility.

The Operator will be responsible for all hardware, software, and any installation costs associated with the DER installation. The communication system must be designed to allow LPC to perform the following:

- Trip the DER system breaker for unstable system conditions, such as frequency, voltage, and fault conditions
- Place a **hotline tag** on the DER breaker relay that would block the breaker's closing circuit to prevent operation
- Allow for future power dispatching by LPC through utility control system, which may include constraint and/or curtailment of DER output
- Real time monitoring of the following data points:
    - Active (Real) power
    - Reactive power
    - Current on each phase

- Neutral current
- Voltage
- Frequency
- Operational state
- Connection status
- Alarm status
- Operational state of charge for storage systems
- Solar irradiance for PV systems (W/m^2)
- System breaker or operation status to determine if the system is on or offline
- Others as required by LPC

The Operator must provide all the necessary interface design to accomplish the functions listed above. The Operator must submit drawings of the proposed design to LPC for review and approval.

7.3 Cyber Security

Cyber security is a growing concern in all aspects of industry. LPC cyber security requirements will be evolving and changes in security for monitoring and control can be expected. The nature of the information and the communications method will drive the type and level of security employed. Larger DER will require increased cyber security measures due to the potential impact on the LPC distribution system and the need for more extensive monitoring and control.

8 Testing

8.1 Commissioning Tests

The following inspections and tests are required by LPC before operation of DER in Class 2 and 3 system size classifications. At its sole discretion, LPC may require inspection and testing of Class 1 size DER systems.:

- Visual inspection of distribution transformer
- Visual inspection of the DER
- Visual inspection of the disconnect switches
- Visual inspection of the breaker
- Visual inspection of the fuses
- Operation test of the disconnect switch

- Phasing test
- Sync test
- Phase loss test
- Phase absent test
- Anti-islanding test
- Power quality test

The Operator must notify LPC 2 weeks in advance of the time of the testing so that LPC representatives may observe the tests required by LPC. If the phase loss or phase absent testing is required, LPC will schedule a line crew to perform the switching on the LPC distribution system.

Prior to performing the commissioning tests, the installation is required to be inspected and approved by City of Longmont Building Services.

8.2 Periodic Maintenance Tests and Inspections

LPC reserves the right to inspect any DER equipment interconnected to the LPC distribution system.

An Operator must maintain the DER equipment in good order and in compliance with all manufacturer's suggested periodic maintenance. If it is discovered that an Operator is not properly maintaining the equipment, LPC may disconnect the DER until such time that the Operator can prove that they have provided all required maintenance needed to allow the DER to operate properly and safely.

For all DER consisting of synchronous machines with aggregate ratings of larger than 1,000 kVA, no less than once every 3 years all protective functions must be re-tested and calibrated to prove their operation complies with the requirements contained in this document. The Operator must maintain written records of these tests and these records must be made available to LPC on request.

Battery systems used for DER control or protective relaying must be maintained and periodically tested as suggested by the battery manufacturer.

8.3 Qualified Personnel

All testing and calibration must be done by qualified personnel licensed with the City of Longmont.

8.4 Permission to Operate

City of Longmont Building Inspection will notify LPC once the DER installation is complete and has passed inspection.

LPC will set the bi-directional meter and perform commissioning testing as outlined above.

Once the meter is set, LPC will send permission to operate (PTO) documentation to the customer email listed on the Interconnection Agreement. DER System Modifications

After the DER begins operation, any design changes, such as the addition of more generation capacity, must be submitted to LPC for review and may require modification of an existing Interconnection Agreement. Protective devices or any other requirements listed in this document must not be modified or their settings changed without approval of LPC.

9 Liability and Insurance

In no event must LPC be held responsible for the safety, reliability, design, or protection of the DER. Compliance with these interconnection standards does not mean the DER is safe to operate, and the Operator is solely responsible for deciding whether the DER is safe to operate.

Nothing herein must be construed to create any duty to, any standard of care with reference to, or any liability to any person who is not a party to an arrangement or agreement between LPC and the Operator pursuant to these requirements.

LPC is not liable for damages caused to the facilities, improvements, or equipment of the Operator by reason of the operation, faulty operation, or non- operation of LPC facilities.

To the extent permitted by law, the Operator must be solely responsible for and must defend, indemnify and hold LPC harmless from and against any and all claims or causes of action for personal injury, death, property damage, loss or violation of governmental laws, regulations or orders, which injury, death, damage, loss or violations occurs on or is caused by operation of equipment or facilities on the Operator’s side of the point of connection.

Notwithstanding the above and to the extent permitted by law, the Operator must be solely responsible for and must defend, indemnify and hold harmless LPC and the City of Longmont from and against any and all claims or causes of action for personal injury, death, property damage or loss or violation of governmental laws, regulations or orders, wherever occurring, which injury, death, damage, loss or violation is due solely to the acts of omissions of such Operator, including but not limited to the use of defective equipment or faulty installation or maintenance or equipment by such party.

However, nothing contained in this section must be construed as relieving or releasing either party from liability or personal injury, death, property damage or loss, or violation of governmental laws, regulations, or orders, wherever occurring, resulting from its own negligence or the negligence of any of its officers, servants, agents, or employees.

In the event of concurrent negligence, liability must be apportioned between the parties according to each party’s respective fault. Neither the Operator nor LPC must be liable to the other or any other third party, in contract or in tort or otherwise, for loss of use of equipment and related expenses, expense involving cost of capital, claims of customers of LPC or the Operator, as applicable, loss of profits or revenues, cost of purchase or replacement power, or any indirect, incidental, or consequential loss or damage whatsoever.

The Operator must pay all costs that may be incurred by LPC in enforcing the indemnity described herein. Each party’s liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney’s fees, relating to, or arising from any act or

omission in its performance of this agreement, must be limited to the amount of direct damage actually incurred. In no event must either party be liable to the other party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever.

9.1 Insurance Requirements

For systems 50 kVA and up to but not including 500 kVA and larger, the Operator, at its own expense, except when the Operator is a governmental entity that self-insures in accordance with Colorado law, must secure and maintain in effect during connection of its DER to the LPC distribution system, liability insurance with a combined single limit for bodily injury and property damage of not less than $1,000,000 each occurrence.

For systems of 500 kVA and up to but not including 1,000 kVA, the Operator, at its own expense, except when the Operator is a governmental entity that self-insures in accordance with Colorado law, must secure and maintain in effect during connection of its DER to the LPC distribution system, liability insurance with a combined single limit for bodily injury and property damage of not less than $2,000,000 for each occurrence.

Insurance coverage for systems greater than 1,000 kVA must be determined on a case-by-case basis by LPC and will reflect the size of the installation and the potential for system damage.

Operators are also required to secure and maintain in effect during connection of its DER to the LPC distribution system, automobile insurance with a minimum liability limit of not less than $1,000,000 and Worker's Compensation insurance at the statutory limits.

Such insurance must not exclude coverage for any incident related to the subject DER or its operation. Except when the Operator is a governmental entity that self-insures in accordance with Colorado law, the City, its officers, agents, and employees must be named as an additional interest under the liability policy.

Any insurance policy required herein must include that written notice be given to LPC at least 30 days prior to any cancellation or reduction of any coverage. Such liability insurance must provide, by endorsement to the policy, that LPC must not by reason of its inclusion as an additional interest incur liability to the insurance carrier for the payment of premium of such insurance.

A copy of the liability insurance certificate must be received by LPC prior to DER operation. Certificates of insurance evidencing the requisite coverage and provision(s) must be furnished to LPC prior to date of interconnection of the DER. LPC must be permitted to periodically obtain proof of current insurance coverage from the Operator to verify proper liability insurance coverage. The Operator will not be allowed to commence or continue interconnected operations unless evidence is provided that satisfactory insurance coverage is in effect.

10 Variance and Appeals

10.1 Variance from LPC Interconnection Standards

Whenever there are practical difficulties involved in carrying out the requirements described in this document, the LPC Director of Electric Services or their designee, has the authority to grant modifications for individual cases, upon written request of the Applicant, provided LPC Staff review finds that the proposed design plan is in compliance with the intent and purpose

of the LPC Interconnection Standards and that such modification does not lessen health, accessibility, life and fire safety, or reliability. The details of actions granting or denying modification requests must be recorded and entered in LPC's department files or records management system(s).

10.2 Appeals

The LPC Director of Electric Services or their designee, is authorized to hear and decide appeals of decisions made by the Staff review relative to the Variance request and interpretation of the requirements contained within the LPC Interconnection Standards.

When an Applicant desires relief from a requirement within this document, such Applicant must first apply for a modification under Section 10.1 above and receive a notice of decision on that request from the LPC.

If, after receiving a modification decision, an Applicant desires to seek further relief, such Applicant may appeal the subject modification decision to the LPC Director of Electric Services stating that such decision was based on erroneous interpretation of the requirements contained in the LPC Interconnection Standards. Such appeal must be filed in writing with the LPC Director of Electric Services within 10 days of the Applicant's receipt of notice that Staff has denied the Applicant's modification request.

The LPC Director of Electric Services is authorized to rule in favor of the Applicant when they determine that the interpretation of the applicable requirements was erroneous or when they determine an alternative design or plan is equivalent to the requirements prescribed considering effectiveness, fire resistance, durability, safety, health, and reliability.