TRANSMISSION & DISTRIBUTION

INTERCONNECTION REQUIREMENTS

FOR

GENERATION

May 15, 2022

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CENTRAL MAINE POWER

REVISION HISTORY

This document replaces Central Maine Power's (CMP) "Interconnection Requirements for Generation" dated March 19, 1998, as well as all earlier versions of CMP's Technical Interconnection Requirements.

The most current version of this document is available electronically at www.cmpco.com, Suppliers and Partners -> Regulatory Information -> CMP Transmission Services.

Document Revision	**Date**	**Reason for Revision**
Technical Interconnection Requirements for Non-Utility Generation	December 30, 1994	Superseded previous Documents
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CENTRAL MAINE POWER COMPANY
TRANSMISSION AND DISTRIBUTION
INTERCONNECTION REQUIREMENTS
FOR GENERATION

i. Purpose - The purpose of this document is to establish the Technical Interconnection Requirements for Generation to connect to Central Maine Power Company's Transmission & Distribution (T & D) system. Central Maine Power Company will also be referred to as the Company and on occasion, the Interconnecting Transmission Owner (ITO). This document reflects, in part, the Company's view of Prudent Electrical Practices with respect to the installation of generation interconnection equipment. These requirements are written to establish a basis for maintaining power quality, system reliability and a safe environment for the general public, power consumers, maintenance personnel, and equipment. This document describes the general protection requirements for parallel operation and includes typical one-line diagrams. This document also includes equipment maintenance requirements and details the information that must be provided to the Company during all stages of a project. **This document is a guide and as such, is not intended to be used as the sole basis for the specific design of the Generator's protection systems and interconnection with the T&D system.** Additional technical requirements for interconnection are contained in the Independent System Operator New England (ISO-NE) Open Access Transmission Tariff (OATT), ISO-NE Planning Procedures, ISO-NE Operating Procedures, the Northeast Power Coordinating Council (NPCC) Criteria documents, the North American Electric Reliability Corporation (NERC) reliability standards, and Inverter Source Requirement Document of ISO New England (ISO-NE). **Final design will be subject to Company review and approval on a case-by-case basis.**

These Interconnection Requirements are intended to be consistent with Schedules 22 and 23 of the ISO-NE Open Access Transmission Tariff (OATT), State of Maine Chapters 313, 315, and 324. To the extent there are any conflicts between this document and a site-specific Interconnection Agreement, or Schedules 22 and 23 of the ISO-NE OATT, as may be amended from time to time, the Interconnection Agreement or the OATT will be the controlling document.

Please be advised that intertie interconnection for all distribution projects that are not subject to FERC Jurisdiction are covered under the MPUC Chapter 324 rules and requirements. Please see website www.MPUC.gov or www.cmpco.com.

ii. Use

This document is intended for general use by existing and prospective Generator and Company personnel.

iii. Definitions

Generator – refers to a developer or non-utility owner and/or operator of generation and generation facilities interconnecting or interconnected to the Company's EPS.

Distribution System – refers to 34.5 kV, 19.9 kV, 12.47 kV, 7.2 kV, and 4.16 kV distribution circuits and associated interconnection facilities to the Transmission System. Distribution systems can be operated as single, two, or three phase systems.

Electric Power System (EPS) – refers to the Company's Transmission and Distribution (T&D) System and associated equipment. The term T&D system may be used interchangeably with EPS throughout this document.

Interconnection Facility – refers to the Generator facilities necessary to effect the transfer of electricity to the Point of Interconnection.

Qualified Company Personnel – refer to those persons employed by the Company having the required knowledge, training, experience, and accountability in specialized areas of Transmission Services, Transmission & Distribution Engineering, and Transmission & Distribution Planning.

Point of Interconnection (POI) – refers to the point where the Interconnection Facilities connect with the Company's EPS. The terms Demarcation Point (DP) and Point of Common Coupling (PCC) are used interchangeably with POI throughout this document.

Transmission System – refers to the Company's electrical system which includes 345 kV, 115 kV, 69 kV, and 34.5 kV transmission sections. The transmission system is always operated as a three phase power system to move power throughout the interconnected transmission system. All interconnections to this system shall be three phase. The transmission system is considered FERC jurisdictional.

iv. Interconnecting Generator Responsibility

The interconnection requirements set forth herein are intended to describe the Company's process and requirements for electrically connecting generation that will operate in parallel to the Company's EPS. Other non-electric utilities (such as cable and telephone utilities) may be involved in the interconnection process. The costs of these other utility services shall be borne by the Generator interconnecting to the Company's EPS. It is the responsibility of the interconnecting Generator to contact these other utilities and to arrange for the provision of any necessary services from such utilities and the payment of charges imposed by such utilities.

v. Interconnecting Generator Safety

The Company is committed to operating in a manner that protects the safety and health of our employees and the public. The safe delivery of the Company's services to the public is paramount. Safety is a primary concern in all interconnection projects. The Company urges Generators, Generator employees, contractors and subcontractors to utilize the utmost care in working near or around any of the Company's equipment, energized lines and substation(s). All independent contractors working at or near the Company's EPS shall comply with all Federal and State safety regulations.

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I. General Information

The information in this interconnection requirements document is supplied to Generators for the purpose of establishing and maintaining an acceptable interconnection with the Company's Transmission & Distribution (T&D) system. Safety, reliability, and power quality are of utmost importance and, as such, careful study of each proposed installation and the identification of appropriate interconnection requirements is necessary before a Generator's facility is allowed to begin interconnected operation. This standard is based on the Company's requirements as well as the requirements of the Maine Public Utilities Commission (MPUC), the Regional Transmission Organization or Independent System Operator (RTO or ISO), the Northeast Power Coordinating Council (NPCC), the North American Electric Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC), or other authorities having jurisdiction. ISO New England, Inc. (ISO-NE) is the RTO for New England.

Any Generator desiring interconnection with the EPS or modification of an existing interconnection must meet the specifications set forth in this document and any other requirements which may be imposed by the Company, including without limitation:

- the latest approved version of the IEEE 1547 (Standard for Interconnecting Distributed Resources with Electric Power Systems) and associated 1547 standard and family of guidelines or recommended practices;
- the latest approved version of UL (Underwriters Laboratories) 1741 (Inverters, Converters, Controllers and Interconnection System Equipment for use with Distributed Energy Resources); and
- the latest approved version of UL 1741 SA (Supplement A).

A. Application Process for Interconnections

Before a Generator submits an interconnection request to interconnect a new generating facility or modify an existing facility, the Generator must determine whether the project will be interconnecting to the ISO-administered transmission system under the ISO's process or interconnecting through the state process.

The Company's Interconnection process per Chapter 324, contains a pre-application process whereby the Company will generate a pre-application report providing applicants information about system conditions at a proposed point of interconnection.

Chapter 324 in its entirety can be found at the following location:
https://www.maine.gov/sos/cec/rules/65/chaps65.htm

The Company's interconnection process can be found at the following location:
https://www.cmpco.com
Smart Energy -> Innovation-> Interconnection

ISO-NE's interconnection process can be found at the following location:
https://www.iso-ne.com/participate/applications-status-changes/interconnection-process-guide

B. Review & Approval

FERC jurisdictional generators in New England (and therefore in Maine on the Company's electrical system) must comply with the ISO-NE FERC Electric Tariff No. 3, referred to as the Open Access Transmission Tariff (OATT). This Tariff contains the requirements for applying for a new generator interconnection or changing an existing generation facility.

Documents that control the level of ISO-NE involvement in non-FERC jurisdictional interconnection processes such as the MPUC's Chapter 324 include but may not be limited to the following.

- Section I.3.9 of the ISO-NE Tariff
- ISO-NE Planning Procedure (PP) 5-0
- ISO-NE PP 5-1
- ISO-NE PP 5-3
- ISO-NE PP 5-6
- Schedule 22 of the ISO-NE Tariff "Large Generator Interconnection Procedures"
- Schedule 23 of the ISO-NE Tariff "Small Generator Interconnection Procedures"
- ISO-NE Operating Procedure No. 14 (OP-14) "Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources"
- ISO-NE Operating Procedure No. 18 (OP-18) "Metering and Telemetering Criteria"

In general, any project over 1,000 kW requires compliance with Section I.3.9 and participation in the PP 5-1 process.

OP-14 defines other requirements for generation, depending on their classification with ISO-NE such as requirements to register as a defined Generator, submit PSS/E dynamics models, maintain telemetry equipment defined by OP-18, maintain a 24x7 Designated Entity for dispatch services, and provide voltage regulation through an automatic voltage regulator.

1. Interconnection Request

The Generator, to the extent required in Schedules 22 and 23 of the ISO-NE OATT, shall submit a completed Interconnection Request to the System Operator, ISO New England Inc., together with the processing fee or deposit specified in the Interconnection Request. These requests can be found on the ISO-NE website located at www.iso-ne.com. From the main web page, go to Participate, New or Modified Interconnections, and then choose either the Small Generator Interconnection Request Form (less than or equal to 20 MW) or the Large Generator Interconnection Request Form (greater than 20 MW). After the Request is submitted, ISO-NE, in consultation with the Company, will determine whether the interconnection request is complete and the Generator will be notified to arrange a scoping meeting.

For Generators connecting to the non-FERC jurisdictional Distribution System, the Generator shall submit an application to the Company, together with the application fee pursuant to Chapter 324.

Interconnections Levels per Chapter 324 are as follows.

Level	Criteria
Level 1	Inverter-Based Generators Not Greater than 25 kW & Meeting Screens for Level 1
Level 2	Generators Not Greater than 2 MW & Meeting Screens for Level 2
Level 3	Non-Exporting Generators Not Greater than 10 MW & Meeting Screens for Level 3
Level 4	All Generators Not Meeting Levels 1, 2, or 3 and Not Subject to FERC Jurisdiction

2. Interconnection Studies

In general, all requests for a new generation interconnection or a material modification to an existing generating facility will require one or more interconnection studies. Interconnection study options include Feasibility Study, System Impact Study, and/or Facilities Study. Either ISO-NE or the Company will process the interconnection request/application, arrange for a scoping meeting, and prepare an interconnection study agreement. The Generator will provide any necessary upfront deposits.

A supplemental study may be required if one or more system impact study criteria are violated and cannot be resolved with the Company's standard construction practices or standard equipment. The Generator shall be responsible for all costs and expenses associated with a supplemental study. For example, if an interconnection screening fails due to voltage flicker, it might be necessary to perform an additional time series analysis outside of the impact study.

The interconnection study process will result in a final report that will determine the feasibility and/or system impact to the EPS and identify any required system enhancements.

3. Interconnection Costs

Unless otherwise specified in a site-specific interconnection agreement, or the ISO-NE OATT, the Generator will pay the interconnection costs for any system enhancements required by the Company to allow connection to the EPS. This will include the costs of new transmission or distribution facilities and/or upgrades to existing facilities, metering equipment, and changes to the Company's protection system. The Company will require prepayment for any necessary work.

With regard to any interconnection costs or ongoing charges, if there are any conflicts between these interconnection requirements and a site-specific interconnection agreement, or the ISO-NE OATT, as may be amended from time to time, the interconnection agreement or the applicable transmission tariff will be the controlling document.

4. Design Approval

The final decision on the design of new facilities or modifications to existing facilities required to meet the interconnection request will be based upon ISO-NE and the Company's design standards. The interconnection requirements or upgrades will be identified in the study documents (including Feasibility Study, System Impact Study and Facility Study) and incorporated into the Interconnection Agreement (IA). The Company will review and provide written approval for the facility's design which is required to meet these interconnection requirements.

5. Initial Inspection and Testing

Prior to the initial synchronization to the EPS, the interconnection facilities must be inspected, calibrated, and functionally tested. **The Company will inspect the interconnection facilities and will either perform or observe the functional testing.** Refer to Sections III.L, "Generator Facility Acceptance," and III.M, "Synchronizing to the T&D System," for more specific information on this process.

6. Ongoing Testing and Maintenance

After the initial synchronization, the Generator is required to perform periodic testing and maintenance of the interconnection facilities to ensure this equipment will operate properly. Section VII.E, "Testing & Maintenance," provides additional details for these ongoing requirements.

C. Operation and Maintenance Charges

Equipment, including the Generator, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Generator or the Company. The Company will provide a best estimate itemized cost, including overheads, of its Interconnection Facilities and metering equipment, and a best estimate itemized cost of the annual operation and maintenance expenses associated with its Interconnection Facilities and metering equipment.

D. Grandfathering

Generators already connected to the EPS are not exempt from the requirements of this document. The Company's Interconnection Requirements are periodically revised to reflect changes in standard electrical practice and the EPS. Each Generator's facility will be subject to review as a result of analyzing local EPS problems as well as during the initial inspection and ongoing biennial test and inspections. The Company may require reasonable modifications to the Intertie Protection System as a result of these reviews and inspections.

E. Generators 1,000 kW and Larger

All facilities that have a generating capacity of 1,000 kW or greater must be equipped with SCADA equipment (as described in Chapter V, "Supervisory Control and Data Acquisition") and, for manned facilities, a telephone line dedicated to voice communications for Energy Control Center purposes. For unmanned facilities, the Generator must provide an alternative means of communications for Energy Control Center purposes.

For Generators greater than or equal to 5,000 kW, ISO-NE and the Company require the unit to be explicitly modeled. This means there an equivalent generator step-up unit (GSU) (and separate equivalent park transformer if installed), equivalent generator, and equivalent line with equivalent collector/feeder impedance must be provided. This should be provided in a ready-to-use RAW data file.

The Generator is required to provide a short circuit model for use with ASPEN software for each generator with a gross output of 5,000 kW or greater. Inverter-based generators should be modeled as voltage-controlled current sources (VCCS).

The Generator is required to provide detailed dynamic models for each generator with a gross output of 5,000 kW or greater. These models will be provided in Siemens PSS/E format. The model must be from the list of NERC approved models and not a user-defined model. Other detailed modeling requirements, such as PSCAD model, may be required as determined by ISO-NE or on a case-by-case basis.

F. Facilities Connected to the Bulk Power System

Generation facilities that are either directly connected to the Bulk Power System (BPS) or which may have a potential impact on the BPS must also comply with ISO-NE Inc., NPCC, NERC, and AVANGRID's Transmission and Distribution Planning manuals, guides, requirements and standards, and this document. The classification of BPS facilities is determined by test according to NPCC A-10 Criteria. NPCC maintains a complete listing of BPS facilities within their jurisdiction.

G. Facilities Connected to the Bulk Electric System

Interconnection Facilities that are either directly connected to the Bulk Electric System (BES) or that may have a potential impact on the BES must comply with the NERC Reliability Standards (FAC-002 and others); ISO-NE procedures; and AVANGRID's Transmission and Distribution Planning Manuals, guides, requirements, and standards; and this document. The classification of BES facilities is determined by test according to the NERC BES Definition. ISO-NE maintains a complete listing of BES facilities within their jurisdiction.

H. Facilities Connected to the Non-BPS System

Interconnection facilities connected to the Non-BPS and Non-BES transmission system, including ISO-NE Pool Transmission Facilities (PTF), the Company's local transmission system (Non-PTF) and the Company's distribution system, must comply with the ISO-NE Planning Procedures, AVANGRID's Transmission and Distribution planning manuals, and this document, as applicable.

I. DC & Variable Speed Generators

Direct current generators and variable speed alternating current generators may be connected to the EPS through a synchronous inverter. The inverter installation will be designed such that an EPS interruption will result in the removal of the generator/inverter from the EPS. Synchronous inverters must comply with the Company's power quality requirements as outlined in Section II.F, "Power Quality."

J. Generators 25 kW and Less

Generation equipment up to 25 kW may be installed, where appropriate power lines exist, without an extensive engineering review. However, the Generator must install the appropriate protection and obtain written approval from Qualified Company Personnel, as specified in this document, before commencing interconnected operation.

K. Emergency Generators

Emergency generators cannot be connected to, or operated in parallel with, the EPS, except for momentary paralleling (paralleling for 0.5 seconds or less). Facilities may utilize momentary paralleling of emergency generators providing they use automatic controls to monitor and control the switching process. The automatic control and switching system WILL require Company review and approval. These facilities do not require an Intertie Protection System to monitor for faults on the EPS. For additional information on emergency generators see the Company's Contractor's Handbook for Electrical Service and Meter Installations.

L. Generators 50 MW and Greater

Generators 50 MW and greater are required to have a Dedicated ARD (Auto Ring Down) phone to the Company's Energy Control Center.

II. General Requirements

The Generator's installation shall meet all requirements of prudent electrical practices, methods, and standards that are commonly used in engineering and plant operations and maintenance to provide for a safe, reliable and dependable installation.

In addition to meeting those practices, methods, and standards and the requirements set forth in this document, as may be changed from time to time, the Generator's equipment and installation shall conform to the latest revision of the National Electrical Safety Code (NESC), the National Electrical Code (NEC), and all other applicable Federal, State, and Local Government codes. These include American National Standards Institute (ANSI), Institute of Electrical and Electronics Engineers (IEEE), National Electrical Manufacturers Association (NEMA), Occupational Safety and Health Administration (OSHA), Environmental Protection Agency (EPA), Maine Department of Environmental Protection (MDEP), NERC, FERC, NPCC, and ISO-NE codes and standards, and comply with all mandated compliance standards.

A. Interconnection Process and Required Information

To facilitate the interconnection process, the Generator should contact the Company and/or ISO-NE early on in the design stages of the proposed installation. The Generator must provide the Company the following information on each proposed facility:

- Complete, accurate, and applicable data to enable the proper modeling of the Generator's unit in load flow, transient stability, and fault studies. This will include line, transformer, and machine data as well as parameters for exciter systems, governor systems, and power system stabilizers. All dynamic data must be provided in Siemens PSS/E format compatible with the versions from 33 to the most current software versions.
- Design data and specifications which reflect the facility's reactive capability.
- All information regarding design and implementation of any proposed Special Protection System(s) associated with its facilities.
- Unit availability data including both unit design data and known performance data from other facilities utilizing similar equipment.

Figure II at the end of this chapter provides Electrical Equipment Data Sheets that the Generator must complete and forward to the Company for the Company to perform an engineering study. Upon receipt of the required information, as part of the engineering study, the Company will review the Intertie Protection System requirements. Any additional requirements not explicitly specified in this document will be provided by the Company to the Generator. The Generator must submit design documents reflecting these additional requirements to the Company for review and approval.

B. Protection System Requirements

Each Generator must design, install, maintain, and operate appropriate protection systems. The Generator must obtain the Company approval of specific relays and intertie equipment before parallel operation can begin. Section III, "System Protection," covers the Company's requirements for the protection systems in greater detail.

C. Transformer Interface

In general, the Generator's facility shall interface with the EPS through a step-up transformer or bank of transformers of adequate kVA rating and proper voltage rating for conversion from the facility's generator voltage to utility distribution or transmission voltage. The ratio of this step-up transformer must not restrict the reactive capability requirement specified in Section G, "Reactive Power (Power Factor)," below. This step-up transformer must meet the technical requirements specified in Section III, B - "Transformer Connections."

D. Switching Equipment and Station Ground

Each installation must be provided with the following switching equipment and station ground:

1. POI Disconnect Switch

For Distribution System interconnections, the Generator will be responsible for the cost of a manual, three-phase, gang-operated, visible, lockable, interrupter switch at the point of connection to the EPS. This switch will be located on the utility side of the POI. This switch will be owned and operated by the Company.

For Transmission System interconnections, the Generator will provide an isolation device as approved by the Company at the point of connection to the EPS. CMP reserves the right as to ownership of this switch.

See Section VI, "Safety," for switch operation requirements. The DP or POI switch name will be assigned by the Company and that name will be used in all facility documentation, communication, and switching between the facility and the Company. Facilities with generation capacity of 100 kW or less may have this requirement waived as long as the requirement D.2, below, is met.

2. High-Side Interrupting Device

The high side of the facility's step-up transformer must be connected to the EPS through a high-side breaker, recloser, or fuse. This device must be capable of interrupting both the facility's full generation capacity and the maximum fault current at this location.

3. Device Naming Convention

It is strongly recommended for consistency and clear communication that the High Side Interrupting Device and all devices between it and the DP switch be named following the convention assigned to the DP. Therefore, the identification, location, and naming of all devices between the High Side Interrupting Device and the DP switch should be done early in a project to avoid the need for changes to drawings and documentation.

4. Station Ground

The facility's station ground must be designed and installed in accordance with Company substation standards and the NESC.

E. Generator Circuit Breakers

A circuit breaker is normally required between each generator and the facility step-up transformer. This breaker provides a means to disconnect the generator from the EPS under fault conditions as well as providing a means to synchronize to the EPS. Under certain conditions, it may be more economical to design this device into the high-voltage side of the step-up transformer. If this is the case, a low-side disconnect device will still be required.

F. Power Quality

The Maine Public Utilities Commission has established certain criteria for the Company to meet in order for all power consumers to be served in a manner consistent with expected power quality standards. The following criteria are established to ensure that generation facilities within the utility service area provide the power quality expected by power consumers and other generators.

1. Voltage

The Generator shall not cause the voltage at any point along the EPS to deviate from the levels of +/-5% of nominal as specified by MPUC Chapter 320 and ANSI C84.1 Range A.

Voltage limits for generation facilities connected to the EPS will be determined by the Company. Any facility with synchronous generators may be required to provide voltage support to the EPS by operating their generator at any point within the Generator's capability curve as directed by Energy Control Center.

2. Step Voltage Change and Flicker

- Voltage flicker emission and/or rapid voltage changes caused by step changes at generating facility must be less than 3% for individual facilities and less 5% of the nominal voltage for part or all of the Generator facilities on a feeder. This can also be evaluated using IEEE 1453.
- Aggregate Generator voltage fluctuation shall not result in a voltage change of greater than half the bandwidth of any voltage regulating devices on the associated feeder.

3. Harmonics

The harmonic content of the voltage and current waveforms on the EPS must be restricted to levels which will not cause any interference or equipment operating problems for customers. Minimum requirements for limitations of harmonic content on the EPS shall comply with IEEE Standard 519 and IEEE 1547.

Under no circumstances may the harmonic current distortion, originating from the Generator be greater than the values listed in Tables 3 and 6 from IEEE 1547.

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

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

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

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

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

Harmonic problems will also be addressed on a complaint basis. If the Company determines that the Generator’s facility is the cause of a harmonic problem, then that generation must be removed from the EPS until the condition is resolved. In addition, all costs associated with research and corrective action, including settlements paid to other customers, will be at the Generator's expense.

4. Islanded Generation Limits

Unintentional islanding by the Generator of all or part of the EPS (meaning a part of the EPS is kept energized by the generating facility after the EPS has de-energized the area) is prohibited as it may result in unsafe conditions on the EPS.

Under certain circumstances, the Company may request that the Generator serve local distribution load while isolated from the EPS. To accommodate these situations, the voltage and frequency limits will be specified by the Company. These will be reviewed and approved by the Company on a case-by-case basis.

G. Reactive Power (Power Factor)

Generators other than Induction Generators may be required to operate within a power factor range of 0.95 leading to 0.95 lagging within ±5 percent of rated voltage at the POI. Unless specifically determined through studies performed by the Company and as may be specified in the Interconnection Agreement, the power factor as measured at the PCC shall be within such range. The method and compensation for power factor correction shall be determined by the Company. Generators may be required to operate in either power factor or voltage control mode as directed by the ISO-NE or the Company to assist in maintaining normal and emergency system voltage schedules. Generators must maintain operating limits or interconnection service may be discontinued.

The nominal rating of the step-up transformer’s high voltage winding will be specified by the Company to ensure the EPS reactive power requirements are met. As a minimum, the step-up transformer will be provided with No Load Tap Changer (NLTC) settings that span ±5 percent of the nominal voltage at 2½ percent intervals.

Taps on any station service transformers within the Generator’s facility will also be set such that the Generator’s system will support this reactive capability requirement. If tap settings restrict the Generator’s reactive capability, the transformers must be replaced. The cost for such replacement will be the responsibility of the Generator.

H. Routine Maintenance

As a minimum requirement, each Generator is expected to adopt an Operations and Maintenance program consistent with the Operations and Maintenance section of this document. Maintenance records will be kept on file at the Generator’s facility and will be provided to the Company upon request.

I. Capacitors

The Company must maintain a near unity power factor at its substations. If a Generator facility is required to operate at a non-unity power factor, the Company may need to install one or more capacitor banks in or near the distribution substation to supply the Generator facility's reactive power consumption, at the Generator's cost, in order to ensure meeting the Company's power factor obligations. The capacitor banks would be owned and operated by the Company. The Generator will be responsible for the initial installation cost as well as maintenance costs going forward.

J. Phase Unbalance

There may be single-phase fuses or automatic line switching devices, installed between the utility power source and the generator, which may operate and cause phase unbalance. It is the sole responsibility of the Generator to protect their own equipment from any such unbalance. The Company will not assume any responsibility or liability for this protection.

K. Insulation and Insulation Coordination

Essential to the stable operation of the transmission system is proper coordination of the system's insulation strength. Internal insulation of equipment and external insulation of transmission lines and substation buses is required. Basic Lightning Impulse Level (BIL) for the Company conforms to the most recent version of IEEE Standard 1313 for Transmission voltages at 34.5 kV, 115 kV, and 345 kV as noted.

L. Electrical System Parameters

DESCRIPTION	VALUE
Frequency	60 Hertz
System Parameters – 345 kV System	
Nominal Voltage	345 kV Line to Line
Maximum Design Level Voltage	362 kV
Basic Impulse Level	1300 kV
Design Continuous Amperage (S NOR)	*See Section 3.6*
Interrupting Device Rating	50 kAIC
Bus Bracing/ equipment withstand rating	42 kA
Grounding	Solidly grounded
System Parameters – 115 kV System	
Nominal Voltage	115 kV Line to Line
Maximum Design Level Voltage	121 kV
Basic Impulse Level	550 kV
Design Continuous Amperage (S NOR)	*See Section 3.6*
Interrupting Device Rating	42 kAIC
Bus Bracing/ equipment withstand rating	32 kA
Grounding	Solidly grounded
Capacitors, rated kV for normal power out	115 kV
System Parameters – 34.5 kV System	
Nominal Voltage	34.5 kV Line to Line

Maximum Design Level Voltage	38.0 kV
Basic Impulse Level	200 kV
Design Continuous Amperage (S NOR)	*See Section 3.6*
Interrupting Device Rating	42 kAIC
Bus Bracing/ equipment withstand rating	32 kA
Grounding	Solidly grounded
Capacitors, rated kV for normal power out	34.5 kV
System Parameters – 12.47 kV System	
Nominal Voltage	12.47 Line to Line
Maximum Design Level Voltage	
Basic Impulse Level	95 kV
Design Continuous Amperage (S NOR)	600 A
Interrupting Device Rating	10 kA
Bus Bracing/ equipment withstand rating	
Grounding	$0<X_0/X_1<3$; $R_0/X_1<1$
Capacitors, rated kV for normal power out	12.47 kV
System Parameters – Station Service	
Nominal DC Voltage	125

M. Changes

The EPS is dynamic and must be able to accommodate future load growth and system changes. Therefore, the Company may, at its discretion and cost, make upgrades to the EPS. Such upgrades may have an impact on existing Generator facilities and/or interconnection facilities. To ensure continued safe operations in compliance with the Interconnection Agreement, the Generator facilities and/or interconnection facilities may need to be upgraded in accordance with the upgraded EPS. The Generator and the EDC will work together and cooperatively to implement the appropriate changes, upgrades, etc. to attain the common goal of continued safe and reliable operation of the interconnection of the Generator to the EPS.

In general, the Generator must receive written authorization from the Company and potentially ISO-NE before making any changes to a Generator facility that may have a material impact on the safety or reliability of the company's EPS.

Any additions, modifications, or replacements shall be done in accordance with Good Utility Practice and shall be designed, constructed, and operated in accordance with applicable standards, interconnection agreements, manuals, and guidelines.

1. Modification of Small Generating Facilities; Generators No Larger Than 20 MW

The Generator must receive written authorization from: the Company and potentially ISO-NE before making any changes to the small Generator facility that may have a material impact on the safety or reliability of Company's EPS or ISO-NE's reliability of the New England Transmission System. Modifications shall be done in accordance with Good Utility Practice. If the Generator makes such modification without ISO-NE's or the Company's, as appropriate, prior written authorization, the latter shall have the right to temporarily disconnect the small Generator facility.

2. Modification of the Large Generating Facilities; Generators that Exceed 20 MW

Either the Generator or the Company may undertake modifications to its facilities. If either plans to undertake a modification that reasonably may be expected to affect the other's facilities or the New England Transmission System, that party shall provide to the others and any affected party sufficient information regarding such modification so that the other party(ies) may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Generator. The party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other party (ies) at least ninety (90) Calendar Days in advance of the commencement of the work. Notwithstanding the foregoing, no party shall be obligated to proceed with a modification that would constitute a Material Modification or an Interconnection Request under the large generator interconnection process, except as provided under and pursuant to the large generator interconnection process.

In the case of large Generator facility modifications that do not require a Generator to submit an interconnection request, the Company shall provide, within thirty (30) Calendar Days, an estimate of any additional modifications to the New England Transmission System, the Company's interconnection facilities or network upgrades necessitated by such Generator modification and a good faith estimate of the costs thereof.

N. Company Disclaimer

The Company's review of the Generator's facility, equipment, interconnection equipment, protective devices, and metering does not confirm or endorse the design. The Company's review is not a warranty of safety, durability or reliability of the facility or any of the equipment. The Company shall not, by reason of such review or failure to review, be responsible for strength, safety, details of design, adequacy or capacity of the Generator's facility, equipment, interconnection equipment, or protection systems. **The Company will not assume any responsibility or liability for protection of the Generator's electrical system resulting from interconnected operation of a Generator's facility with the EPS.**

O. Additional Requirements for Inverter-Based Installations

Additional standards are applicable to inverter-based technologies. Two external standards shall apply to inverter-based Interconnections: (1) IEEE Standard 1547, (Standard for Interconnecting Distributed Resources with Electric Power Systems): and (2) UL Standard 1741 and UL Standard 1741 SA, "Inverters, Converters, Controllers and Interconnection System Equipment for use with Distributed Energy Resources." These standards set forth the nominal voltage and frequency parameters that must be met and the limits allowed for anomalies such as flicker and interference, as well as the time allowed for disconnection when the required parameters are no longer being met or for reconnection following a system failure or automatic disconnection.

The Company recognizes the concept of "Type Certification" (sometimes called pre-certification) which requires that the inverter-based units undergo standardized testing, usually by an Accredited Nationally Recognized Testing Laboratory (e.g., Underwriter's Laboratory), and that the results of those tests be made publicly available. Type certified units typically must also be "listed" by the laboratory and the equipment labeled as such.

Advanced inverters also provide grid support functionality and can assist with resource availability in the event of a bulk power system or other disturbance.

1. The requirements of UL 1741/1741 SA may be applied to inverters with photovoltaic and other electric energy sources. An inverter is considered approved if it is certified to the UL 1741/1741 SA testing procedure and it has passed the required tests without failure to comply with IEEE C62.41 and C62.45. Proof of certification under UL1741/1741 SA and compliance with IEEE C62.41, and C62.45 shall be required. As of May 7, 2007, UL 1741 includes the requirements within it of IEEE C62.41, and C62.45. Therefore, equipment tested to UL 1741/1741 SA after that date need only prove compliance with UL 1741/1741 SA.

2. It is the Generator's responsibility to submit written evidence that the proposed Generating Facility has been UL 1741/1741 SA certified. Generators should contact the Generating Facility's supplier to determine if it has been listed.

3. Non-certified inverters must have either non-islanding or anti-islanding protection as defined by IEEE 1547 and conform to the maximum harmonic limits prescribed in IEEE 519. Noncertified inverters must be protected by certified or Utility-Grade Relays, using settings approved by the Company.

For all projects involving Energy Storage System (ESS), the Generator must submit a completed form as shown in Appendix 1 specifying the proposed ESS characteristics to the Company. The Company's technical review shall determine whether the proposed ESS facility, operating per the characteristics identified in the application, can be safely and reliably interconnected to the EPS.

Generation Interconnection Information –All

Customer/Company Name:____________
Project Name:_______________
Type of Generator:◯ Synchronous,◯ Wind,◯ Photovoltaic,◯ Fuel Cell,◯ Battery,◯ Other
Size of Generator/Project (MVA, MW):________
Proposed site address (Street number, town, state, zip):__________________________________
Latitude, longitude:_________________
Maps (Geographic, site)
Drawings (geographic, site, project)
Station service power requirements:___________
Connection voltage:_______
CMP circuit number and/or substation name of proposed connection:_______
Connection line data (R, X, length, line type (overhead, underground), wire size and type):
____
Generator capability curve

Intertie protection system data

Provide one line, three line, and DC elementary diagrams of the electrical design showing the following information:

1. Generator Step-Up Transformer (GSU) - Ratio, Rating & Winding Configuration.
2. Voltage Transformers (VTs) - Ratios, Ratings & Winding Configurations.
3. Current transformers (CTs) - Ratios & Ratings.
4. Protective Relays - Model and Style Numbers.
5. Switching Devices - Manufacturer's Electrical Specifications.
6. Trip and Close Circuits.
7. Synchronizing Devices - Generator Specifications

Site (and/or generator step up) transformer data

Transformer MVA Rating	________________________________
Transformer Voltage Rating	________________________________
Available Taps	________________________________
Connection of Windings (ie., Wye-Wye, Wye-Delta, etc.)	________________________________
Transformer Leakage Impedance's for Positive	_____________ p.u. on ___________ tap
and Zero Sequence on the transformer base	_____________ p.u. on ___________ tap
between each pair of windings and for each	_____________ p.u. on ___________ tap
available tap.(etc., as needed)	_____________ p.u. on ___________ tap
	_____________ p.u. on ___________ tap
	_____________ p.u. on ___________ tap
Type of Grounding *	________________________________
Neutral Impedance (Reactance/Resistance) *	________________________________

* Develop in conjunction with the Company.

Reactive device (Synchronous condenser, statcom, DVAR, switched shunt) data

Type:______
Manufacturer:________
Model:___
VAR capability (kVAR or MVA, specify):________________
Connection point:______________________
Capability curve
PSSE models will be determined by the Company
Other pertinent data

PSSE Modeling Data (version 33 to current version)

Steady state model and idv files
Bus number should be easily discernable from other system parameters. Bus numbers shall be six digits and above 990000.
PSSE Generic dynamic model (not user-defined) and dll and dyr files
Block diagrams of model, exciter, power system stabilizer, control modules

Rotating Generators

GENERATOR DATA

Required for sites > 1,000 kW

Preliminary _____ Final _____

Manufacturer	______________________
Generator Nameplate Number	______________________
Rated MVA at Rated H_2 psig	______________________
Rated kV	______________________
Rated P.F. (±)	______________________
Max. Turbine kW Capability (Utilizing over pressure, etc.)	______________________
Field Amperes for Rated Conditions	______________________
Field Amperes at Rated Generator Volts & Amps. @ 0 p.f. Overexcited	______________________
Field Resistance	__________ Ohms @ ______°C
Generator Grounding Type/Specification	______________________

		In Per Unit on Rated Machine MVA and kV
Direct Axis Unsaturated Synchronous Reactance	X_d	__________
Quadrature Axis Unsaturated Synchronous Reactance	X_q	__________
Direct Axis Transient Reactance at Rated Current	X'_{di}	__________
Direct Axis Transient Reactance at Rated Voltage	X'_{dv}	__________
Quadrature Axis Transient Reactance at Rated Current (where applicable)	X'_{qi}	__________
Direct Axis Subtransient Reactance at Rated Current	X''_{di}	__________
Quadrature Axis Subtransient Reactance at Rated Current	X''_{qi}	__________
Direct Axis Subtransient Reactance at Rated Voltage	X''_{dv}	__________
Quadrature Axis Subtransient Reactance at Rated Voltage	X''_{qv}	__________
Negative Sequence Reactance	X_2	__________
Zero Sequence Reactance	X_0	__________
Stator Leakage Reactance at Rated Voltage	X_{lv}	__________
Stator Leakage Reactance at Rated Current	X_{li}	__________
Potier Reactance	X_p	__________
Positive Sequence Resistance	R_1	_______ @ ______ °C
Zero Sequence Resistance	R_0	_______ @ ______ °C
Negative Sequence Resistance	R_2	_______ @ ______ °C
Direct Axis Transient Open-Circuit Time Constant	$T_{d'o}$	_____ sec. @ ____ °C
Direct Axis Subtransient Open-Circuit Time Constant	$T_{d''o}$	_____ sec. @ ____ °C
Quadrature Axis Transient Open-Circuit Time Constant (where applicable)	$T_{q'o}$	_____ sec. @ ____ °C
Short-Circuit Time Constant of Armature Winding	T_a	_____ sec. @ ____ °C
Generator, Turbine and Exciter Inertia	WR^2	____________ Lb. Ft.^{2}
Rated Speed		____________ R.P.M.
Inertia Constant on Machine Base	H_c	_______ Mw Sec./MVA
Saturation Curve No. on Open-Circuit		__________
Saturation Curve No. for Rated Stator Current at 0 pf lagging		__________
"V" Curve No. (Capacity Curve)		__________

The above resistances, reactances and time constants are defined in ASA Standards-Definitions of Electrical Terms (Group 10-Rotating Machinery, Section 31).

EXCITATION SYSTEM DATA

Required for sites > 1000 kW

Manufacturer	____________________				
Type of Excitation System **	IEEE Type 1 ________	2 ________	3 ________	4 ________	DC ________
					AC ________
					ST ________
Voltage Response	____________________				
Manufacturer Exciter Type	____________________				
Manufacturer Regulator Type	____________________				
Saturation Curve No. on Open Circuit	____________________				
Saturation Curve No. for Rated Armature Current	____________________				

* Develop in conjunction with the Company.

** Please supply gains, time constants and limits applicable to the model. IEEE Paper F 80 258-4, "IEEE Committee Report on Excitation System Models for Power System Stability Studies" provides model descriptions and block diagrams.

Driver data

Type:___________
Fuel:__________
Manufacturer:_____
Nameplate number:_____
Nameplate data:___________
Governor type:___
 Manufacturer:____
 Model:___

PSSE models

Generator:_____
Compensator:____
Stabilizer:________
Minimum excitation system:_____
Maximum excitation system:______
Excitation system:_________
Turbine – governor:__
Turbine load controller:_____
Any other pertinent models:_______________

Bus number should be easily discernable from other system parameters. Bus numbers shall be six digits and above 990000.

Wind Generators

Manufacturer:______
Model:____________
Number of generators:_____
Number of GSU: ________
Project Size (MVA/MW):__________
Type (1, 2, 3, 4, 5, other):____
Individual data
    MVA/MW:_________
    VAR capability:__________
Equivalent machine data
    MVA/MW:______
    VAR capability:__________
One-line diagram showing layout of the project

PSSE Models

Generic wind generator:_
Generic wind electrical:_______
Generic wind mechanical:_
Generic wind pitch controller:____
Generic wind aerodynamic controller:_
Generic wind auxiliary controller:____
Wind machine protection:__________
Any other pertinent models:_______________

Bus number should be easily discernable from other system parameters. Bus numbers shall be six digits and above 990000.

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Photovoltaic or Fuel Cell

◯ PV ◯ Fuel Cell

Panel or Fuel Cell

Manufacturer:______
Model:____________
Number of panels or cells:_____
Project size (MVA/MW):__________
Individual data
MVA/MW:_________
VAR capability:__________
Equivalent machine data
MVA/MW:______
VAR capability:__________
One-line diagram showing layout of the project

Inverter Data

Manufacturer:_____
Model:_____
Number of inverters:____
Output voltage:____

PSSE Models

PV Converter__________
PV Electrical Control Model __________
PANEL________
Any other pertinent models:_______________

Project modeling should be created using equivalent representation guidance from the WECC Guide for Representation of Photovoltaic Systems in Large-Scale Load Flow Simulations.
Bus number should be easily discernable from other system parameters. Bus numbers shall be six digits and above 990000.

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Battery or Other

◯ Battery◯ Other_________

Battery Project Data

Battery type(Lead-acid, NiCad,etc):_____________
Manufacturer:____
Model:_______
Amp-Hr:______
kwHr:__________
Number of batteries:______
Project size (MVA/MW):__________
Individual data
MVA/MW:_________
VAR capability:__________
Equivalent machine data
MVA/MW:______
VAR capability:__________
Max charging load:_____
Max output:__________

Charger Data

Manufacturer:_________
Model:___________
Nameplate:__________
Input voltage:________

Inverter data

Manufacturer:_________
Model:___________
Nameplate:__________
Output voltage:________

PSSE Models

EPRI Battery Energy Storage:____
Any other pertinent models:_______________
If a project is a Battery Energy Storage facility, a separate generator model with negative Pmax representing charging mode (with Qmax/Qmin at this negative Pmax) should be added to the RAW data file. Use generator ID “G” for the generation mode and “L” (load) for the charging mode.
Bus number should be easily discernable from other system parameters. Bus numbers shall be six digits and above 990000.

Other Type Project Data

Describe project. Data needed will be determined based on type of project.

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III. Protection Systems

Requirements for protection due to interconnected operation of generation facilities will vary depending on the size and type of installation and the characteristics of the EPS at the point of interconnection. The following requirements are necessary for planning and designing generation facilities for interconnected operation with the EPS.

A. Company Engineering Review of Proposed Generation Facilities

Only those portions of the drawings and other design documents which apply to the Interconnection Facilities and the Intertie Protection System, see Footnote 1, will be reviewed to determine if any changes are required due to the interconnected operation of the Generator's facility.

B. Transformer Connections

Generally, the step-up transformer high voltage winding must be connected in a grounded/wye configuration. The Generator will coordinate with the Company to select a transformer connection and grounding arrangement. The transformer connection and grounding arrangement should be such that zero-sequence current cannot pass through the transformer. A configuration that is not in-line with this requirement will require further studies to determine if it will be acceptable. For Distribution connected generation, the EPS must remain "effectively grounded" such that $X_0/X_1 \leq 3$ and $R_0/X_1 \leq 1$ so the voltage rise in the unfaulted phases does not exceed 125% of the nominal system line-to-ground voltage on the affected circuit(s).

C. General Protection System Descriptions

The Company Protection System and the Intertie Protection System must provide the necessary level of protection for the EPS. The Company will determine the Intertie Protection System relay settings and changes to the existing Company Protection System or other power system equipment due to the interconnected operation of the Generator's facility.

1. Intertie Protection System

The Intertie Protection System must detect power system faults or abnormal conditions and will not take into consideration protection for the Generator's electrical system or equipment; rather it will provide protection for the EPS and other customers. The Intertie Protection System will:

- comply with the minimum operating and safety standards set forth in these requirements and in Maine Public Utilities Commission Chapter 320 rules;
- operate to limit the severity and extent of system disturbances and damage to EPS equipment;
- detect abnormal operating conditions and disconnect the Generator’s facility when such conditions do not return to normal within certain time limits;
- communicate with utility equipment as required;

Footnote 1. The relay can protect the utility from having generators island on the system after the utility disconnects power from the feeder. This is accomplished by monitoring the intertie (point of common coupling to the utility) for abnormal voltage, abnormal frequency, and excessive power import/export, which can indicate loss of utility supply. The relay also provides detection of phase and ground faults, as well as current and voltage unbalance on the utility system.

- monitor for loss of the utility supply (feed) and prevent energizing a de-energized utility circuit, except when doing so as provided under Section VI.D, “Islanded Generation Limits;” and
- be located in a secure, environmentally controlled, easily maintained, and readily accessible location, such as a switchgear room.

2. Bulk Power System (BPS)

Any Generator whose facility is interconnected to the BPS will be required to meet Northeast Power Coordinating Council (NPCC) guidelines for protection requirements. These guidelines require redundant protection equipment including station batteries, breaker trip coils, station service AC supply, and breaker failure systems. The Company will verify these requirements are incorporated into BPS interconnected facilities.

3. Generator Protection System

Generators must provide the necessary Generator Protection System, see Footnote 2, to protect their own equipment. The Company will provide system data to the Generator to allow the Generator to coordinate their protective system settings with the Company’s Protection System and the Intertie Protection System.

In addition to these standard protection systems, the Company may require other Special Protection Systems at certain sites. Special Protection System requirements will be determined by the Company on a case-by-case basis.

D. Quality of Protection System Equipment

Protection system components must perform under extreme environmental and electrical transient conditions. Therefore, equipment ratings must meet or exceed ANSI and IEEE Standards, i.e., all protective relays must meet or exceed the most recent version of ANSI/IEEE Standard C37.90. In addition, protection systems must include design, maintenance, and testing features as follows:

1. Equipment Quality

The Intertie Protection System equipment, including auxiliary equipment and instrument transformers, must be utility grade (of suitable quality, proven design and commonly used in similar applications).

2. Primary Wiring

All primary or high-voltage wiring of CTs, VTs, breakers, etc., shall be in accordance with all applicable sections of the National Electrical Safety Code, State Codes, Local Codes, Company standards and all standards of prudent electrical practice.

Footnote 2. The relay can protect a generator from abnormal voltage, abnormal frequency, motoring (loss of prime mover), phase faults, ground faults, and unbalanced currents. In addition, sync check may be applied for proper connection of the generator to the bus.

3. Secondary Wiring

All secondary wiring and connections on the Intertie Protection System and its associated equipment shall meet all requirements of applicable National, State, and Local Electrical Codes and all standards of prudent electrical practice.

All intertie relay trip outputs must be hard-wired directly to the tie breaker or interposing lock-out device. No intertie relay trip may be wired through, or derived from, any interposing device, such as a programmable logic controller (PLC) or a plant process computer.

Screws, studs, nuts, and terminals used for Intertie Protection System electrical connections shall be nickel plated brass/copper alloy. The wire used will be no smaller than #14 AWG stranded copper, except wire used for grounding of CT and VT circuits will be no smaller than #12 AWG. All wire insulation will be cross-linked polyethylene or equivalent high quality insulation (type "SIS" or equivalent). Polyvinyl chloride insulation is not permitted. The minimum rating for insulation is 600 volts. Wire terminations must utilize solderless, "Crimp-Style" ring lug terminals. "Spade" or "Fork" type lug terminals are not permitted.

E. Primary Interrupting Device

The Generator's facility must be connected to the EPS through a primary interrupting device. This device must be capable of interrupting the maximum fault current available at the facility. If this device is a breaker, it must be capable of opening after loss of either the facility's generation, the EPS, or both. In addition, this breaker must have the ability to be electrically tripped (opened) by the Intertie Protection System. If this device is a fuse, it must be sized in consideration of the facility's kVA rating and the maximum available fault current at the facility.

In certain installations, high-side fault protection may be provided by the Company's remote-end line protection. In these specific installations, a high side fault interrupting device may not be initially required providing no other Company customers are affected by remote-end tripping. However, future changes to the EPS may require the Generator to install a high-side fault protection device at a later date. Under these circumstances, if the Company determines that high-side fault protection is necessary, the Generator will be responsible for the cost of installing the necessary equipment.

F. Trip Source (Battery)

The source of tripping and/or control power must be a storage battery, equipped with a battery charger, and designed and suitable for the intended use. (Small induction generators may be exempt from this requirement based upon the design of the protection systems involved.) This trip source will be ungrounded and equipped with a ground detection system.

The battery must have sufficient capacity, in accordance with appropriate IEEE Standards, to permit operation of the station in the event of a loss of the battery charger or AC supply. The battery charger must be capable of supplying the station load and be able to charge the battery. The charger shall be equipped with over/undervoltage alarms, loss of AC to charger alarm, and a battery ground alarm.

All DC peripheral devices must be fused separately from the protection systems, including the breaker trip coil(s). This will prevent the failure of any other device from jeopardizing the security of the protection systems. Use of AC voltage, or use of the generator exciter as a source of DC power, is not an acceptable alternative to the battery and charger system. The battery and breaker trip coil must be a nominal 48 volts DC, minimum. The breaker trip coils and relay circuits must be monitored for loss of DC.

G. Islanding

Islanding is the operation of the Generator's facility supplying an isolated portion of the EPS. This operation can create hazards to personnel, other customers, and the general public, and may cause equipment damage. Because of the hazards involved, islanding must be avoided, except as provided for in Section II.F.4, "Islanded Generation Limits." Where it is allowed, the Generator's facility shall be designed with appropriate control and protection systems to safely supply connected loads while islanding.

In situations where islanding is not allowed and the Generator's facility is not immediately disconnected from the EPS after the utility breaker opens, additional relaying and/or communications equipment will be required, at the Generator's expense. See Section I, "Transfer Trip," below.

H. Automatic Reclosing

The Company utilizes automatic reclosing to reduce outage durations of the T&D system. Should a utility recloser open due to a detected fault condition, that recloser will automatically reclose. The Generator's equipment, the EPS, and other Company customers' equipment is susceptible to damage if the recloser closes back in while the Generator is still connected to the EPS. Additional fault interrupting devices may exist between the utility substation breaker and the Generator's facility. Generators are responsible for protecting their equipment from automatic or manual reclosing of all such utility devices.

I. Transfer Trip

The Company may require, or the Generator may request that the Company install, transfer trip equipment as additional protection against the Generator's facility backfeeding a portion of the EPS. This equipment shall provide separation of the Generator's facility from the EPS in the event of system disturbances detected by utility equipment remote from the Generator's facility. The Generator will be responsible for all costs associated with the installation, operation, and maintenance of such equipment, including the installation and ongoing costs associated with any required communications channels.

The Generator may be required to provide local breaker failure protection, which may include direct transfer tripping to the utility line terminal(s), in order to detect and clear faults within the Generator's facility that cannot be detected by the Company's back-up protection.

J. The Company' Underfrequency Load Shedding Program

The Underfrequency Load Shedding (UFLS) program is designed to match load to generation for the loss of a major tie line or the significant loss of generation, and to return the system frequency to acceptable limits following such a loss. The Company must review and report annually to the ISO-NE and NPCC on this program. Frequency relaying installed as part of the Intertie Protection System and the Generator Protection System will be set according to criteria which will allow the Company to meet UFLS program goals.

Each Generator is responsible to review the setting criteria to ensure that the Company specified settings will not unduly stress their generating equipment. In instances where these settings cannot be implemented in accordance with this criteria, or where generator controls or auxiliary equipment prevent generator operation at these frequencies, the Company will install alternate load relief to compensate for the lost generation. The Generator will be responsible for the cost of providing and maintaining this alternate load relief.

Generators that have other frequency and/or speed control devices not required by the Company must coordinate the setpoints of these devices with the intertie frequency relay settings specified by the Company. If there is no intertie frequency relay, these other devices must be set to meet the UFLS program. The Generator will be responsible to test any of these additional devices and maintain this test information on file. Such information will be provided to the Company upon request.

K. Black Start Capability

In order to meet the requirements of ISO-NE Operating Procedures, certain generators interconnected to the EPS may have black start capability. These generators must be able to start without an external power source, to allow for restoration of the EPS in the event of a system-wide outage. This capability must be tested annually in accordance with ISO-NE Operating Procedure #11, unless conducting such a test would interrupt firm customer load. In this instance, the testing interval will be as agreed to by the Generator and the Company on a case-by-case basis.

L. Generator Facility Acceptance

Before interconnected operation with the EPS can begin, the Generator's facility must be inspected by the Company to verify that protection system requirements are met, that operability of Intertie Protection System is verified, that SCADA communications and data points have been commissioned, and that all appropriate testing has been completed. To facilitate this process, the Generator will assign a professional engineer currently licensed in the state of Maine. This person will certify in writing (PE Stamped Letter) that all testing and commissioning has been completed and the facility is ready to be energized. This individual will also act as the liaison between the Generator and the Company until the interconnection requirements have been met.

Ninety (90) Calendar days prior to the initial functional test, the Generator shall supply construction grade protection and control drawings to the Company. These drawings must provide sufficient information for the Company to analyze all functional test requirements specified below.

- CTs: rating, circuit polarity, ratio, insulation, excitation, continuity and burden tests.
- VTs: rating, circuit polarity, ratio, insulation and continuity tests.
- Relay pick-up and time delay tests.
- Functional breaker trip tests from protective relays.
- Relay in-service tests to check for proper phase rotation and magnitudes of applied currents and voltages.
- Breaker closing interlock tests.
- Paralleling and de-paralleling operation.
- Other relay commissioning tests typically performed for the relays involved.

The Generator will provide the Company a copy of all test data for evaluation fourteen (14) calendar days prior to energization. The Company will perform or observe a functional test and commissioning of the entire Intertie Protection System. This will include a calibration check of the intertie protective relays and as many trips of the intertie breaker and/or the generator breaker(s) as the Company considers necessary to verify the correct operation of the Intertie Protection System and the breaker trip circuits. Phase rotation and synchronizing will also be verified.

To facilitate this testing, test points must be accessible to permit injection of test voltages or currents to verify the calibration and operation of the components making up the Intertie Protection System. One means of providing these test points is incorporating ABB FT or GE PK test blocks into the facility design. These test points shall also interrupt the protection system trip outputs. The Company will review and approve the testability of the Intertie Protection System as part of the initial design review.

After the final commissioning, the Generator must provide the Company with one set of accurate drawings and maintain one set on-site. Any subsequent changes to the facility impacting the Intertie Protection System must be approved by the Company before being incorporated. After incorporation, such changes must be verified by the Company and documented and incorporated into the facility prints within ninety (90) days. A set of updated prints will be provided to the Company within this time-frame.

M. Synchronizing to the T&D System

All components of the Intertie Protection System, the Generator Protection System, the synchronizing circuits, and all SCADA communications and data must be energized and functioning correctly before the Generator will be allowed to begin parallel operation with the EPS.

The Generator is solely responsible for properly synchronizing to the EPS. The circuit breakers associated with the generating units must be equipped with facilities to automatically or manually synchronize the generating unit with the EPS. All synchronizing must be performed with the aid of either a synchronizing relay or a synchroscope. A sync check relay is recommended to prevent catastrophic errors during the synchronizing process. New units larger than 1 MVA directly connected to distribution load must be equipped with automatic synchronizing.

NOTE: For facilities 1,000 kW or greater, the Generator must notify the Maine Local Control Center (the Company's Energy Control Center) prior to connecting or disconnecting any generation or station load on the EPS when such action is a planned operation.

The Company requires a detailed procedure from the Generator for the initial synchronization. The Generator's actual synchronizing procedure will require approval from the Company. See Figure III-1 for a sample procedure. Upon complete implementation of the Generator's procedure, assuming that all technical requirements have been met, the Generator will be allowed to connect to the EPS and begin parallel operation.

NOTE: The Maine Local Control Center (the Company's Energy Control Center), must be notified at least 5 business days prior to the initial synchronizing to the EPS by calling 1-800-750-2976 or 1-800-750-6934.

THE INITIAL SYNCHRONIZATION SHALL BE WITNESSED BY THE COMPANY.

N. Typical Installations

The installations listed in this section provide the important characteristics of connecting to a distribution line or transmission line. In general, a distribution line has only one connection with the rest of the EPS. Transmission line and substation busses generally have two (or more) connections with the rest of the EPS, and are typically of higher voltage. 115 kV and 345 kV are the nominal phase-to-phase transmission voltages within the EPS. The Company also has a 34.5 kV subtransmission system.

The following subsections give a general overview of acceptable interconnection designs. Figures III-2 through III-6 are one-line diagrams for the installations listed below. Figure III-7 provides a legend of symbols used in the one-line diagrams. ALL INSTALLATIONS MUST BE REVIEWED AND APPROVED BY THE COMPANY PRIOR TO FINAL ACCEPTANCE AND COMMISSIONING.

Synchronous Generation

Type	Rating	Transformer Configuration (HV-LV)	Utility Connection
I	1-phase ≤ 25 kW	Single-phase	Distribution
II	3-phase ≤ 100 kW	Wye-Delta	Distribution
III	3-phase > 100 kW	Wye-Delta	Distribution
IV	Any size 3-phase	Wye-Delta	Transmission
V	Any size 3-phase	Wye-Delta	Transmission-Bus
VI	Any size 3-phase	Wye-Delta	Subtransmission

Inverter Based Resource (IBR) – Distribution Only

Type	Rating	Transformer Configuration (HV-LV)	Utility Connection
I	1-phase ≤ 25 kW	Single-phase	Distribution
II	3-phase ≤ 100 kW	Wye Grnd-Wye Grnd	Distribution
III	3-phase > 100 kW	Wye-Grnd-Wye Grnd	Distribution

Notes:

1) If a generation facility cannot use the Yg-Yg GSU winding configuration, the Interconnection Customer should contact CMP Interconnection Services for site specific acceptable alternatives.

2) Transmission IBRs should reference Section III.B (Transformer Connections).

Purpose: To verify proper rotation and phase relationships of primary and secondary circuits of Generator's generator and the T&D system prior to connection.

Discussion: Both the incoming and running VTs will be energized from a common source.

Rotation and phase angle checks will be taken on both VTs and the synchronizing circuits will be verified for correct operation.

Precautions: To prevent personnel injury and motoring the generator, the links between the generator and the main bus shall be removed prior to performing any switching.

The safety of the plant will be the Generator's responsibility.

Prerequisites:

- Verify that all relay and control testing has been completed and the unit step-up transformer and all other pertinent equipment is ready for energization.
- Verify that 86 devices have been reset.
- Verify generator and transformer relays are operable.
- Verify transformer auxiliaries are ready to be energized and operable.
- Signature ____________________________________

Procedure:

a. Energize main step-up transformer from the T&D system.
b. Read and record rotation on running VTs.
c. Read and record bus voltage on running VTs for all 3-phases.
Phase A ___________
Phase B ___________
Phase C ___________ By: ___________________
d. Close generator breaker to energize incoming VTs.
e. Observe synchroscope is at 12 o'clock position. If not at 12 o'clock position, STOP and inform the Company.
By: _________________________
f. Read and record rotation on incoming VTs. Should be the same as running VTs. If not, STOP and inform the Company.
By: _________________________
g. Read and record bus voltage on incoming VTs for all 3-phases.
Phase A ___________
Phase B ___________
Phase C ___________ By: ___________________
h. Should be the same as running VTs. If not, STOP and inform the Company.
By: _________________________
i. Return system to normal.
j. Reinstall generator links.
k. Rack generator breaker into test position.
l. Bring unit up to rated speed and voltage.
m. Using a strip chart recorder, record voltage and speed matching capability.
n. Allow auto synchronizing equipment to close generator breaker in test position. Record phase angle difference between generator bus and the T&D system at time of closing. Mismatch must be less than 1% between the incoming and running voltmeter. The phase difference must be zero. (This information required to be on file with the Company.)
o. Open the generator breaker.

NOTE: If provisions have been made for manual synchronizing, the operator must demonstrate his ability as follows:

p. Select sync selector to "Manual".
q. Adjust unit speed allowing at least 6 seconds per revolution on the synchroscope (generator faster than the T&D system).
r. Adjust voltage to less than 1% voltage mismatch.
s. At 6 seconds per revolution, the operator would initiate the close pulse approximately 5 degrees prior to the 12 o'clock position.
t. Record phase angle difference between generator bus and the T&D system at time of closing.
u. Rack generator breaker into normal operating position and repeat synchronizing procedures n. through t.
By: _________________________________ (This information required to be on file with the Company.)

Final Conditions:

- Synchronizing procedure has been completed.

Date/Time: __________________

Operator: __________________

Figure III-1: Sample Synchronizing Procedure for Commissioning.

1. TYPE I INSTALLATIONS (Figure III-2)

These are small, single-phase, induction generators or static power converters connected to a distribution circuit, usually 12 kV (7200 V phase to neutral). These units are usually protected by a molded case circuit breaker and utilize a separate contactor for controlling the generator connection. They require one over-frequency relay, one under-frequency relay, one over-voltage relay, and one under-voltage relay to control the contactor. Utility voltage must be re-established and stable before the Generator is allowed to reconnect. While some power may flow onto the T & D system from this type installation, the primary purpose of this type installation is to supply power to the home or small business to which it is connected. The following are typical characteristics of the Type I installation:

- Designed by a manufacturer as a complete system and meeting UL1741 and/or IEEE 1547 standards planned for a connection to a 240 V, 2-pole molded case breaker.

- Contactor is sized in accordance with the manufacturer's specifications. In the absence of a manufacturer's specification, this contactor will be sized no less than 2.0 times the available current at the rated output (KVA) of the generator/static power converter.

- Details shown on Figure III-2 for this Type I installation provide the important characteristics of the design philosophy for connecting to the Company system and are not intended to be inclusive of all project specific requirements. Location of a proposed Generator within the Company system may extend the requirements shown to ensure reliable dispatch, control, and protection for both the Company and Generator.

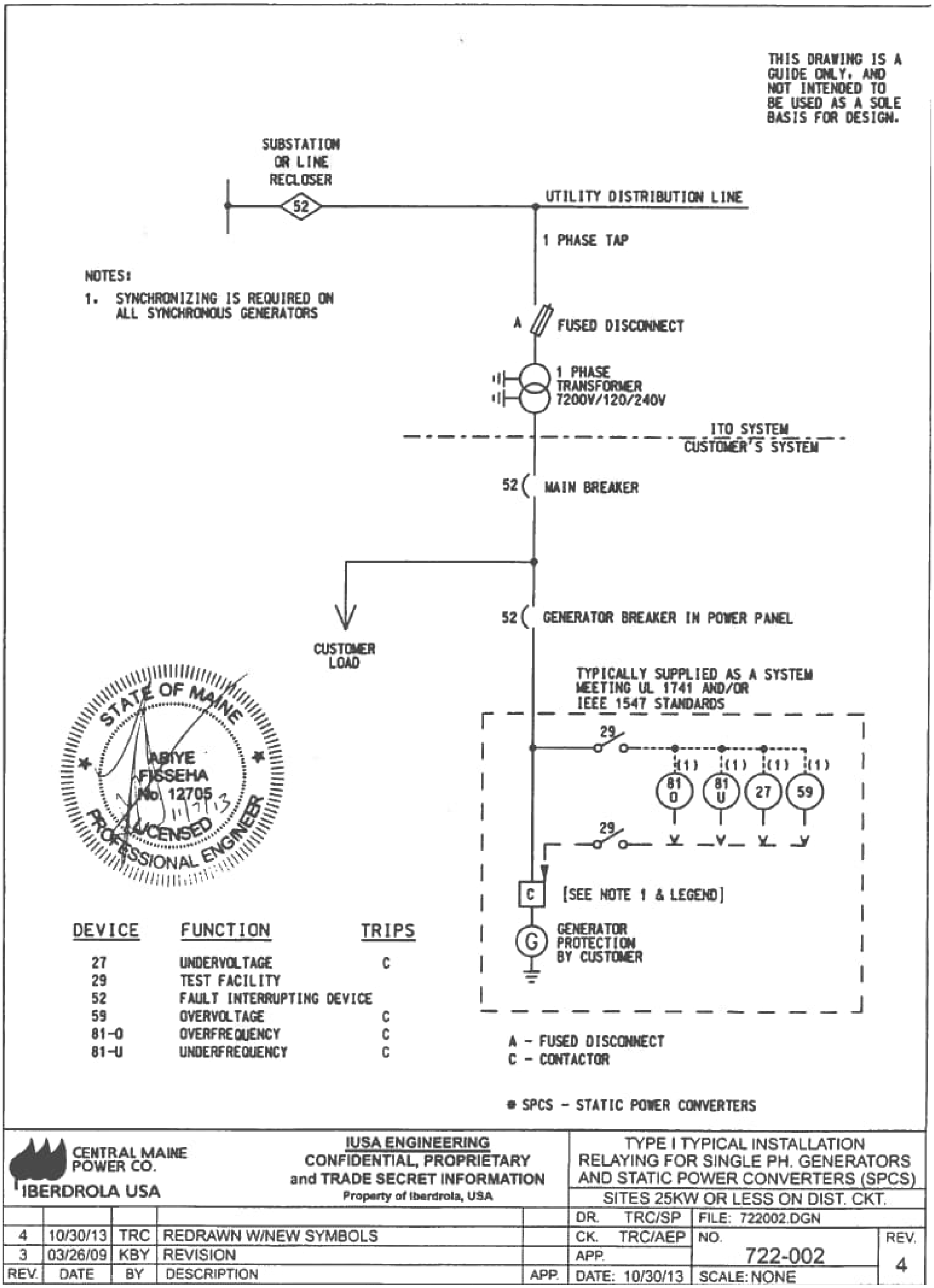

Figure III-2: Type I Typical Installation.

2. TYPE II INSTALLATIONS (Figure III-3)

These are three-phase generators (induction or synchronous) or static power converters with a maximum generation of 100KW connected to a distribution circuit, usually 12 kV (7200 V phase to neutral). This installation provides for power flow from the Generator's facility to the T & D system. However, the primary reason for the generation may be to supply the Generator's own load.

- This installation requires a primary circuit breaker, circuit switcher, recloser, or contactor designated as component "52G" in Figure III-3.

- If fused on the high-side, the fuse size will be specified by the Company based on the generator output, the Generator facility's load, and the available fault current at the generator's location.

- The Generator's control scheme for breaker "52M" must be designed to allow for its closing only if the feed from the Company is energized, and breaker "52G" is open. If breaker "52M" is open and breaker "52G" is closed, the Generator may synchronize across breaker "52M." If the feed from the Company is not energized, then the Generator's control scheme must prevent closing of breaker "52M." If "52M" is a fuse, the Generator's control scheme must prevent closing of "52G" if the feed from the Company is not energized.

- Voltage Transformers providing sensing input to Inter-tie Protective Relays must be continuously rated for line-to-line voltage.

- Details shown on Figure III-3 for this Type II installation provide the important characteristics of the design philosophy for connecting to the Company system and are not intended to be inclusive of all project specific requirements. Location of a proposed Generator within the Company system may extend the requirements shown to ensure reliable dispatch, control, and protection for both the Company and Generator.

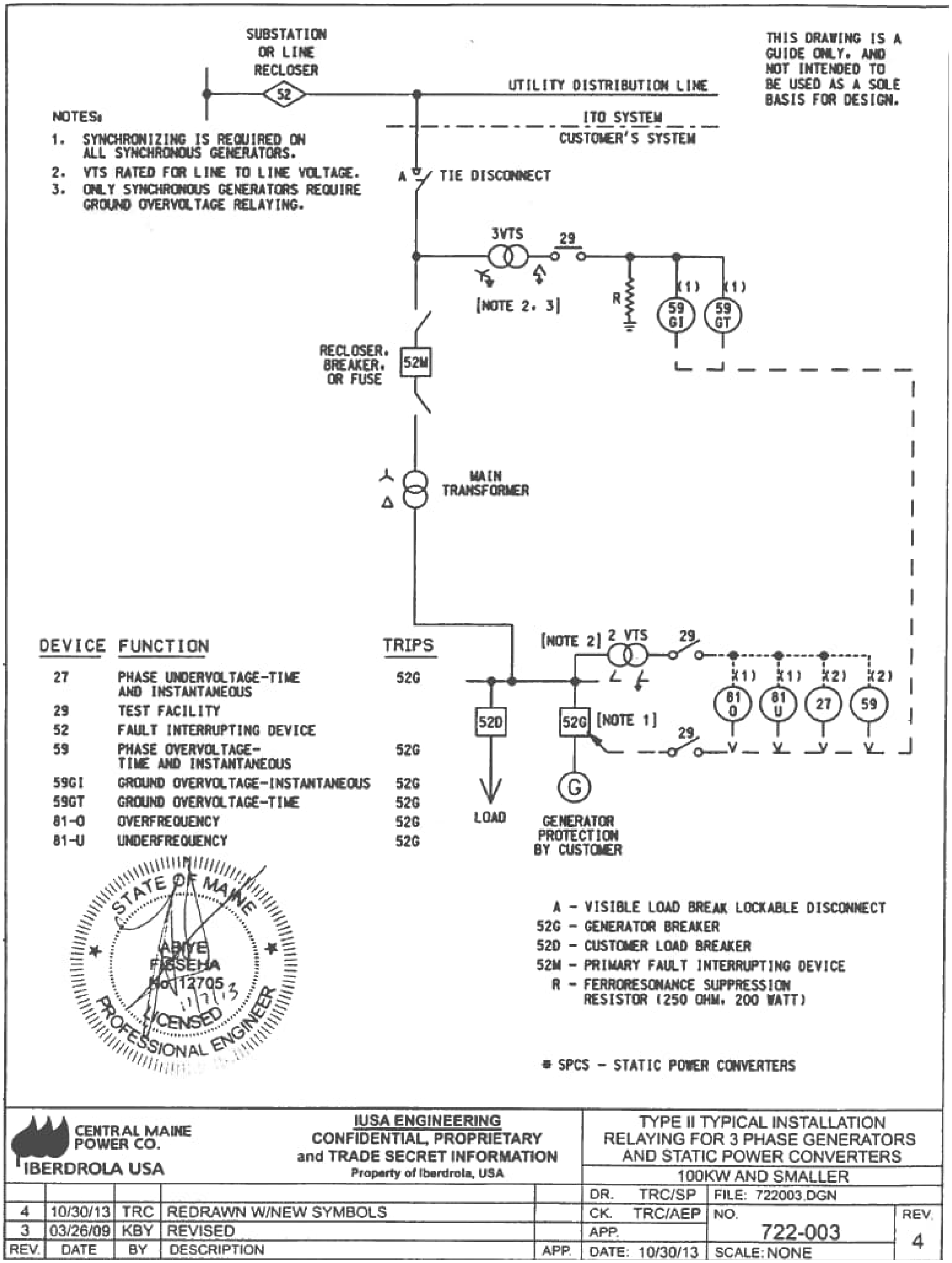

Figure III-3: Type II Typical Installation.

3. TYPE III INSTALLATIONS (Figure III-4)

These are three-phase generators (induction or synchronous) or static power converters with generation greater than 100 kW connected to a distribution circuit, usually 12 kV (7200 V phase to neutral). This installation provides for power flow from the Generator's facility to the T & D system as a normal operating mode. However, the primary reason for the generation may be to serve the Generator's own load.

Typically, a distribution circuit can accept up to 1 MVA of generation with the Inter-tie configuration shown in Figure III-4. The Company will study any facility greater than 1 MVA and may study smaller facilities in this category to determine if additional or different Inter-tie protection equipment is required.

- This installation requires a primary circuit breaker, circuit switcher, recloser, or fuse designated as component "52L" in Figure III-4, that is capable of interrupting the maximum available fault current at this location.

- The Generator's control scheme for breaker "52L" must be designed to allow for the closing of "52L" only if the feed from the Company is energized. If the feed from the Company is not energized, then the Generator's control scheme must prevent closing of breaker "52L."

- It may be desirable to have synchronizing equipment on breaker "52L" as well as breaker "52G."

- The Company may require a transfer trip system, at the Generator's expense, to allow automatic separation of the generator from the T & D system in the event of system disturbances detected by utility equipment remote from the generating site.

- Voltage Transformers providing sensing input to Inter-tie Protective Relays must be continuously rated for line-to-line voltage.

- Details shown on Figure III-4 for this Type III installation provide the important characteristics of the design philosophy for connecting to the Company system and are not intended to be inclusive of all project specific requirements. Location of a proposed Generator within the Company system may extend the requirements shown to ensure reliable dispatch, control, and protection for both the Company and Generator.

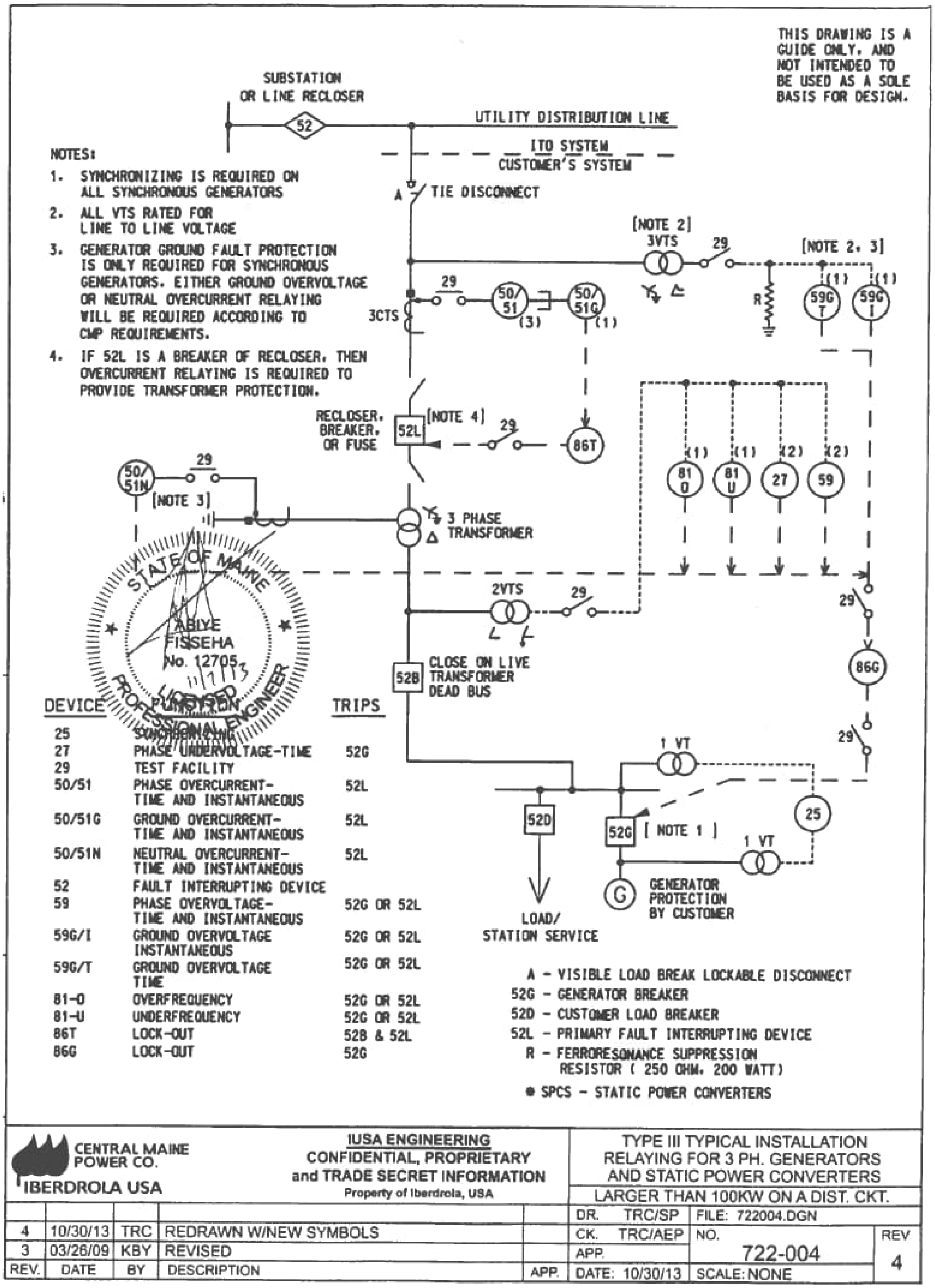

Figure III-4: Type III Typical Installation.

4. TYPE IV INSTALLATIONS (Figure III-5)

CONNECTED TO COMPANY TRANSMISSION LINE - NO EXISTING SUBSTATION

These are three phase generators interconnected to the 115 kV or 345 kV transmission system. This installation provides for power flow from the Generator's facility to the Company as a normal operating mode. A new interconnecting Company substation is required.

- This installation requires a primary circuit breaker or circuit switcher designated as component "52L" in Figure III-5 capable of interrupting the maximum available fault current at this location.

- Energy Control Center directly controls the operation of all switching devices on the utility transmission system. On this type installation, the Generator's switches affected are the tie disconnect switch, the station grounding switch, and "52L."

- The Generator's control scheme must be designed to allow for the closing of breaker "52G" only if the feed from the Company is energized or breaker "52L" is open. If breaker "52L" is open and breaker "52G" is closed, the Generator may synchronize across breaker "52L". If the feed from the Company is not energized, then the Generator's control scheme must prevent closing of both breakers "52G" and "52L." Black start facilities will require an override to this control that will be utilized only under the direct authorization of Energy Control Center.

- This installation requires pilot channel relaying and/or transfer trip for high speed fault clearing capability.

- The Company may require a transfer trip system, at the Generator's expense, to allow automatic separation of the generator from the T & D system in the event of system disturbances detected by utility equipment remote from the generating site.

- Voltage Transformers providing sensing input to Inter-tie Protective Relays must be continuously rated for line-to-line voltage.

- When interconnecting to the Bulk Power System (BPS), the Company will require the Generator to provide two independent, redundant protection systems in accordance with ISO New England and NPCC criteria. This will also be required for facilities interconnected to the transmission system if the Company determines that delayed clearing of faults within the Generator's facility could adversely affect the BPS system.

- Details shown on Figure III-5 for this Type IV installation provide the important characteristics of the design philosophy for connecting to the Company system and are not intended to be inclusive of all project specific requirements. Location of a proposed Generator within the Company system may extend the requirements shown to ensure reliable dispatch, control, and protection for both the Company and Generator.

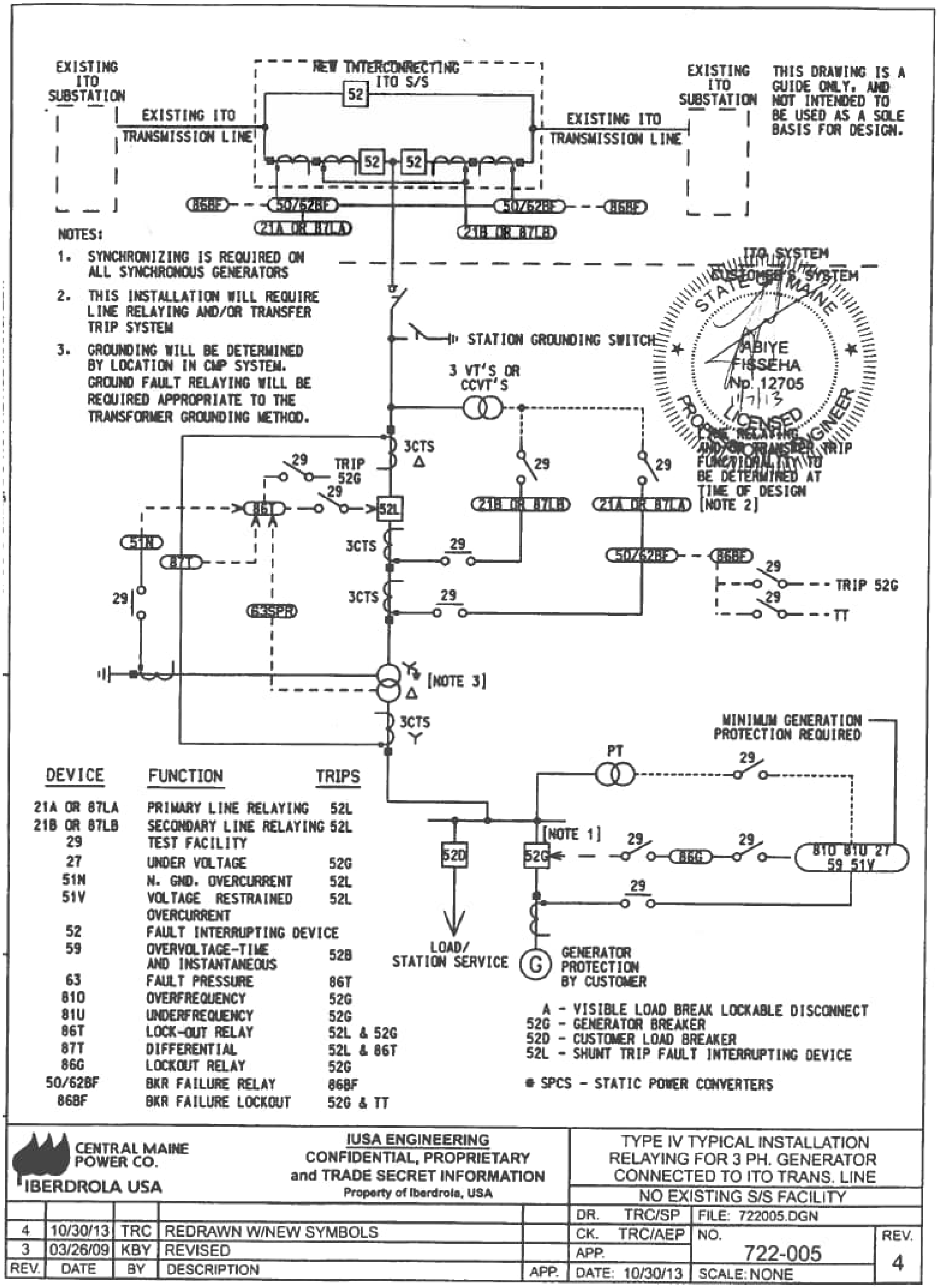

Figure III-5: Type IV Typical Installation.

5. TYPE V INSTALLATIONS (Figure III-6)

CONNECTED TO COMPANY TRANSMISSION SUBSTATION

This installation is interconnected to the utility transmission system through an existing 34.5 kV, 115 kV, or 345 kV substation. The substation will be connected to at least two (2) utility transmission line sections. This design provides for power flow from the Generator's facility to the utility as a normal operating mode.

Because the facility is connected to a transmission substation, some of the standard inter-tie protection for the other installation types may not be required. Specifically, over/under frequency and undervoltage protection may not be required where a Generator will not island to serve local distribution load. As shown in Figure III-6, other protection, such as bus differential relaying may be required to meet site-specific conditions.

- As with the Type IV installation, a primary breaker is required, rated to interrupt maximum available fault current designated as "52B" in Figure III-6. This breaker, along with the associated breaker disconnects, bypass switch, and grounding switch will be under the direct control of Energy Control Center.

- The Generator's control scheme must be designed to allow for the closing of breaker "52G" only if the feed from the Company is energized or breaker "52L" is open. If breaker "52L" is open and breaker "52G" is closed, the Generator may synchronize across breaker "52L." If the feed from the Company is not energized, then the Generator's control scheme must prevent closing of both breakers "52G" and "52L." Black start facilities will require an override to this control that will be utilized only under the direct authorization of Energy Control Center.

- The Company may require a transfer trip system, at the Generator's expense, to allow automatic separation of the generator from the T & D system in the event of system disturbances detected by utility equipment remote from the generating site.

- When interconnecting to the Bulk Power System (BPS), the Company will require the Generator to provide two independent, redundant protection systems in accordance with ISO New England and NPCC criteria. This will also be required for facilities interconnected to the transmission system if the Company determines that delayed clearing of faults within the Generator's facility could adversely affect the BPS system.

- Details shown on Figure III-6 for this Type V installation provide the important characteristics of the design philosophy for connecting to the Company system and are not intended to be inclusive of all project specific requirements. Location of a proposed Generator within the Company system may extend the requirements shown to ensure reliable dispatch, control, and protection for both the Company and Generator.

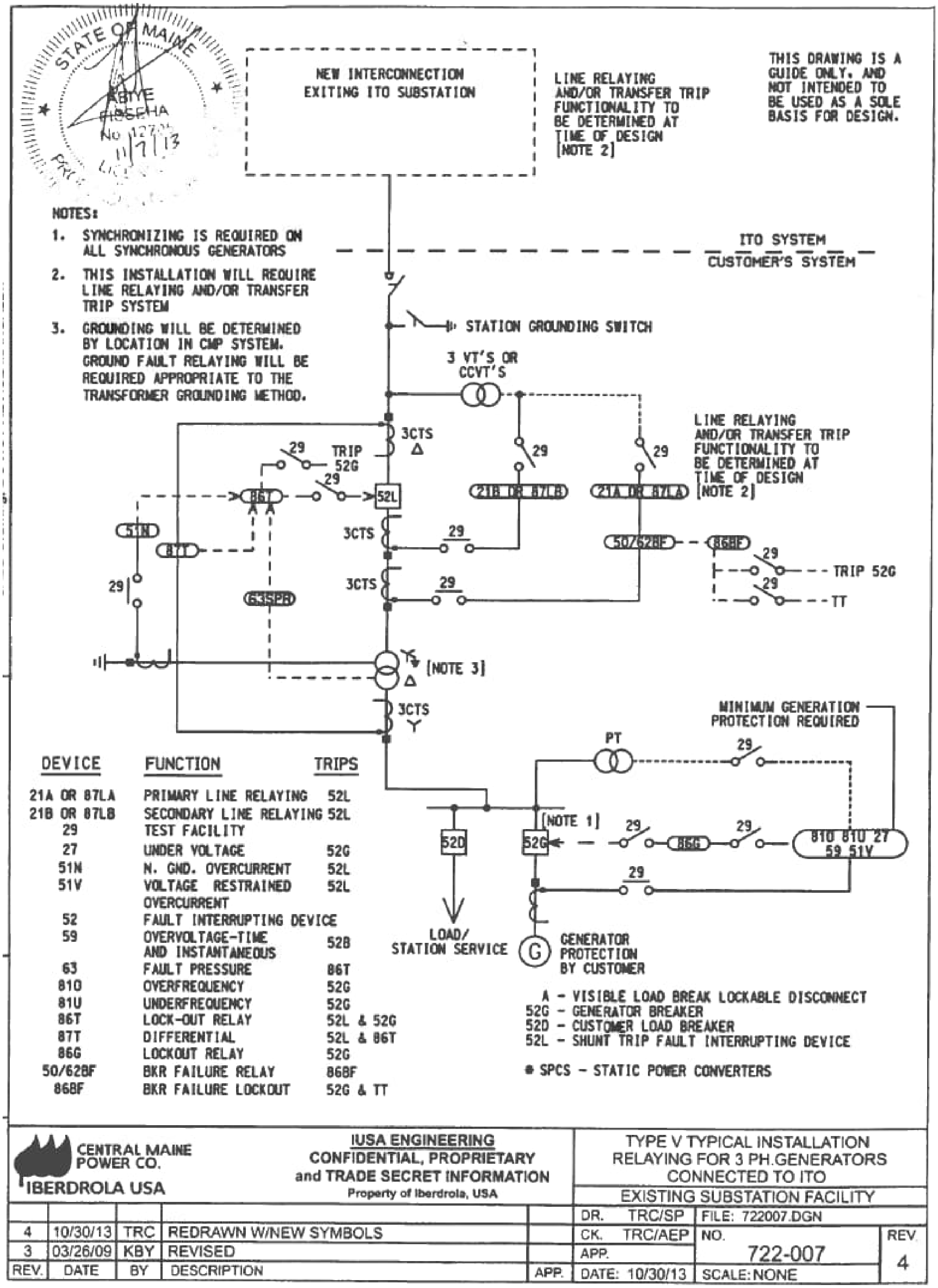

Figure III-6: Type V Typical Installation.

G	GENERATOR NOT CMP OWNED
	TRANSFORMER, 1 PHASE OR 3 PHASE
	TRANSFORMER, VOLTAGE (VT, PT)
	TRANSFORMER, CURRENT (CT)
	FAULT INTERRUPTING DEVICE (OIL, VACUUM, SF6, AIR BLAST)
	SINGLE POLE DISCONNECT SWITCH
	3 PHASE GANG-OPERATED DISCONNECT SWITCH (BKR DISC, ETC.)
	SINGLE POLE INTERUPPTER SWITCH
	3 PHASE GANG-OPERATED INTERUPPTER SWITCH
	3 PHASE GANG-OPERATED GROUND SWITCH
	3 PHASE AIR SWITCH, HORN GAP & ARC RESISTORS
	GROUND
	FUSE
	LINE TRAP
	COUPLING CAPACITOR VOLTAGE TRANSFORMER
	RESISTOR
XXXX	LINE TUNING UNIT
TX	TRANSMITTER
RX	RECEIVER
	CONNECTION
	CONTROL RELAYING TEST BLOCK
	CONTROL RELAYING
	ENCLOSES STATIONS, LINES, AND/OR EQUIPMENT NOT CMP PROPERTY

STATE OF MAINE
~~ABIYE FISSEHA~~
No. 12705
11/7/13
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PROFESSIONAL ENGINEER

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LEGEND
SCHEMATIC SYMBOLS USED ON TYPES I - V
TYPICAL INSTALLATIONS

REV.	DATE	BY	DESCRIPTION	APP.
1	10/30/13	TRC	REDRAWN W/NEW SYMBOLS	

DR. TRC/SP	FILE: 722006.DGN	
CK. TRC/AEP	NO. 722-006	REV. 1
APP.		
DATE: 10/30/13	SCALE: NONE	

Figure III-7: Legend of Schematic Symbols.

6. TYPE VI INSTALLATIONS

These are three-phase generators (synchronous or induction or inverter based) interconnected to the utility subtransmission system (34.5 kV). The interconnection requirements for this type installation could be the same as a Type III or Type IV facility or could lie somewhere in between the requirements for these installation types. Interconnection to the utility subtransmission system (34.5 kV) typically requires a three-breaker ring bus.

O. Protection System Device Numbers and Functions

<u>Device</u>	<u>Description</u>
21P	**Primary Line Relaying**
	This relay is required to interface with remote terminal relaying and requires some type of transfer tripping or pilot communications scheme.
27	**Undervoltage Relay**
	This relay is used to detect a low voltage condition and is usually set at 90% of nominal system voltage.
29	**Test Facility**
	This device is used to isolate components and relays from their respective source(s) and load(s) to facilitate maintenance and testing.
32	**Reverse Power**
	This directional protective relay prevents power from flowing in the reverse direction and is used to ensure non-exporting generators operating in parallel with the Company do not export onto the EPS.
50/51	**Overcurrent Relays**
	These relays are used to detect transformer faults and initiate tripping of the intertie breaker without causing loss of service to other Company customers. The time overcurrent element will be set to coordinate with the Company’s line relaying. The instantaneous element will typically be set to provide high-speed clearing of transformer internal faults.
50/51G	**Ground Overcurrent Relay**
	This relay is used to detect feeder unbalance and coordinate with other protective devices on the circuit.
50/51N	**Neutral Ground Overcurrent Relay**
	The time overcurrent and instantaneous elements of this relay are used to detect bus ground faults by sensing a transformer neutral current.
51V	**Voltage Controlled Overcurrent Relay**
	This relay is used to detect feeder faults and to trip the Generator’s facility when coordination with other protective devices on the circuit is required. The overcurrent element is typically set considering the generator’s damage curve. The voltage element will typically operate at 80% of normal system voltage to obtain the clearing required yet maintain the generation during a sag in system voltage.
52	**AC Circuit Breaker**
	A device used to close and interrupt an AC power circuit under normal conditions and to interrupt the AC circuit under fault or emergency conditions.
59	**Overvoltage Relay**
	The time overvoltage element on this relay is required to detect an high voltage condition. It will be set 10% above the normal system voltage on distribution circuits and 15% above the nominal system voltage on transmission circuits.

The instantaneous element may be required to detect ferroresonance or extreme overvoltages possible during fault conditions. It will be set 20-30% above the normal system voltage.

Device	Description
59G/I	**Instantaneous Ground Overvoltage Relay**
	This relay is used to detect ground faults when the high-voltage side of the generator step-up transformer is ungrounded. This relay requires three voltage transformers connected grounded-wye on the high-side and broken-delta on the low side. The 59G/I relay is connected across the broken delta to measure the zero sequence voltage (Vo) on the feeder. It is normally set at approximately 110% of the rated single phase VT secondary voltage and provides protection for extreme ground overvoltage conditions. This relay must also be able to withstand 3 times the rated single phase VT secondary voltage.
59G/T	**Time Ground Overvoltage Relay**
	This relay is used for the same purpose and connected in the same manner as the 59G/I relay. The overvoltage relay must be able to withstand 3 times the rated single phase VT secondary voltage, and is usually set for approximately 20% of the single VT secondary voltage with a time delay of approximately 1 second.
81O/U	**Over and Underfrequency Relays**
	Used to prevent islanding of the generator facility with other Company customers. These relays shall be set in accordance with NPCC Regional Reliability Reference Directory 12.
87T	**Transformer Differential Relay**
	This relay is used to detect internal transformer faults and is required on larger installations to coordinate with transmission line relaying.

NOTE - for any generator connected to the Bulk Electric System (BES) there are additional/separate reliability standard setting requirements that supersede the Company's setting requirements. For NERC generators, the applicable reliability standards take precedence over the Company's setting requirements.

P. Exceptions

While the majority of installations have been discussed, this document cannot cover every possible contingency or variation in equipment to be encountered at the various Generator installations. Questions on the protective relaying to be used at any installation not covered by this document shall be addressed to the Company.

Q. LROV Protection (Inverter-Based Distribution)

Load Rejection Overvoltage (LROV) is defined by IEEE C62.92.6-2017 as a "Temporary or transient overvoltage resulting from abrupt disconnection of all or a portion of the load of a generation source." Surge arrestors at the POI will be required if the Generation to Load ratio at the substation transformer is > 10 or when the Generation to Load ratio is <= 10 and no documentation of HECO compliance for the inverters has been supplied to the Company.

IV. Metering

Any location where a Generator's facility is connected in parallel with the EPS will be metered to measure energy flow in two directions. The metering requirements contained herein assume bi-directional metering at the POI. Any other metering arrangement will require approval of, and design by, the Company.

A. In and Out Metering

Metering of energy flowing from the EPS into a customer is known as "IN" Metering and metering of energy flowing out from a Generator's facility to the EPS is known as "OUT" Metering. Bi-directional solid state meters are capable of measuring both "IN" and "OUT" metering within a single meter.

B. Metering Location

Metering shall be located at the point of delivery whenever practicable. Advance Company approval of metering location is required.

Loss compensation is required if the metering equipment is not installed at the point of delivery. Loss compensation is determined based upon CMP Terms and Conditions 12.8 METER LOCATION ADJUSTMENT and ISO NE's OP-18 Metering and Telemetering Criteria.

When service is metered at a lower or higher voltage than the delivery voltage, the measured kWh will be increased or decreased by a fixed percentage or, at the option of the Company, a continuous on-site adjustment will be made through compensating metering equipment or a factor applied based on the transformer manufacturer's data.

If a fixed factor is used to compensate metering equipment, the fixed factor shall be calculated using the peak output rating of the generator. The fixed factor will take into account all transformer losses and line losses between the metering point and the point of delivery.

Loss compensation programmed into the meter is based on transformer and line characteristics.

When necessary to compensate for transformer losses, the following information is required; transformer primary voltage, transformer secondary voltage, full load kVA, no load percent exciting current, no load Watt loss, full load percent impedance, and full load Watt loss.

When necessary to compensate for line losses, the following information is required; Volts line to line, charging kVARhs, line resistance in Ohms, and line inductance in Ohms.

C. SCADA

SCADA data provisions shall not be sourced from the Meter. The source of the SCADA data shall be sourced by the Generator's RTU device(s).

D. Net Energy Billing

The rule establishing the requirements and terms for net energy billing is the MPUC Chapter 313 "CUSTOMER NET ENERGY BILLING." Under the Net Energy Billing Rules adopted November 24, 2019 the Commission established metering rules applicable for customers that receive kWh credits that differ from metering rules for customers that receive financial credits. The following is a summary of how this rule applies to Metering.

An eligible facility must have an installed capacity of 4.999 kW or less. The eligible facility and the Generator and shared ownership Generator accounts subject to net energy billing must be located within a service territory of the same transmission and distribution utility. The amount of nettable energy is determined by the rules set forth in Chapter 313 as follows.

For kWh credits, Net Energy Billing, the Company will provide, install, own, maintain, and test at its expense the metering equipment required to measure the load and generation of the facility. Metering equipment includes the meter(s) and additional metering equipment required to measure the Generator's load and generation separately such as current transformers, voltage transformers, test switches, and metering control cable.

For customers participating in financial/Tariff Rate Net Energy Billing program, the Customer will be responsible for paying the costs for Revenue Quality Metering and all associated equipment required to enable the Company to report the hourly generation to ISO-NE. The Company will install, maintain, and test at its expense the metering equipment required to measure the total load and generation of the facility. The Customer will be responsible for all costs associated with the installation, maintenance and monthly fees associated with the communications line. Metering equipment includes the meter(s) and additional metering equipment required to measure the Generator's load and generation separately such as current transformers, voltage transformers, test switches, and metering control cable.

The Company's Power Contracts Administration administers the Customer Net Energy Billing Agreements ("CNEBAs"). The following items must be completed before operating a facility in parallel with the Company's EPS.

- <u>A signed contract</u>

One original CNEBA will be sent to the Generator for signatures, which must be witnessed. Both originals should be returned to the Contract Administrator. The Company will execute the CNEBA and will return one executed original to the Generator.

- <u>Meter upgrades</u>

The Generator will arrange for the necessary metering equipment to be installed and coordinate the work with the Company.

The Generator will provide the meter mounting device(s) and any other necessary metering enclosure(s) and cabinets and any metering conduit for the meters per the Company's Handbook of Requirements for Electric Service and Meter Installations. The Customer is responsible for the wiring and panel box work required to separately meter the load and gross generation. The Generator's facilities and existing service entrance equipment may require additional work to be completed in order to separately meter the load and gross generation. For example, a Generator with an existing underground service may require the service cables to be upgraded if the generation exceeds the ratings of the conductors. Another example is a Generator served by a padmount transformer with CTs mounted inside the pad requiring a second padmount transformer with CTs to be installed in order to separately meter the gross generation at the facility. Every generation project will need to be reviewed on a case-by-case basis by the Company in order to determine if the Generator's facilities will require additional work and equipment to separately meter the load and gross generation.

All electrical work must meet National Electrical Code requirements in addition to meeting the Company's requirements listed in the Company's Handbook of Requirements for Electric Service and Meter Installations. The Generator must procure all necessary electrical and construction licenses and permits as required for the work at their facility. All local, state, and federal applicable requirements apply.

<u>Satisfactory Inspection</u>

The Generator must procure all necessary licenses and permits (DEP, EAP, FERC, etc.) as required. All local, state, and federal applicable requirements apply.

The Company requires the installation of specific hardware, such as protective relaying, to ensure that the Company's power quality is maintained. Many pre-manufactured, self-contained systems may already contain such equipment. The Generator will be responsible for the cost of any material requirements.

The Company will inspect and test the interconnection equipment, as necessary. The Generator may be responsible for the cost of the initial inspection and testing.

Upon receipt of acceptable interconnection inspection results, the Generator will be authorized to operate the facility in parallel with the Company's system.

E. "OUT" Metering (Other than Net Energy Billing)

The Company will own, maintain, and test all metering equipment required to measure and record energy flowing "OUT" from the Generator's facility to the EPS. "OUT" Metering equipment will be installed at the Generator's expense (see Section H, "Metering Costs," below).

The Generator must provide the necessary metering conduits and enclosures in accordance with the Company's Contractor's Handbook. **The Generator must also provide the communications service to any required electronic meter with recorder at their own expense.** All metering equipment and installations will be approved, inspected, tested, and maintained in keeping with standard Company policy, as well as state, federal, and ISO-NE requirements, as applicable.

The following guidelines should be used to determine the "OUT" Metering requirements for specific installations:

1. All Installations

All installations, regardless of size, must include kWh and kVARh measurement.

2. Installations with Special Contract Requirements

All installations with special contract requirements (On-peak/Off peak, demand limits) must also include an electronic meter with recorder (remotely interrogated via the **communications service**).

Metering equipment must meet ISO-NE Operating procedure OP 18 requirements.

F. "IN" Metering (Other than Net Energy Billing)

The Company will provide, install, own, maintain, and test at its expense, all “IN” Metering equipment required to measure energy flowing "IN" to the Generator’s facility.

The Company-owned metering devices will normally be located in or on the Generator's structures with access provided for Company personnel. Other arrangements are possible by mutual agreement.

The Generator must provide the necessary metering conduits and enclosures in accordance with the Company’s Contractor’s Handbook. **The Generator must also provide the communications service to any required electronic meter with recorder at their own expense.**

All metering equipment will be inspected, tested, and maintained in keeping with standard Company policy as well as State and Federal requirements, as applicable.

Unless the Company agrees otherwise, the following guidelines must be used to determine the "IN" Metering requirements for specific installations:

1. All Installations

   All installations, regardless of size, must include kWh/kWD and kVARh/kVARD measurement.

2. Installations with Load Greater Than 400 kW

   All installations with load above 400 kW must also include time-of-use measurement (for kWh/kWD and kVARh/kVARD) and an electronic meter with recorder.

NOTE: Both “IN” and “OUT” measurement requirements above may be provided by one (1) solid-state, bi-directional meter.

G. Metering One-Line Diagrams

Diagrams of two typical metering schemes are included as Figures IV-1 through IV-2 at the end of this section.

H. Metering Enclosure Mounting Diagrams

Diagrams of two typical meter enclosure mounting schemes are included as Figures IV-3 and IV-4 as typical reference material. Installation-specific diagrams will be provided by the Company upon request.

I. Company Approval

Company approval must be obtained for the design and specifications of any metering equipment, such as in the case of switchgear installations furnished by the Generator. Factory certification of tests is required for all instrument transformers.

J. Metering Costs

With the exception of Net Energy Billing, the Generator must pay in advance the Company’s estimated equipment and installation cost, including any engineering and computer programming costs, for any “OUT” Metering equipment. This charge will include the cost of bi-directional meters and instrument transformers (VTs and CTs) if their primary purpose is the measurement of energy flowing "OUT" from the Generator's facility to the Company. In the case of existing installations, this charge may also include the cost of any modifications of "IN" Metering required to accommodate the Generator. Final billing will be adjusted to actual costs upon completion of the work. The Company may charge replacement cost if the equipment installed is not new.

In addition to the one-time charge for metering equipment, a monthly operation and maintenance (O&M) charge shall be assessed on the installed value of the metering equipment required to provide the "OUT" Metering. This charge will vary if either the equipment or the O&M rate is modified. The carrying charge rate will be updated and become effective June 1st of each year pursuant to the ISONE OATT, Schedule 21-CMP, Schedule 13. There is also a monthly charge for recording and processing pulse data.

All metering equipment installed shall be owned and maintained by the Company.

K. Test and Calibration

The Company may test the metering equipment periodically. Tests are made in accordance with the Company's meter testing program (which complies with MPUC Chapter 320, ISO-NE Operating Procedure No.18 and applicable ANSI standards) and are typically scheduled annually. The Generator's representatives may be present to witness such tests.

L. Grandfathering Existing Metering

Certain existing metering arrangements which do not fully comply with the requirements above may be "grandfathered" as acceptable. Such arrangements must be approved by the Company and include the following:

- Metering of gross generator output and station service, in lieu of, interconnection-point metering.
- No measurement of kVARh "OUT."
- Ownership and maintenance of CT's and VT's by the Generator, i.e., metering other than interconnection-point where CT's and VT's are shared by the Company and the Generator.

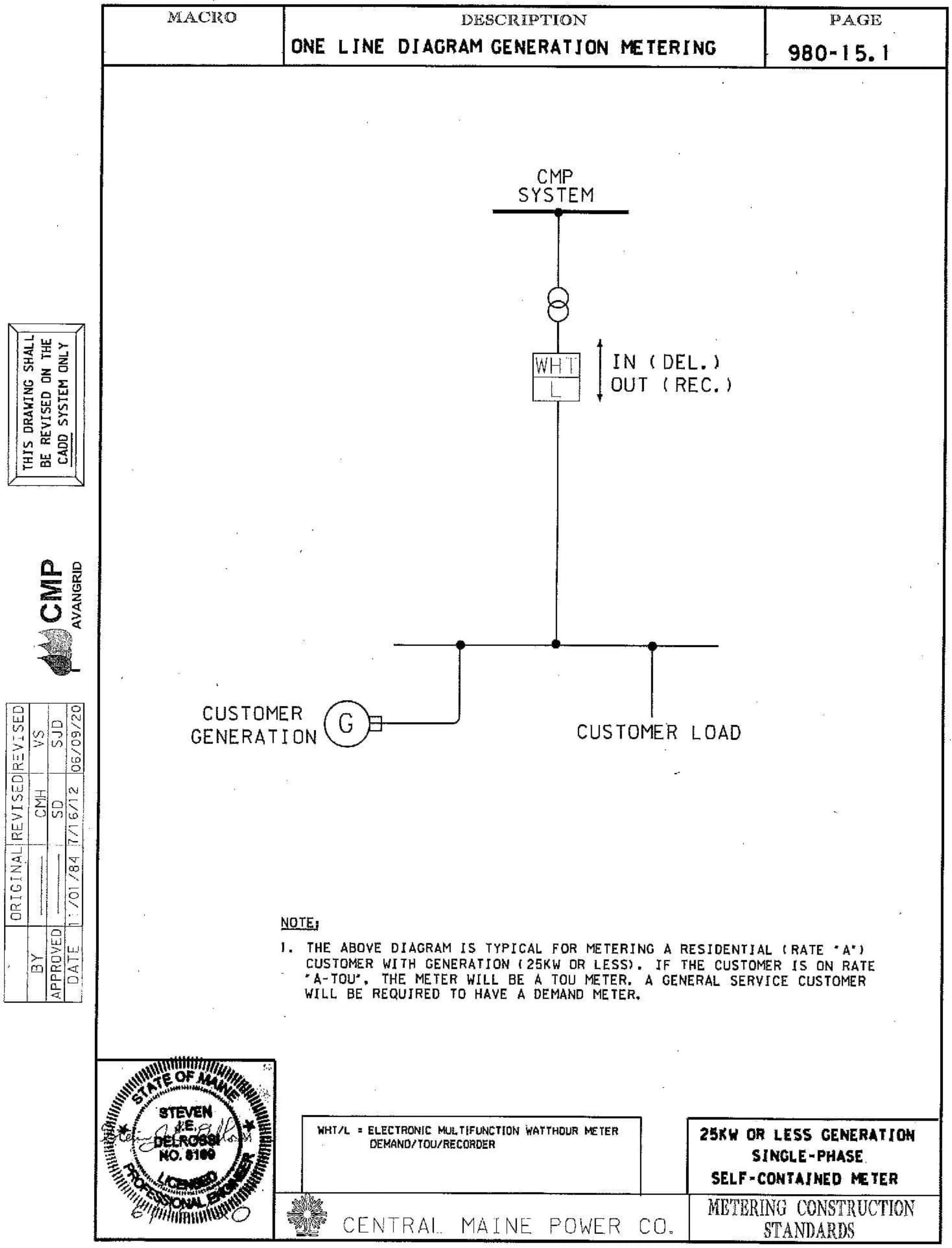
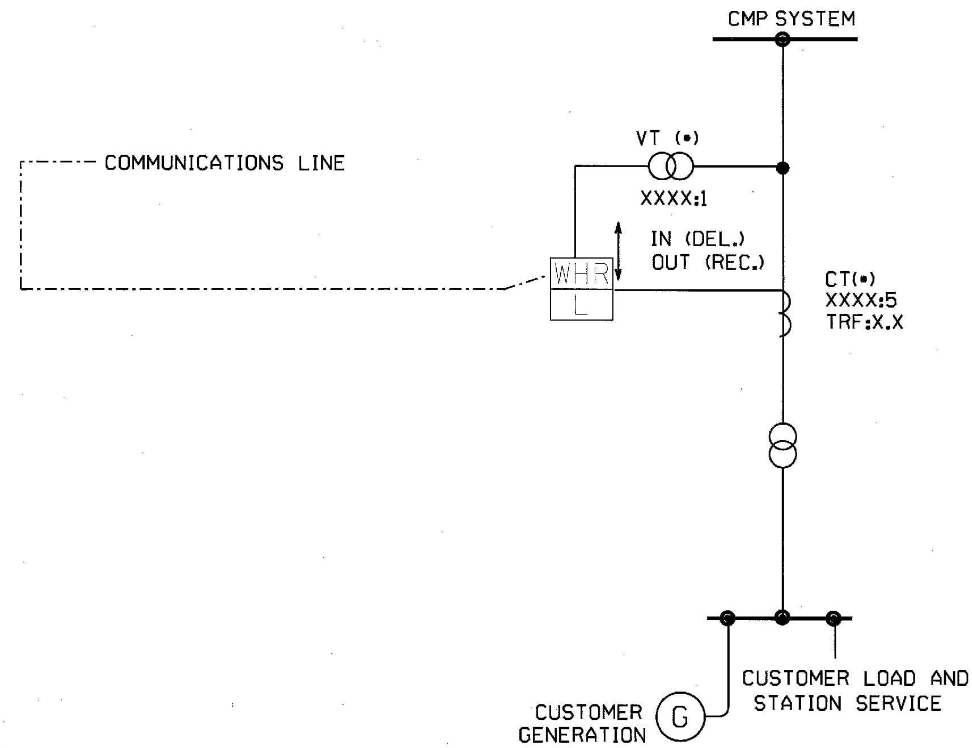


Figure IV-1: Metering: 25 kW or Less Single-Phase Generation

MACRO	DESCRIPTION	PAGE
	ONE LINE DIAGRAM GENERATION METERING	980-15.5



NOTE:

1. The above diagram is typical for metering a general service (Rate "MGS", "IGS", OR "LGS") customer with generation with the point of delivery on the high side of the generator step up transformer.

2. Tariff rate and DG rate require separate metered service for generation with communications line. Generation selling power to the ISO NE market require a communications line.

WHR/L = ELECTRONIC MULTIFUNCTION 4 QUADRANT METER WITH INTEGRAL RECORDER/DNP OUTPUT AND MODEM
(*) = (2) CT & (2) VT FOR 3 PH 3W METERING
(3) CT & (3) VT FOR 3 PH 4W WYE METERING
CT = CURRENT TRANSFORMERS
VT = VOLTAGE TRANSFORMER

STATE OF MAINE
STEVEN J.E. DELROSSI
NO. 8199
LICENSED PROFESSIONAL ENGINEER

GENERATION
TRANSFORMER-RATED METERS

CENTRAL MAINE POWER CO.

METERING CONSTRUCTION STANDARDS

THIS DRAWING SHALL BE REVISED ON THE CADD SYSTEM ONLY

CMP AVANGRID

	ORIGINAL	REVISED	REVISED
BY	CMH	VS	VS
APPROVED	SD	SJD	SJD
DATE	7-16-12	06/09/20	01/11/21

Figure IV-2: Metering: Generation Transformer-Rated Meter

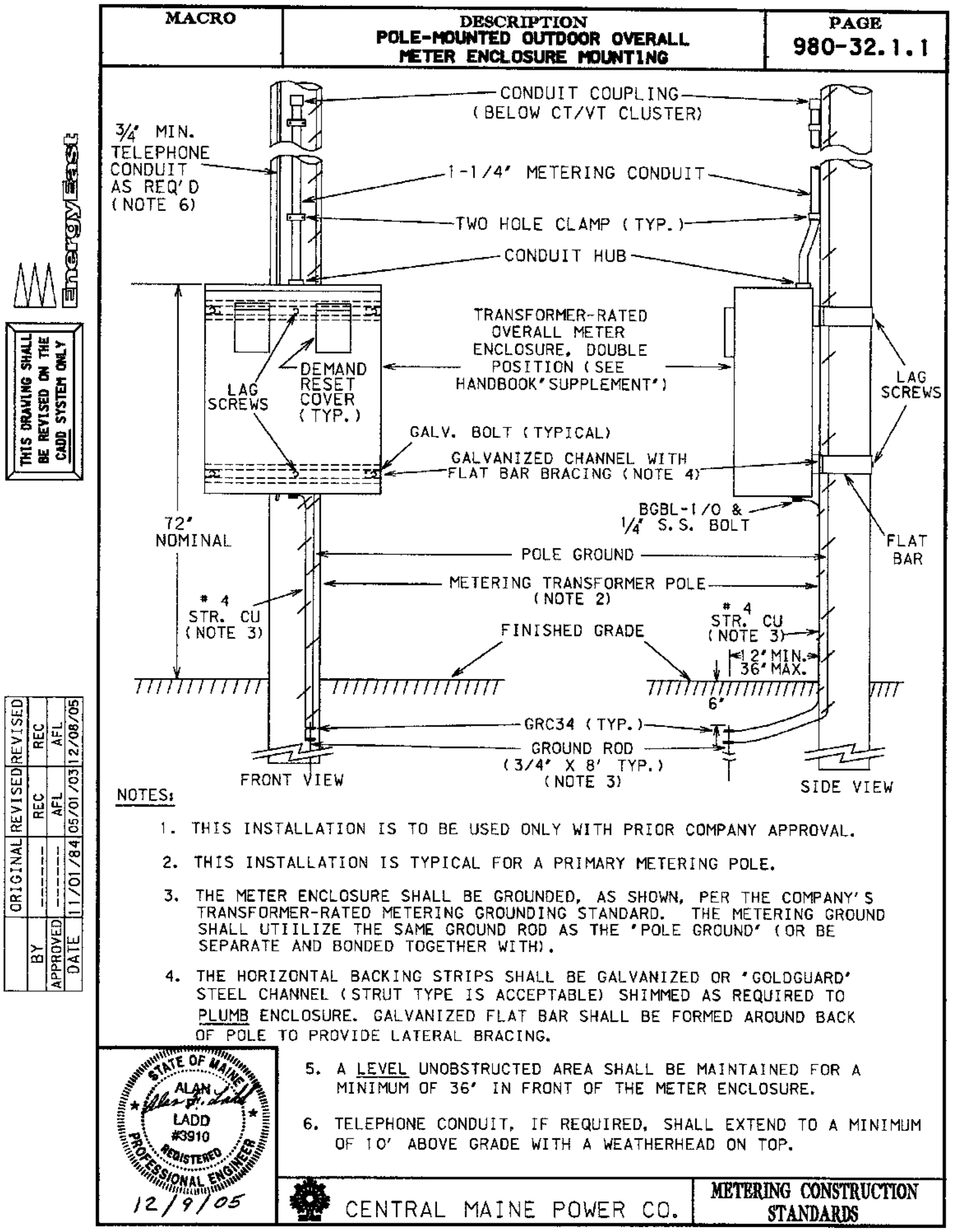
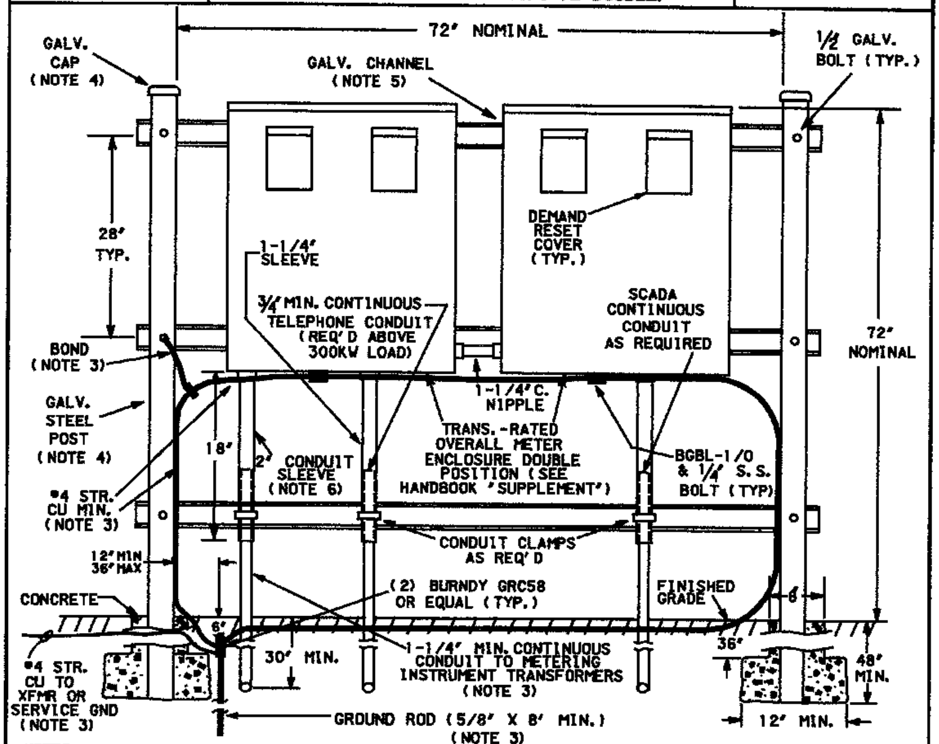


Figure IV-3: Pole Mounted Meter Enclosure Mounting.

MACRO	DESCRIPTION UNDERGROUND OUTDOOR OVERALL METER ENCLOSURE MOUNTING (2-DOUBLE)	PAGE 980-32.3.1



	ORIGINAL	REVISED	REVISED
BY	------	REC	REC
APPROVED	------	AFL	DEG
DATE	11/01/84	05/01/03	01/29/07

NOTES:

1. THIS INSTALLATION IS TO BE USED ONLY WITH PRIOR COMPANY APPROVAL.
2. A MINIMUM OF 24' CLEARANCE IS REQUIRED BETWEEN THIS METERING STRUCTURE AND A PADMOUNT TRANSFORMER FOUNDATION. A MINIMUM OF 15' CLEARANCE IS REQUIRED BETWEEN THIS METERING STRUCTURE AND A CMP POLE.
3. METALLIC CONDUIT AND ENCLOSURES SHALL BE BONDED AND GROUNDED PER 'HANDBOOK' SECTION VII AND NEC ARTICLE 250. ADDITIONALLY, THE METER ENCLOSURE SHALL BE GROUNDED, AS SHOWN, PER THE COMPANY'S TRANSFORMER-RATED METERING GROUNDING STANDARD. BONDING TO THE TRANSFORMER OR SERVICE GROUND FOR ALL CT ONLY (NO VTS) INSTALLATIONS: AS WELL AS, BONDING TO ANY OTHER NEARBY GROUNDING SYSTEM, IS REQUIRED.
4. THE POSTS SHALL BE 2-1/2" GALVANIZED STEEL PIPE WITH GALVANIZED STEEL CAPS OR 3" X 3" GALVANIZED STEEL ANGLE (OR EQUIVALENT) SET IN CONCRETE AS SHOWN (LARGER FOOTING TO PREVENT FROST HEAVE). PRESSURE TREATED 6" X 6" POST MAY BE SUBSTITUTED FOR STEEL ANHGLE OR PIPE, PROVIDED THEY ARE ANCHORED IN THE CONCRETE WITH BOLTS OR SPIKES.
5. THE HORIZONTAL FRAMING SHALL BE 1-5/8" X 1-5/8" 12 GA. MIN. GALVANIZED OR 'GOLDGUARD' (OR EQUIVALENT) STEEL CHANNEL (STRUT TYPE IS ACCEPTABLE) MOUNTED TO THE BACK OF THE POST. PRESSURE TREATED WOOD 4" X 4" MAY BE SUBSTITUED FOR STEEL CHANNEL HORIZONTAL FRAMING. SHIM AS REQUIRED TO PLUMB ENCLOSURE.
6. A PVC CONDUIT SLIP JOINT (AS SHOWN) OR A 'LISTED' STEEL EXPANSION JOINT SHALL BE PROVIDED. IF PVC IS USED, SCH. 80 IS REQUIRED WHEREVER SUBJECT TO PHYSICAL DAMAGE.
7. A LEVEL UNOBSTRUCTED AREA SHALL BE MAINTAINED FOR A MINIMUM OF 36" IN FRONT OF THE METER ENCLOSURE.

STATE OF MAINE DAVID GREENACRE NO. 10664 LICENSED PROFESSIONAL ENGINEER
1-31-07

CENTRAL MAINE POWER CO. | METERING CONSTRUCTION STANDARDS

Figure IV-4: Underground Meter Enclosure Mounting.

V. Supervisory Control and Data Acquisition

In order to facilitate safe, efficient and reliable operation of the EPS, any Generator with a rating of 1,000 kW or greater shall provide/have telemetry equipment compatible with the Company's Energy Management System (EMS). The Generator shall be responsible for all design, installation and ongoing maintenance and all associated costs and expenses incurred in connection with this telemetry equipment. The Company employs Supervisory Control and Data Acquisition (SCADA) to control and monitor the status of the EPS. This SCADA/EMS system provides real time status of the EPS and its components by collecting information from each installation via a Remote Terminal Unit (RTU). The RTUs are interconnected by data communications facilities to the Company's Primary and Back-up SCADA EMS computers. The SCADA EMS computers are used by Energy Control Center personnel who are responsible for power system operation and for interfacing with the ISO-NE.

For installations of 5,000 kW and greater, the Generator is obligated to meet not only the requirements specified in this document but also the requirements documented by ISO-NE's OP18 Metering and Telemetering Criteria Operating Procedure.

A. RTU Requirements

DNP3 shall be the communications protocol with SCADA RTU equipment. Communication equipment design and procurement must be reviewed by the Company to ensure this compatibility.

SCADA data provisions shall not be sourced from the "metering" discussed in Section IV. Metering section of this document. The source of the SCADA data shall be sourced by the Generator's RTU device(s).

The RTU and Communication power supply requirements shall meet, as a minimum, the following requirements:

1. The equipment shall **not** be dependent on a single ac power source. The power source shall be a station battery or an uninterruptible power source capable of supporting the anticipated load for at least eight hours.

   - Communication only facilities (terminal or intermediate) shall have a battery rated for at least eight (8) hours and a suitable backup power source for extended periods.

   - This includes telephone company equipment co-located with MP or DE equipment.

2. The equipment shall be capable of operating in a temperature range of -20°C to +50 °C for equipment within the control building or -40 °C to +50 °C for equipment installed in other outdoor enclosures. This temperature range is based upon the conditions that could exist when the ac power source is lost and as a result, air conditioning or heating is lost.

Any required maintenance or repair on the RTU and/or Communication equipment must be completed expeditiously to return the RTU to continuous operation.

B. Normal SCADA Point Requirements

Generators that are required to install an RTU shall provide for the following telemetry.

1. Analog Data (typically for each generating unit but the following quantities may be based on a composite of multiple generator units based on the size, type and configuration of the Generator’s facility. This shall be determined by the Company and the Generator shall be informed accordingly of this requirement)
   - Unit Terminal Gross Real Power (Megawatts)
   - Unit Terminal Gross Reactive Power (Megavars)
   - Unit Terminal Voltage (Kilovolts) if equal or greater than 2 kV
   - POI Voltage (Kilovolts)
2. Accumulator Data (for each generating unit with top of the hour reset)
   - Unit Net Hourly Energy Output (Megawatthours)
   - Unit Net Hourly Energy Input (Megawatthours) (where required)
3. Digital Data (for each generating unit)
   - Open/Closed Status of the Generator Circuit Breaker and the status of any additional circuit breaker(s) that is in series between the Generator and the POI
   - Breaker (Recloser) Remote/Local Switch status on the High Side Interrupting device
4. Data Scanning & Update Periodicities

   The following are required scan rates for scanning the data quantities indicated:
   - Analog data: scan every ten seconds.
   - Digital data: scan every two seconds.
   - Accumulator data: scan once every top of the hour with a reset

C. Additional SCADA Point Requirements

The Company, at its discretion, may require the following data quantities, measured at the Point of Interconnection with the EPS, in addition to or in lieu of the quantities listed in Section V.B:

1. Analog Data
   - GSU Low Side Net Real Power (Megawatts)
   - GSU Low Side Net Reactive Power (Megavars)
   - GSU High Side Net Real Power (Megawatts)
   - GSU High Side Net Reactive Power (Megavars)
   - Station Service Load Real Power (Megawatts)

- Station Service Load Reactive Power (Megavars)
- Frequency (Hz)
- Power Factor (PF)
- Line Current (Amperes)

2. Digital Data
   - Automatic Voltage Regulation (AVR) Status
   - Power System Stabilizer (PSS) Status
3. Other Data
   - Miscellaneous alarms (if any) associated with protective relay and communication equipment considered vital to the protection of the transmission system. (Examples: "Loss of Transfer Trip Guard Tone," "Power Line Carrier Checkback Failure," and "Loss of Protective Relay DC.") These points, if required, will be discussed between the Company and the Generator at or before the required SCADA RTU point list is submitted by the Generator.
   - The Company reserves the right to require other data, not listed in these requirements, if deemed necessary to support the reliability of the EPS. These other requirements will be determined on a case-by-case basis.

D. SCADA Control Point Requirements

For Distribution System interconnections requiring an RTU, the Generator will be responsible for providing the Company with remote SCADA control of the High Side Interrupting device in the event the Company may need to isolate the interconnection from the EPS on an emergency basis.

Examples of when this may occur include, but are not limited to the following: storm restoration, motor vehicle accidents and other emergencies, hot work, black start events, etc.

The control points required by the Company are as follows:

- Breaker (Recloser) Open
- Breaker (Recloser) Close

The Company, at its discretion and based on the Generator's settings/design, may require additional control points that it deems necessary for the safe and reliable operation of the EPS in all situations that may arise.

E. SCADA Communication Requirements

The Generator is responsible for the cost to install and maintain two continuous SCADA communications circuits. Depending on the type of circuit employed, this may be accomplished using two virtual circuits over one physical circuit. The first shall be between the Company's Primary SCADA/EMS computer in Augusta, Maine and the generation facility. The second shall be between the Company's Back-Up SCADA/EMS computer in Fairfield, Maine and the generation facility. Data can be transmitted via a telephone company provided circuit or via a private communications carrier. In some circumstances, the utility Data Communications Network may be utilized for a fee to provide the connection to the Company Control Centers, as noted above. The Company reserves the right to approve or disapprove of this latter option on a case-by-case basis.

1. Circuit Requirements

   The required communications protocol for SCADA is DNP3. The preferred method of delivery is via a TCP/IP circuit; however, a serial data circuit is also acceptable. The Company requires encryption of IP-based SCADA data.

2. Maintenance

   All Generation facilities with AGC are required to have 7 days-per-week, 24 hours-per-day repair capability for all SCADA circuits. All non-AGC generation facilities will undertake to effect SCADA circuit repairs as soon as reasonably possible in a time period negotiated with the System Operator.

F. SCADA Point Listing & RTU Configuration Data Schedule Requirements

The Company requires that any and all SCADA Point Listing(s) and RTU Configuration data be submitted to the Company for review and approval no later than forty-five (45) Calendar Days prior to the projected energization date of any new facility interconnection and no later than fifteen (15) Calendar Days for any subsequent SCADA or Communication changes associated with an existing interconnected facility. The Generator Owner shall be responsible for coordinating with the Company's EMS representative(s) all SCADA data collections and Communication additions or modifications thereto.

G. SCADA Communications, RTU and Data Point Commissioning Requirements

The Generator Owner shall coordinate, with the Company, a date(s) for commissioning the Generator's communication circuit, RTU and SCADA data points and shall provide notice, to the Company, of the requested commissioning date(s) 20 business days prior to the initial requested date(s).

All SCADA communications, RTU and associated data, and control points shall be fully commissioned before any Test or Operational power is produced onto the EPS.

VI. Safety

The interconnection of multiple generation facilities (controlled by many independent companies) on the Electric Power System (EPS) introduces additional safety concerns and the need for good communications between the Company and all Generators. This also requires that additional steps be added to the Company's work procedures for all feeders known to supply interconnected generation facilities.

A. Switching and Tagging

Strict adherence to established Switching, Tagging and Grounding procedures must be maintained for the safety and protection of all personnel. All switching operations of the Dispatch Point of Demarcation / DP device at the Generator's site will be performed in accordance with the Company's Switching and Tagging Procedures. The Company will secure the device in the appropriate position (open or closed) based upon EPS work and personnel protection requirements.

The Generator will provide the CMP Supervisor-Dispatch & Energy Control Center (ECC) an Authorized Switch Person list of all Generator personnel trained and qualified to perform switching on the DP device. This list will be certified and maintained by the Generator and shall be updated annually or when changes to this list occur. Qualified Generator personnel who are on the list may operate Generator-owned DP devices, under the jurisdiction of Energy Control Center, based on Company or Generator requirements. This provision is made to allow the Generator to comply with Occupational Safety and Health (OSHA) requirements for deenergizing lines and equipment for employee protection. Should the Generator not have anyone qualified to operate the DP, the Generator will provide a list of personnel with Controlling Authority that are knowledgeable about the status of the Generator's equipment connected to the EPS. This must be someone who will take responsibility for the status of the equipment and give the Company authority to energize. These Generator Authorized Switch Person and personnel with Controlling Authority lists must be provided to the CMP Supervisor-Dispatch & ECC as above and are the only people that are authorized to contact Energy Control Center to discuss operations of the DP. Generator personnel not on the switch and tag list will not be allowed to operate the DP device under jurisdiction of the Energy Control Center.

During the construction phase (prior to commercial operation), the developer shall provide a list of contacts who meets the Company requirements as outlined in this section to take responsibility for switching and tagging at the Demarcation Point at the time of energization.

B. Company Responsibility

When the Company is required to work on a Generator's premises, an inspection of the work area will be made by Company representatives. If the Company believes that hazardous working conditions exist, the Generator will be required to correct the unsafe condition before the Company will commence work.

C. Generator Responsibility

The Generator is responsible for establishing a program to comply with all required safety regulations for protection of personnel.

1. Switch Operation

When taking facilities out of service or when requesting switching, the CMP Transmission Coordinator must receive a notification request for operation of the DP device or DP maintenance. For transmission lines 69 kV and above the notification must be received 120 days in advance or upon receipt of ISO approval of the outage, whichever comes first. Below 69 kV, the notification must be received 30 days in advance or upon receipt of ISO approval of the outage, whichever comes first. The notification is made by emailing group.cmptranscoord@cmpco.com.

- Switching for Company personnel: Switching orders will be issued to Company personnel. Company personnel will either operate or observe the proper operation of the DP device. Company personnel will then lock and tag the device. Company personnel will take all Holds and Clearances.
- Switching for Generator personnel: Energy Control Center will issue switching orders for the Generator Authorized Switch Person to operate the device. Authorized Generator personnel will lock and tag the device with Company tags. Generator personnel will take all Holds and Clearances for Generator-required work on the Generator's side of the device.
- The Generator may request that Company personnel perform the switching. After the Company has operated, locked, and tagged the device, Generator personnel will add their own locks, and, if applicable, tags. Generator personnel with Controlling Authority listed per A. above, will take all Holds and Clearances. All locks and tags added by Generator personnel must be properly cleared before the Company will clear the lock, operate the device, and lock it in the appropriate position.

2. Working on De-energized Equipment

It is the Generator's responsibility to ensure that the equipment served by an open device is actually deenergized. This equipment must be tested for voltage, using appropriate techniques, to ensure deenerization.

3. Switch Access

The Generator must provide the Company unrestricted, continuous access to the Dispatch Point of Demarcation / DP Device. If this device is located inside a Generator's facility, such as a substation, then that facility must be dual locked by the Generator and the Company in a manner such that opening either lock will enable access to that facility.

D. Deenergized Circuits

The Generator shall **not** energize a deenergized T&D circuit unless the generation facility is black start capable. This black start capability must be verified by the Company and the generation facility must be acting under the direct authorization of a System Operator for a generator to energize a deenergized circuit. See Section II.F.4, "Islanded Generation Limits."

VII. Operations and Maintenance

Power consumers are affected by the Generator's operation and maintenance practices. Practices that promote high reliability will enhance the quality of service to all customers on the EPS.

ISO-NE coordinates and approves facility outages in accordance with the ISO-NE Operating Documents, see Footnote 4, applicable reliability standards, or successor documents. Each party may in accordance with the ISO-NE Operating Documents, Applicable Reliability Standards, or successor documents, in coordination with the other Party(ies), remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other party(ies') facilities as necessary to perform maintenance or testing or to install or replace equipment, subject to the oversight of System Operator in accordance with the ISO-NE Operating Documents, in accordance with the site-specific agreement, ISO-NE Operating Documents, applicable reliability standards, or successor documents.

The Generator is responsible for coordinating outages with the Company and with ISO-NE. They must be in compliance with the Company and ISO-NE outage coordination procedures and scheduling lead times at all times. Adherence to these procedures is critical to maintaining the transmission system reliability and reducing congestion and contingency exposure. See Generator Interfacing Sections 3 and 4 for outage application information.

A. Generator Interfacing

There are many events that will necessitate communications between the Company and the Generator. The Company and the Generator will provide each other a contact name, phone number, address, and Email addresses, for the purpose of conducting ongoing business.

1. Trouble Calls

Generators may call the Company trouble number for inquiries about utility power outages and other day-to-day problems, 1-800-696-1000. Requests for the Company to open/close the Generator's DP Switch should be made to the Company as indicated in Section VI, "Safety," of this document.

2. Metering

The metering package at the Generator's facility will be on a regular calibration schedule which is coordinated by Company Metering Services. This department will attempt to contact the Generator prior to actually calibrating these meters. The Generator can observe this procedure if desired.

3. Line Outages

The generator is responsible for coordinating all line outages 69 kV and above with the Company (CMP) transmission coordinator 120 days in advance or upon receipt of ISO-NE approval of the outage, whichever comes first. Below 69 kV, the notification must be received 30 days in advance or upon receipt of ISO-NE approval of the outage, whichever comes first. Notification is made by emailing group.CMPtranscoord@cmpco.com.

Footnote 4. ISO-NE provides operating procedures to Market Participants for the Regional Transmission Organization and the region's bulk electric power system. The procedures inform generators of operating and reliability requirements.

4. High Speed Protection Outages

For generators with high speed protection schemes (I.E. POTT/BFTT and or 87L) communicating with the Company via a fiber optic cable, the Generator is responsible for coordinating all High Speed Protection outages with the Company (CMP). Notification is made by emailing group.CMPtranscoord@cmpco.com.

B. Site Inspections

The following site inspections will be coordinated between the Generator and the Company.

1. Initial Inspection

The initial inspection includes the Generator's facility acceptance testing which must be conducted before the Generator will be allowed to generate in parallel with the EPS, as described in Section III.L, “Generator Facility Acceptance,” of this document. This inspection will also involve a discussion and observation of standard operation and safety procedures.

2. Annual Inspection

The Company will determine the necessity for an annual inspection. If conducted, it will include a visual inspection of the generator and switchgear rooms (where intertie equipment is located) and a review of operation and maintenance procedures, pertinent documentation, and adherence to all applicable codes and standards.

3. Biennial Test and Inspection

This test and inspection will occur every two years after the initial inspection for generators that are not registered with the NERC PRC-005-X Protection System Maintenance Plan, see footnote 5. Items of concern for the annual inspection will be reviewed and a test of the intertie system will be performed per Section VII.E.1, “Intertie Protection System.” This test will include input verification testing, overall protection system operability, and calibration of protective relays. Input verification testing will include verification of VT and CT circuits, transformer ratios, and DC trip source availability. The overall protection system operability will entail verification of trip circuits including a trip test of each breaker tripped by the intertie relaying. Calibration of relays will verify the setpoints and confirm the ability of the protective devices to respond within specified parameters.

Protective Intertie Relay calibration testing must be performed by a qualified contractor. Verification of setpoints will be in accordance with Company specifications. Please note, if you are a generator connected to the Company by a high speed protection scheme (i.e. POTT/BFTT and/or 87L via a fiber optic cable), each protective system must be taken out of service one at a time through the Company application process during the test and inspection. If not, during the test and inspection, the Company will be impacted even if the generator is isolated by an open switch or circuit breaker from the Company. See the Generator Interfacing section.

Footnote 5. If the generator is registered with NERC, then the testing intervals for relays, lockout relays, trip paths and circuit breakers will be moved from a biennial basis to every six years. However, a site inspection will still be required on a biennial basis. A two (2) year site inspection will include monitoring of the relays PT’s and CT’s secondary systems, print checking for any wiring changes, visual confirmation of settings on electromechanical relays, perform COMPARE settings on microprocessor relays, relay cabinet inspection, and verification that maintenance is being performed on breakers, battery systems, etc..

C. Site Access

The Company will require site access for the following reasons:

1. Routine Access

The Company will require access to the Generator's facilities to perform the inspections and tests detailed in this document as well as for other business needs. Normally, this access will be coordinated and scheduled by phone to enable each party to conduct the necessary business with minimum impact to the other party.

2. Emergency Access

The Company will require unrestricted access to the Dispatch Point of Demarcation / DP Switch per Section VII.C.3, “Switch Access,” of this document. In an emergency situation, it may be necessary for the Generator's facility to be disconnected from the T&D system.

- If the Generator's site is manned and time permits, the Company will request the plant operator to reduce generation then trip the generator(s) off-line in accordance with standard operating procedures. Qualified Company or Generator personnel will then open the Generator's DP Switch using the Company’s switching procedures.
- If the Generator's site is **not** manned or time does **not** permit, the Company will open the DP Switch using the Company’s switching procedures. Should the Generator discover that the site has been disconnected from the T&D system, the Generator may call the Company’s Energy Control Center for information.

3. Construction Access

In general, construction of required interconnection upgrades cannot begin until Company site access is provided and all staked locations are agreed to (access road, pole locations, etc.)

D. Operational Requirements

Utility T&D systems are designed to provide safe, reliable service to all customers. Generators operating in parallel with the T&D system must not operate in a manner which results in unacceptable service to customers. Generators whose operation of equipment results in unacceptable service to customers or adversely affects the T&D system must immediately correct any problems by performing modifications to equipment as necessary to prevent the recurrence of those problems. If necessary, the Company will discontinue the facility interconnection service until the problems have been corrected.

During maintenance, testing, or repair of T&D facilities, the Company may request the Generator to discontinue parallel operations. Such maintenance may require opening of the tie disconnect switch.

The Generator shall maintain satisfactory operating communications with the System Operator and the Company in accordance with applicable provisions of ISO-NE Operating Documents, applicable reliability standards, or successor documents.

The following operating requirements are necessary to ensure reliable service and that the operation of generation equipment does not cause any adverse effects on the T&D system.

1. Voltage Control

   The Generator must automatically adjust generation to maintain adequate voltage regulation to maintain its voltage schedule, (Schedule J of the IA if applicable), and be in accordance with ISO-NE Operating Procedure #12 and Master / Local Control Center #8. The distribution voltage to all customers must be maintained within $\pm$5% of nominal voltage as specified by the Maine Public Utility Commission Chapter 320 Rules, Service Standards for Electric Utilities. The Generator must employ an automatic method of disconnecting generation equipment from the T&D system if the system voltage cannot be maintained within tolerance.

2. Reactive Power

   To prevent the degradation of system voltage to the Company's customers as a result of interconnection with a Generator's facility, Generators with synchronous generators shall generate such reactive power as may be reasonably necessary to maintain voltage levels and reactive area support.

3. System Performance Reporting

   For the Company to adequately assess the performance of its system, ensure compliance with regulatory requirements, and provide conformance reporting to NPCC and the ISO-NE, Generators will be required to submit the following operational information:

   - Continuously (Units 1,000 kW or larger): Accurate and reliable metering and information regarding status and the output (MW, MVAR, kV, MWh, and alarms) of the Generator's facility as specified in Section V, "Supervisory Control and Data Acquisition."
   - When Available: Information about whether the facility has capability for participation in system restoration or has black start capability.
   - Each Year or as Required: Maintenance schedules for the generator, step-up transformer, tie breaker, and protection system.
   - Biennially: Setpoint verification on all underfrequency/overfrequency relays or underspeed/overspeed devices which are not part of the Intertie Protection Equipment.

   After Outages or Relay Operations: Information about any outage or intertie relay operation involving their facility as per Company instructions for Relay Operation Target Report within two (2) working days. (See the sample report, Figure VII-1, and associated instructions, Figure VII-2, at the end of this chapter.) Blank reports are available through the Company.

4. Voltage and Frequency Trip Settings, Voltage and Frequency Ride- Through, and Grid Support

For inverter based equipment, the equipment must meet the requirements of the Inverter Source Requirement Document of ISO-NE.

E. Testing & Maintenance

The Generator will have full responsibility for the routine testing and maintenance of the interconnection equipment, including the Intertie Protection System, the Generator Protection System, the Unit Step-up Transformer, the Intertie Circuit Breaker, and the Station Battery and Charging System. The Company will monitor maintenance on the Intertie Equipment, including protection system(s), transformer(s), Intertie Circuit Breaker(s), and Station Battery(ies) and Charging System(s), etc.

The Company is primarily interested in the performance of the total facility to ensure that the facility operates with no adverse impact to the T&D system. Therefore, the Generator Owner is expected to maintain the generator and all of its support systems. The Generator is also responsible for tree trimming and vegetation control in accordance with Company vegetation control standards for any portion of the intertie where a fault could affect the operation of the Company's T&D system.

As a minimum, Generators must perform all periodic maintenance and testing according to: the recommended manufacturer's maintenance and test guidelines; the requirements specified in this document; and specifications found in reference documentation of controlling authorities.

Maintenance records are required to be maintained and must be made available to the Company during the annual inspections and biennial test and inspections. Specific equipment test data must be made available to the Company upon request to provide evidence that the equipment will operate as intended. Failure of the Generator to provide proper testing and maintenance will result in the Generator being notified and requested to take prompt corrective action within ten (10) days. Should the Generator then fail to provide the proper testing and maintenance, the Company will discontinue the facility interconnection service until appropriate corrective action is taken and Company approval is obtained.

If the interconnection equipment is not properly maintained, fails to perform its intended function, or has been modified from that approved by the Company, then the Company will give notice to correct the area of noncompliance or will open the interconnection. The time allowed for the Generator to comply, while remaining on line, will depend upon the Company's assessment of the safety, reliability, and performance issues relating to the noncompliance.

The Company may inspect any of the intertie equipment, including the protection systems, whenever such an inspection is deemed necessary by the Company. This inspection may include tripping of the intertie and/or generator circuit breaker(s). The Generator shall bear the cost of any necessary testing that may be requested by the Company.

All outage schedules and maintenance work will be coordinated through the Company.

The Generator must implement a maintenance program consistent with acceptable industry practice so as to achieve a highly reliable interconnection. During site visits, Company representatives will be interested in checking maintenance records and performing testing as follows:

1. Intertie Protection System

   The Generator must perform a relay calibration test every two (2) years using equipment of known accuracy unless the generator is registered with the NERC PRC-005-X Protection System Maintenance plan, see Footnote 5. This biennial test shall include calibration and operational tests of individual relays and functional tests of the subsystems and the total system. Calibration checks will include verification of setpoints and voltage and current measurements. Operational and functional tests will include as many trips of the tie and/or generator breaker(s) as necessary, a synchronizing test, and any other test as may be required by the Company. Transfer trip equipment, where installed, will also be tested. During the biennial operational test, up-to-date design drawings must be made available to Company personnel to allow for safe, reliable testing of the facility.

2. Intertie Circuit Breakers/Reclosers and Transformers

   The Generator will perform maintenance on these devices at a maximum interval not to exceed twenty-four (24) months. The Generator must provide to the Company the identity and qualifications of the personnel who perform this maintenance and any associated testing. This maintenance must be coordinated with Energy Control Center to obtain the proper zones of clearance.

3. Station Battery and Charging System

   Batteries associated with the Intertie Protection System must have a high degree of reliability. To ensure that the Intertie Protection System performs its intended function, the Generator must implement a battery preventative maintenance (PM) program to include periodic battery inspections and testing as approved by the Company. The reports from these battery inspections and tests shall be maintained by the Generator and made available for review by Company personnel during the periodic tests and inspections of the facility and at other times as requested by the Company.

   - Battery Inspections per IEEE Std 450-2002 and IEEE Std 1188-1996

     The Monthly PM program will include the following:

     a) Float voltage measured at battery terminals.

     b) General appearance and cleanliness of the battery, the battery rack and/or battery cabinet, and the battery area.

     c) Charger output current and voltage.

     d) Electrolyte levels (where applicable).

     e) Cracks in cells or evidence of electrolyte leakage.

     f) Any evidence of corrosion at terminals, connectors, racks, or cabinets.

     g) Ambient temperature and ventilation.

     h) Pilot-cells voltage and electrolyte (where applicable) temperature.

     i) Battery float charging current or pilot cell specific gravity (where applicable).

j) Unintentional battery grounds.

k) All battery monitoring systems are operational, if installed.

The Quarterly PM Program will include the following:

a) Voltage of each cell.

b) Specific gravity (where applicable) of 10% of the cells of the battery if battery float charging current is not used to monitor state of charge.

c) Electrolyte temperature (where applicable) of 10% or more of the battery cells.

d) Cell unit internal ohmic values (for VRLA batteries only).

e) The Yearly PM Program will include the following:

a) Specific gravity (where applicable) and temperature of each cell.

b) Cell condition. This involves a detailed visual inspection.

c) Cell-to-cell and terminal connection resistance.

d) Structural integrity of the battery rack and/or cabinet.

e) Cell unit internal ohmic values (for VRLA batteries only).

A sample form for recording this information is included as Figure VII-3 at the end of this section.

f) With charger on, check all individual cell voltages (if bank consists of 3 cell units, check the voltage of all 3 cells.)

A sample form for recording this information is included as Figure VII-3 at the end of this section.

A high-rate charge will be performed as required, or battery cells replaced, if the cells aren't within the manufacturer's recommendations or applicable IEEE Standards, or if a trend of reduced cell voltage is detected. Where inspection data is incomplete or indicates battery deterioration or improper maintenance, the Company will require the completion of a battery capacity test or replacement of the battery.

During the biennial test and inspection, the Generator may be required to perform a battery inspection in the presence of the Company's representative. The results of this inspection will be reviewed by the Company for compliance with this station battery PM requirement.

- Battery Testing: The Generator must perform a battery capacity (load-discharge) test on the station battery that provides tripping power for the Intertie Protection System. This capacity (load discharge) test must prove that the station battery retains at least 80% of its rated capacity. If the capacity falls below 80%, the battery must be replaced. An initial battery capacity test shall be done prior to battery installation and commissioning. For flooded cells, additional capacity tests will be done at least every five years during the battery's operational life, in accordance with the latest applicable IEEE Standards and manufacturer's specifications. For VRLA batteries, capacity tests will be performed on an annual basis during the battery's operational life.

DC internal cell resistance testing, as approved by the Company on a case-by-case basis, may be temporarily used as an alternative to capacity testing. This approval would only take place if assurances were made that the battery would be capacity tested in an acceptable time period to the Company. To obtain approval for load testing, the Generator will supply the Company with a proposed battery test program certified by a professional engineer. The professional engineer must certify that the battery test program will yield test results that reliably indicate the battery has ample capacity to meet the needs of the generation facility.

Results of all station battery tests must be provided to the Company.

- Battery Charging: A normal float charge will be maintained on the battery and a high-rate (equalizing) charge will be performed periodically as recommended by the manufacturer or applicable IEEE standards. The battery must be cleaned and each cell must be appropriately and conspicuously marked with a cell number for reference. Where applicable, cell fluid levels must be maintained with appropriate replacement fluid, in accordance with manufacturer's recommendations.

F. Planning Standards

For facilities interconnected to the utility transmission system, the Generator is required to meet AVANGRID Transmission Planning Criteria; ISO-NE Planning Procedures; NPCC Criteria, Guides, and Procedures; NERC Planning and Compliance Standards; and FERC standards.

Central Maine Power **FAX (207) 623- 7380**
System Protection Department **(207) 623- 7305**
83 Edison Drive
Augusta, Maine 04336

SITE: ______________________________ DATE: ____/____/____

SUPERVISOR/OPERATOR: ______________________ PHONE: ______________

OPERATION REPORT FOR PROTECTIVE RELAYS

TRIPPED		RELAY ID NUMBER	TARGET	TIME CLOSED
DATE	TIME			

COMMENTS:

____
____
____
____
____
____

WEATHER CONDITIONS ON DATE OF EVENT - (Circle if known):

fair wind rain sleet snow thunder, lightning

other ______________________________

SPECIAL INSTRUCTIONS:

Fill out and FAX to the Company at the number listed above, or fold as indicated, attach first-class postage, and drop in the mail.

Figure VII-1: Relay Operation Target Report

The following instructions are a guide to using this relay operation target form and should answer the majority of Generator questions. Any additional questions can be addressed to the Company by contacting the Company System Protection group at (207) 623-3521, ext. 3505.

This form will be completed and forwarded, faxed, or Emailed to don.gurney@cmpco.com within 48 hours of a relay target operation, to: Central Maine Power Company, System Protection Department, 83 Edison Drive, Augusta, ME 04336, Fax No. (207) 623-7380.

Site: The name of the facility where the relay is located.

Date: The date the form is filled out. This is also the date the target is reset.

Inspector/ Operator: The person reporting the target drop.

Phone: The extension, or phone, where the Inspector/operator can be reached.

Time and Date tripped: The time when the device tripped. If unknown, and the station has SCADA capability, call Energy Control Center for the date of operation. If the station is not manned or tied to SCADA, write the date of the last station check under System disturbance details. This will indicate a time frame within which the event occurred.

Relay I.D. number: This is the Company identification number affixed to the relay. Report all relays indicating a trip flag.

Target letter: This indicates which element of the relay operated to trip the breaker.

> **T or I**: This indicates either a time delayed or instantaneous relay operation, which is usually displayed by a red flag.
>
> **LED**: This target letter is displayed by an LED next to a label indicating the target.
>
> **Phase Target**: This indicates which phases were faulted during the event. Typically displayed by a red flag.
>
> **Alpha-numeric**: This target display uses ANSI designations to indicate the type of fault that occurred. For example; 21Z1, 51N, ABC, AG etc.

Refer to the manufacturer's instruction book for instructions on retrieving target information from specific relays.

Time closed: The time the generation is brought back in parallel with the Company. If the date for re-energization is different than the trip date, add it in this column also.

Comments: In addition to the list on the form, indicate any information that may be relevant to the situation. For example: "wood crews were working in the area." Record information received from the Company in this section also.

Weather conditions on date of event: Circle or list the condition. If the weather condition was extreme, indicate this under “Other."

Figure VII-2: Instructions for Relay Operation Target Report

Location ___________ Make ______ Date _______ Pilot Cell # ______

No. of Cells ______ Type _______ Yr Mfd ______ Voltage _______

Batt Temp ____°F Normal Charging Current _______ Temp Corr. ________

Readings: o Corrected Positive to Ground _______ Negative to Ground ________
o Not Corrected

INDIVIDUAL CELL READINGS											
#	VOLTAGE	SPECIFIC GRAVITY/ CELL RES	FL**	#	VOLTAGE	SPECIFIC GRAVITY/ CELL RES	FL**	#	VOLTAGE	SPECIFIC GRAVITY/ CELL RES	FL**
1				21				41			
2				22				42			
3				23				43			
4				24				44			
5				25				45			
6				26				46			
7				27				47			
8				28				48			
9				29				49			
10				30				50			
11				31				51			
12				32				52			
13				33				53			
14				34				54			
15				35				55			
16				36				56			
17				37				57			
18				38				58			
19				39				59			
20				40				60			
REMARKS:											

* Monthly inspection is required only on the pilot cell. All cells must be inspected quarterly.

** Fluid Level: A check indicates fluid was added to a specific cell due to a low fluid level.

Taken by:________________________

Figure VII-3: Sample Station Battery Inspection Form

VIII. References

The references listed below will provide the Generator with a ready list of relevant technical standards and documents pertaining to the design, operation, and maintenance of a Generator's facility to be operated in parallel with an electric utility.

The Authoritative Dictionary of IEEE Standards Terms 7th Edition.*****

ANSI/IEEE Std. 450-2010, IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications.*****

ANSI/IEEE Std. 484-2002 (R2008), IEEE Recommended Practice for Installation Design and Installation of Lead-Acid Batteries for Stationary Applications.*****

ANSI/IEEE Std. 485-2010IEEE Recommended Practice for Sizing Large Lead-Acid Batteries for Stationary Applications.*****

ANSI/IEEE Std. 519-2014, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems.*****

ANSI/IEEE Std. 1106-2015, IEEE Recommended Practice for Installation, Maintenance, Testing, and Replacement of Vented Nickel-Cadmium Batteries for Stationary Applications.*****

ANSI/IEEE Std. 1188-2005, IEEE Recommended Practice for Maintenance, Testing, and Replacement of Valve-Regulated Lead-Acid (VRLA) Batteries for Stationary Applications.*

ANSI/IEEE Std. 1453-2004, IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems.*

ANSI/IEEE Std. 1547-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources and associated Electric Power Systems Interfaces*

ANSI/IEEE Std. 1547.1-2005, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.*

ANSI/IEEE C2-2017, National Electrical Safety Code.*****

ANSI/IEEE C37.90-2005, Standard for Relays and Relay Systems Associated with Electric Power Apparatus.*

ANSI/IEEE C37.95-2014, Guide for Protective Relaying of Utility-Consumer Interconnections.*****

ANSI/NFPA, National Electrical Code Handbook.

ISO-NE Inc Transmission; Market & Services Tariff Schedule 23 Standard Small Generator Interconnection Procedures (SGIP), (Applicable to Generating Facilities No Larger Than 20 MW).

ISO-NE Inc Transmission; Market & Services Tariff Schedule 22 Standard Large Generator Interconnection Procedures (LGIP), (Applicable to Generating Facilities That Exceed 20 MW).

Bulk Power System Criteria as specified by:

1. **ISO New England Criteria, Rules & Procedures,** see WWW.ISO-NE.COM.
2. **New England Power Coordinating Council (NPCC) Criteria,** see WWW.NPCC.ORG.

Central Maine Power Company Safety Rules & Regulations for Central Maine Power Company Contractors (12/11/2007).

AVANGRID Transmission and Distribution Planning Manuals – Criteria & Processes

ISO New England, Operating Procedures.

Central Maine Power Company, Substations Standards.

IEEE 88 THO224-6-PWR, Intertie Protection of Consumer-Owned Sources of Generation.*****

IEEE Paper F 80 258-4, IEEE Committee Report on Excitation System Models for Power System Stability Studies.*****

Maine Public Utilities Commission Chapter 320, Service Standards for Electric Utilities.

Maine Public Utilities Commission Chapter 304, Standards of Conduct for Transmission and Distribution Utilities and Affiliated Competitive Electricity Providers

Maine Public Utilities Commission Chapter 313, Customer Net Energy Billing

Maine Public Utilities Commission Chapter 315, Small Generator Aggregation.

Maine Public Utilities Commission Chapter 324, Small Generator Interconnection Procedures

ISO New England Operation Procedure No. 11, Black Start Capability Testing Requirements (10/13/2006)

North American Electric Reliability Council (NERC) & Western Electricity Coordinating Council, NERC/WECC Planning Standards (4/10/2003), see WWW.**NERC**.COM.

Northeast Power Coordinating Council (NPCC), Bulk Power Systems Protection Criteria, NPCC **Document A-5**, see WWW.NPCC.ORG

Inverter Source Requirement Document of ISO New England (ISO-NE)

UL 1741 SA Advanced inverters*IEEE information can be obtained from:

IEEE Operations Center
445 Hoes Lane,
Piscataway, N.J.08854-4141 USA
Phone: 1(732) 981 0060
Email: stds-info@ieee.org

Appendix 1

Energy Storage System (ESS) Application Requirements / System Operating Characteristics / Market Participation Application Requirements.

a) Provide a general overview / description and associated scope of work for the proposed project. Is the new ESS project associated with a new or existing Distributed Generation (DG) facility?

b) Identify whether this is a Stand-Alone or Hybrid ESS proposal, or a change to the operating characteristics of an existing system.

c) Indicate the type of Energy Storage (ES) technology to be used. For example, NaS, Dry Cell, PB-acid, Li-ion, vanadium flow, etc.

d) Indicate how the ESS will be charged and/or act as a load: (1) Electrical Grid Only, (2) Unrestricted charging from Electrical Grid and/or DG system, (3) Restricted charging from Electrical Grid and/or DG Systems, or (4) charging from DG only.

e) If the intended use case for the ESS includes behind-the-meter backup services, please provide a description and documentation illustrating how the entire system disconnects from utility during an outage (e.g. mechanical or electronic, coordination, etc.).

f) Provide the data sheet for the battery portion of the energy storage equipment. including the model, capacity (kWh), and manufacturer

g) Provide specification data/rating sheets including the manufacturer, model, and nameplate ratings (kW) of the inverter(s)/converters(s) for the energy storage and/or DG system.

h) Indicate any impacts of ambient temperatures on charging and discharging capabilities, specifically noting any restrictions on available capacity as a function of temperature and listed on the system facility's nameplate.

i) Provide details on cycling (anticipated maximum cycles before replacement), depth of discharge restrictions, and overall expected lifetime regarding the energy storage components.

j) Provide proposed inverter(s) power factor operating range and whether inverter(s) are single quadrant, two-quadrant, or four-quadrant operation.

k) Provide specification data/rating sheets including the manufacturer, model, and nameplate ratings (kW) of the inverter(s)/converters(s) for the energy storage and/or DG system.

l) Provide details on whether the inverter(s)/converter(s) have any intrinsic grid support functions, such as autonomous or interactive voltage and frequency support. If they do, please describe these functions and default settings.

m) Indicate whether the ES and DG system inverter(s)/converter(s) are DC-coupled or AC-coupled.

n) Indicate whether the interconnected inverters inverter(s)/converter(s) is/are compliant to the latest versions of the following additional standards. If partially compliant to subsections of the latest standards, please list those subsections: IEEE 1547a, UL 1741 and its supplement SA

o) If the interconnected inverter(s)/converters are not compliant with the previously listed additional standards, please describe show utility grade protection, relay and controls are implemented between your hardware and the utility.

p) Detail any integrated protection that is included in the interconnected inverter(s)/converters. For example, describing over/under-voltage/current frequency behavior and reconnection behavior would comply, such as solid state transfer switching or other.

System Operating Characteristics:

a) Identify the maximum nameplate rating in kW ac for each source (storage, any paired inverter-based distributed generation).

b) Identify the maximum net export and import of the Hybrid or Stand-Alone system in kW ac

c) Indicate the maximum ramp rates during charging and discharging.

d) Indicate the maximum frequency of change of operating modes (i.e. charging to discharging and vice-versa) that will be allowed based upon control system configurations

e) Indicate any specific and/or additional operational limitations that will be imposed (e.g. will not charge between 2-7pm on weekdays).

f) Provide a summary of protection and control scheme functionality and provide details of any integrated protection of control schematics and default settings within controllers.

g) Provide descriptions of any software functionality that enables intelligent charging and discharging of the ESS using interconnected DG, such as PV. For example, if the ESS can be charged only through the DG input, or if the ESS can be switched to be charged from the line input, provide those details in a sequence of operations. Provide details on grounding of the interconnected energy storage and/or DG system to meet utility effective grounding requirements.

h) Provide short circuit current capabilities and harmonic output from the Hybrid Project or stand-alone storage system

Market Participation:

a. Will the system operate in the ISO-NE markets? If yes, please specify.

b. Will the system be compensated under a utility tariff(s)? If yes, please specify.

The market participation information is non-binding; however, the operating characteristics as defined above will be used for technical study.