



FACILITY CONNECTION REQUIREMENTS
FOR
TRANSMISSION LINES AND END-USERS

PORTLAND GENERAL ELECTRIC
PORTLAND, OREGON
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**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

CONTENTS

<u>SECTION</u>	<u>PAGE</u>
1. Introduction	1
2. Scope	2
3. Connection Request and Study Requirements	2
A. Initial Request to PGE for Connection	3
B. Coordination with Affected Utilities	3
C. System Impact and Detailed Facilities Study	3
D. Study Results	3
E. Notification of Additions/Modification to other parties	4
4. General Requirements	5
A. Safety and Isolating Devices	5
B. Point of Connection Considerations	5
C. Transmission and Substation Facilities	7
D. Insulation Coordination	9
E. Substation Grounding	10
F. Inspection, Test, Calibration, and Maintenance	10
G. Station Service	13
H. Ancillary Services	13
5. Performance Requirements	14
A. Electrical Disturbances	14
B. Switchgear	14
C. Transformers, Shunt Reactors and Phase Shifters	15
D. Power Quality	15
E. Reliability and Availability	16
F. Power Factor	18
G. Isolating, Synchronizing and Blackstarts	18
H. Responsibilities During Emergency Conditions	18
6. Protection Requirements	19
A. Introduction	19
B. Protection Criteria	19
C. Protection System Selection and Coordination	25
D. Installation and Commissioning Test Requirements	26
7. System Operation and Data Requirements	27
A. Introduction	27
B. System Operation Requirements	27
C. Interchange Scheduling Requirements	29
D. Revenue or Interchange Metering	30
E. Calibration of Revenue and Interchange Metering Facilities	31
8. Telecommunication Requirements	34
A. Introduction	34
B. Telecommunications Availability	34
C. Voice Communications	35
D. Data Communications	35
E. Telecommunications for Control and Protection	36
F. Telecommunications during Emergency Conditions	36
9. Definitions	38
10. References	43
11. Interconnection Request Form (3 pages)	44

1. Introduction

Portland General Electric has prepared this document to identify technical requirements for connecting transmission lines and loads into the PGE transmission system (PGE System). The purpose of this document is to specify the minimum requirements necessary to assure the safe operation, integrity and reliability of the PGE System.

PGE evaluates new connection proposals on a case-by-case basis. Specific interconnection requirements are then provided back to the Requester. All requests for transmission service or new transmission facilities must be made pursuant to the terms of PGE's prevailing transmission tariff. PGE also calculates transfer capability in accordance with its prevailing transmission tariff.

Contractual matters, such as costs, ownership, scheduling, and billing are not the focus of this document. However, in general, the Requester is expected to assume the cost of all upgrades or new facilities necessary to satisfy the technical requirements and accommodate the Request.

To develop a properly designed connection, the electric power systems must be studied, without regard to ownership. The Requester usually assumes the cost of any System Impact Study and Facilities Study. The studies will consider issues such as short-circuit duties, transient voltages, reactive power requirements, stability requirements, harmonics, safety, operations, maintenance and Prudent Electric Utility Practices. Upon completion of the studies and after execution of a connection agreement, PGE will provide appropriate notification of new or modified facilities to WECC and others. This may include, but is not limited to, providing a project summary at a PGE meeting or inclusion of the project in the WECC Significant Additions report.

This document is not intended as a design specification or an instruction manual and the information presented is subject to change. Technical requirements stated herein are generally consistent with North American Electric Reliability Council (NERC), Western Electric Coordinating Council (WECC) and Northwest Power Pool (NWPP) principles and practices. This document is also intended to be consistent with the Federal Energy Regulatory Commission (FERC) regulations governing separation of transmission and generation functions. At the time of the request for a connection, the standards in place at that time will govern. The information presented is subject to change.

PGE wishes to thank the many organizations which provided input and to acknowledge The Bonneville Power Administration for certain selected material used in this document.

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2. Scope

The technical requirements contained herein generally apply to all new or modified line or load connections regardless of type or size. The location of the facility, type of connection, and impacts on the PGE System or another utility's system determine the specific requirements. The connection must not degrade the safe operation, integrity and reliability of the PGE System or the systems of others. The requirements in this document are intended to protect PGE facilities, but cannot be relied upon to protect the Requester's facilities. Although a physical connection may not exist, this document also addresses technical requirements for dynamic signals.

2-A Applicable Codes, Standards, Criteria and Regulations

To the extent that the codes, standards, criteria and regulations are applicable, the facilities shall be in compliance with those listed in Section 10 of this document.

2-B Safety, Protection, and Reliability

PGE, in cooperation with affected parties, makes the final determination as to whether the PGE System is properly protected before an interconnection is closed. The Requester is responsible for correcting such problems before facilities are energized or interconnected operation begins. However, PGE may determine equivalent measures to maintain the safe operation and reliability of the PGE System. In situations where there is direct connection with another utility's system, the requirements of that utility also apply.

2-C Requester Responsibilities

The Requester is responsible for the planning, design, construction, reliability, protection, and safe operation and maintenance of the Requester's facilities unless otherwise identified in the construction, operation and/or maintenance agreements.

2-D Special Disturbance Studies

PGE uses series and shunt capacitors, high-speed reclosing, single-pole switching and high-speed reactive switching at various locations. These devices and operating modes, as well as other disturbances and imbalances, may cause stress on connected facilities. The Requester is responsible for any studies necessary to evaluate possible stresses on the proposed facilities and for all corrective actions.

2-E Study Estimates

PGE develops cost estimates on a case-by-case basis when appropriate. PGE may provide estimates for the required facilities that are identified by the Facilities Study and shown on the approved Project Requirements Diagram.

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3. Connection Request and Study Requirements

Generally, all requests for transmission service must be made pursuant to the terms of PGE's prevailing transmission tariff. If a connection is requested without an accompanying transmission service request, the connection and its operation will comply with regional practices. . If at any time, the requester designates the connection as a transmission service request, they should submit a Transmission Service Request Form. (See PGE's OATT – Section II: Point-To-Point Service and Section III: Network Integration Transmission Service, for applicable forms and instructions).PGE should be contacted as early in the planning process as possible for any potential transmission line or load connections to the PGE System. Changes within certain areas of PGE System may be costly due to extensive reinforcements. That is, PGE may have to add or modify its transmission system substantially before allowing a new transmission line or load to begin connected operation. A study must be made to determine the required facilities and modifications to accommodate the new connection. This study may also address the transmission system capability, transient stability, voltage stability, losses, voltage regulation, power quality (harmonics, voltage flicker), electromagnetic transients, machine dynamics, ferroresonance, metering requirements, protective relaying, substation grounding, and fault duties.

3-A. Initial Request to PGE for Connection

For any connection not accompanied by a Transmission Service Request, the Requester should provide PGE with sufficient information to determine if a detailed System Impact Study and a Facilities Study are required, by submitting a Transmission/End-User Connection Request form (a copy of this form is included in Section 11 of this document) as early as possible with all available information. PGE then performs a preliminary connection study, basing its analysis on the information provided. All Transmission Service Requests should consult PGE's OATT for process and procedures.

3-B. Coordination with affected utilities

In conducting the preliminary connection study, PGE will determine if any surrounding systems are affected (affected systems). PGE will then coordinate and cooperate in the conduct of any Studies performed by any affected system. PGE may also choose to coordinate construction on its own system with the construction required by others, if reasonable to do so., Once they are identified, PGE will invite such affected system operators to all meetings held with the Requestor. The Requestor will be expected to cooperate with PGE in all matters related to the conduct of studies and the determination of modifications.

3-C. System Impact and Detailed Facilities Study

If a System Impact Study and a Facilities Study are required, PGE will notify the Requester and forward a study agreement to cover the cost of the study. The Requester will then be expected to complete the form. This form provides PGE with specific information required for the studies.

The System Impact and Facilities Studies can require considerable time and effort, depending on the type of connection and its potential system impacts. Because of this, PGE and the Requester must enter into an agreement prior to performing each of the studies. At the conclusion of each study, PGE will issue a report which outlines the study results and may also include the following:

1. Study assumptions;
2. Alternatives considered;
3. Jointly coordinated recommendations, if any.

3-D. Study Results

The System Impact Study and Facilities Study results may include the following:

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1. A preliminary Project Requirements Diagram;
2. Any modifications and/or additions needed to PGE's Transmission System to accommodate the connection;
3. The major connection equipment that the Requester would provide;
4. The requirements for voltage regulation, harmonics, and power factor control;
5. Revenue metering and interchange telemetering requirements;
6. Protective relaying, grounding, remedial action and control requirements;
7. Telecommunication requirements;
8. Operational control of facilities and maintenance requirements;
9. Approximate schedule and lead times for PGE to perform its design, material procurement, construction and energization;
10. An estimate of costs for additions and modifications to be performed by PGE; and
11. The alternate locations where the Project facility(s) may be connected to PGE's System.

3-E. Notification of Additions/Modification to other parties

After execution of an appropriate agreement, PGE will report the addition and/or modification of facilities to the Western Electric Coordinating Council (WECC) as part of its Annual Progress Report and Significant Additions filing for non-WECC members. Requestors who are WECC members will submit additions not considered part of the PGE system. Furthermore, those additions and/or modifications will be reported to the regional security coordinator once they are placed in service.

4. General Requirements

4-A. Safety and Isolating Devices

At the Connection Point to the PGE System, an isolating device, which is typically a disconnect switch, shall be provided that physically and visibly isolates the PGE System from the connected facilities. Safety and operating procedures for the isolating device shall be in compliance with the PGE and Requester's safety manuals. All switchgear that could energize equipment shall be visibly identified, so that all maintenance crews can be made aware of the potential hazards. The isolating device may be placed in a location other than the Connection Point, by agreement of PGE and affected parties. In any case the device:

- Must simultaneously open all phases (gang operated) to the connected facilities;
- Must be a manually operated disconnect switch for connections at 230 kV and below;
- Must be accessible by PGE and may be under ultimate PGE Dispatcher jurisdiction;
- Must be lockable in the open position by PGE;
- Would not be operated without advance notice to either party, unless an emergency condition requires that the device be opened to isolate the connected facilities; and
- Must be suitable for safe operation under the conditions of use.
- Must have ratings equal to or greater than the line or facility being connected to the PGE system.

PGE personnel may lock the device in the open position and install safety grounds:

- If it is necessary for the protection of maintenance personnel when working on deenergized circuits;
- If the connected facilities or PGE equipment presents a hazardous condition;
- If the connected facilities jeopardize the operation of the PGE System.

If the isolating device is located in a PGE substation or switchyard, any persons accessing the device for inspection, operation or maintenance must be fully trained and qualified as defined in the applicable OSHA regulations. These persons must also receive training by PGE, at the Requester's expense, on PGE's operating and safety practices. All clearances will be under the jurisdiction of the PGE dispatcher. All operations and clearances will follow the procedures in the PGE Electrical System Switching and Tagging Handbook.

If the isolating switch is located at a substation or switchyard owned by the customer or interconnecting utility, an operating one-line must be provided to PGE. Revisions to this one line shall be issued to PGE when changes are made to the station.

For customer substations, PGE shall have operational access to the circuit breaker, circuit switcher or switch to drop the load or transformer following agreement between the PGE Dispatcher and the customer.

4-B. Point of Connection Considerations

1. General Constraints

Connected facilities shall not restrain PGE from taking a transmission line or line section or other equipment out of service for operating or maintenance purposes. The line and all components must be designed and installed to accommodate PGE's right to maintain its equipment and facilities. If necessary to ensure maintainability, PGE will install pole mounted line sectionalizing disconnect switches at the customer's expense.

2. General Configurations

Connection of new facilities into the transmission system usually falls into one of four categories:

- a. Connection into an existing 57-kV to 500-kV bulk power substation, with (depending on the bus configuration) the existing transmission and new connecting lines each terminated into bays containing one or more breakers;
- b. Connection on the low-voltage side (typically 13-kV) of a new or existing power transformer in a PGE owned substation. This connection, which is discussed below, may create a multi-terminal line if the load side of the transformer includes a generation source or is non-radial on the low voltage side;

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- c. Connection at 57-kV to 500-kV by directly tapping an existing transmission line; or
- d. Connection at 57-kV to 500-kV by looping an existing transmission line into a new customer or PGE owned substation. This connection may result in a new, non-PGE owned substation within an existing transmission path.

PGE must maintain full operational control of the transmission path. This may include, but not be limited to, SCADA control and monitoring of circuit breakers, disconnects and other equipment in the new substation. Additionally, PGE will retain contractual path rights. Any new equipment shall not degrade the operational capability of the line.

A multi-terminal line is created when the new connection, such as b or c above, becomes an additional source of real power and fault current beyond the existing sources at the line terminals. A line with three terminals affects PGE's ability to protect, operate, dispatch, and maintain the transmission line. The increased complexity of the control and protection schemes affects system stability and reliability. The additional terminal may also decrease the overall performance and availability of the existing line. PGE determines the feasibility of multi-terminal line connections on a case-by-case basis. If an agreement is reached to establish a multi-terminal line, PGE may require new or additional relays or pilot relaying in PGE substations in order to maintain operability and reliability of the new configuration. All additional relays or relaying schemes required will be installed at the customer's expense.

These four categories can include the situation where another utility owns the transmission line or equipment that directly connects to the PGE System.

3. Special Configurations

The following configuration may substantially affect the costs of a particular connection plan, sometimes making an alternate Connection Point more desirable.

a. Connection to Main Grid Transmission Lines and Substations

Main Grid transmission lines include all 500 kV, and some lower voltage lines, as defined by PGE's Reliability Criteria. These circuits form the backbone of the PGE transmission system and provide the primary means of serving large geographical areas. The use of three-terminal lines on the Main Grid often adversely affects system stability and reliability, as well as critical operation and maintenance of these lines. Therefore PGE discourages proposals to create three-terminal lines on the Main Grid. Typically a substation, with additional breakers at the Connection Point, will have to be developed. The cost of this step may make connection to non-Main Grid lines more appropriate for most lines and loads.

4. Other Considerations

a. Existing Equipment

Existing electrical equipment, such as transformers, power circuit breakers, disconnect switches, arresters, and line conductors were purchased based on the duties expected in response to system additions identified in long-range plans. However, the connection of a new line or load may cause existing equipment to be underrated, requiring replacement.

b. System Stability and Reliability

The PGE System has been developed with careful consideration for system stability and reliability during disturbances. The type of connection, size of the load, breaker configurations, load characteristics, and the ability to set protective relays will affect where and how the Connection Point is made. The Requester may also be required to participate in special protection schemes, called remedial action schemes (RAS) such as generator dropping, load shedding, or load tripping. The portion of the transmission path capacity that the Requester uses determines the pro rata share of RAS. If RAS participation is required, the Requester and PGE will jointly plan and coordinate the RAS implementation.

c. Control and Protection

PGE coordinates its protective relays and control schemes to provide for personnel safety and equipment protection and to minimize disruption of services during disturbances. New Connection Points usually require the addition or modification of protective relays and/or control schemes. The new protection must be compatible with existing protective relay schemes. Sometimes the addition of voltage transformers, current transformers, or pilot scheme (transfer trip) also is necessary. PGE uses single-pole protective relaying on

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most 500 kV lines and pilot tripping on most 230 kV lines. Conventional directional zone protection is usually used on 57 to 230 kV lines. Distribution type protection is generally used for circuits below 57 kV. At the time of the connection request, PGE will supply the Requester with an approved list of protective relay systems suitable for the interconnection. Should the Requester select a relay system not on our approved list, PGE reserves the right to perform a full set of acceptance tests, at the Requester's expense, prior to granting permission to use the selected protection scheme.

d. Dispatching and Maintenance

PGE operates and maintains its system to provide reliable customer service while meeting the seasonal and daily peak loads even during equipment outages and disturbances. New line and load connections must not restrict timely outage coordination, automatic switching or equipment maintenance scheduling. Preserving reliable service to all PGE customers is essential and may require additional switchgear, equipment redundancy, or bypass capabilities at the Connection Point for acceptable operation of the system.

e. Atmospheric and Seismic

The effects of wind storms, floods, lightning, elevation, temperature extremes, icing, contamination and earthquakes must be considered in the design and operation of the connected facilities. The Requester is responsible for determining that the appropriate standards, codes, criteria, recommended practices, guides and prudent utility practices are met for equipment that they are installing.

4-C. Transmission and Substation Facilities

Some new connections to the PGE System require that one or more PGE lines (a transmission path) be looped through the Requester's facilities, or sectionalized with the addition of switches. The design and ratings of these facilities and/or switches shall not restrict the capability of the line(s) and PGE's contractual transmission path rights.

1. **Transmission line designs** shall meet the requirements of PGE's Standards, Rating Criteria, and Preferred Practices which, among other things, indicate that:
 - a. The requirements of the NESC C2 and OSHA shall be met.
 - b. The line shall be designed and sagged to meet or exceed clearance requirements of the NESC C2 while operating at 100°C (ACSR) or 93°C (AAC) operating temperature.
 - c. All new transmission lines connecting to a PGE substation may be required to have one or more overhead ground wires (OHGW) to provide substation shielding.
 - d. All lines 230 kV and higher connecting to a PGE substation may be required to have surge arresters for substation entrance protection. PGE staff will recommend the appropriate level of entrance protection for installations in PGE substations.
 - e. Access to all structures shall be provided and maintained.
 - f. Underbuilds to existing PGE transmission line facilities will generally not be allowed. If an underbuild is requested, a special 'joint-use pole agreement' will have to be negotiated.
2. **Customer-built substations** that tap or interrupt an existing PGE transmission path or customer-built facilities in a PGE substation must meet PGE requirements and the requirements of all applicable codes and standards including but not limited to the following:
 - a. The facility must be designed to applicable requirements of the NESC C2, NEC, ANSI and IEEE Standards.
 - b. The design must consider environmental and oil containment regulations for an installation in a PGE substation.
 - c. Grounding must be in accordance with IEEE Guide 80.
 - d. Two sources of station service will be required to maintain battery charging for any transmission switching other than manual switching.

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- e. Electrical equipment in the substation must be sized to carry the full current rating of the interrupted transmission path. This includes the bus, circuit breakers, disconnect switches, current transformers and all other ancillary equipment which will serve as the continuation of the path during any switching configuration.
- f. Customer substations that anticipate ties to or an alternate source from the PGE distribution system must accommodate the phase shift between the PGE transmission system and the PGE distribution system. PGE uses delta – wye connected transformers in PGE distribution substations. See figure 4-1 below for phasing.
- g. Connections to an existing PGE line will be designed and installed by PGE.
- h. A full set of construction drawings shall be provided to PGE for review.
- i. A PGE lock shall be installed on the entrance gate to allow PGE operational access to the isolating switch.
- j. Transmission conductors into a customer substation will not be energized until the substation meets safety standards as described in the codes referenced above.

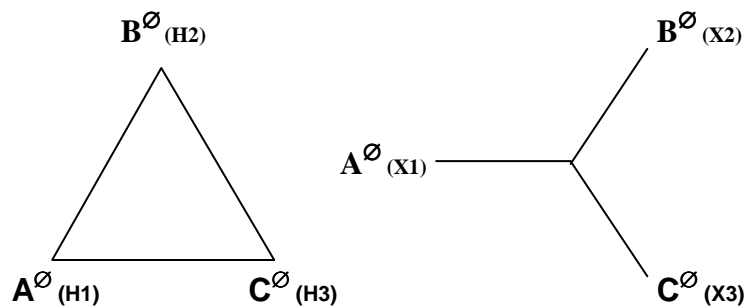


FIGURE 4-1

PGE Transformer Phase Connections

115 – 13 kV

57 – 13 kV

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4-D. Insulation Coordination

Power system equipment is designed to withstand voltage stresses associated with expected operation. Adding or connecting new facilities can change equipment duty, and may require that equipment be replaced or switchgear, telecommunications, shielding, grounding and/or surge protection added to control voltage stress to acceptable levels. Connection studies include the evaluation of the impact on equipment insulation coordination. PGE may identify additional requirements to maintain an acceptable level of PGE System availability, reliability, equipment insulation margins, and safety.

Voltage stresses, such as lightning or switching surges, and temporary overvoltages may affect equipment duty. Remedies depend on the equipment capability and the type and magnitude of the stress. In general, stations with equipment operated at 15 kV and above, as well as all transformers and reactors, shall be protected against lightning and switching surges. Typically this includes surge arresters on the high voltage side of the transformers and possible surge arresters on transmission line positions. The following requirements may be necessary to meet the intent of PGE's Reliability Criteria.

1. Lightning Surges

If the Requester proposes to tap a shielded transmission line, the tap line to the substation must also be shielded. For an unshielded transmission line, the tap line does not typically require shielding beyond that needed for substation entrance. However, special circumstances such as the length of the tap line may affect shielding requirements.

Lines at voltages of 230 kV and higher that terminate at PGE substations must meet additional shielding and/or surge protection requirements identified in Section 4-C. For certain customer service substations at 230 kV, PGE may require an arrester at the station entrance in lieu of line shielding, or a reduced shielded zone adjacent to the station. These variations depend on the tap line length, the presence of a power circuit breaker on the transmission side of the transformer, and the size of the transformer.

2. Switching Surges

At voltages below 500 kV, modifications to protect PGE System equipment from switching surges are not anticipated. However, the results of the System Impact and Facility Requirements Study identify the actual needs. At 500 kV and usually at 230 kV, PGE requires that arresters be added to new line terminations at PGE substations.

3. Temporary Overvoltages

Temporary overvoltages can last from seconds to minutes, and are not characterized as surges. These overvoltages are present during islanding, faults, loss of load, or long-line situations. All new and existing equipment must be capable of withstanding these duties.

a. Local Islanding

When the connection involves tapping a transmission line, a 'local island' may be created when the breakers at the ends of the transmission line open. This can leave generating resources and any other loads that also are tapped off this line isolated from the power system. Delayed fault clearing, overvoltages, ferroresonance, extended undervoltages, and degraded service to other PGE customers can result from this 'local island' condition. Therefore local islands involving PGE transmission facilities are not allowed to persist. Special relays to detect this condition and isolate the local generation from PGE facilities are described in Section 6-B2.

b. Neutral Shifts

When generation or a source of 'back-feed' is connected to the low-voltage side of a delta-grounded wye customer service transformer, remote end breaker operations initiated by the detection of faults on the high-voltage side can cause overvoltages that can affect personnel safety and damage equipment. This type of overvoltage is commonly described as a neutral shift and can increase the voltage on the unfaulted phases to as high as 1.73 per unit. At this voltage, the equipment insulation withstand-duration can be very short. Several alternative remedies are possible:

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- Provide an effectively grounded system on the high-voltage side of the transformer that is independent of other transmission system connections.
- Size the high-voltage-side equipment to withstand the amplitude and duration of the neutral shift.
- Rapidly separate the back-feed source from the step-up transformer by tripping a breaker, using either remote relay detection with pilot scheme (transfer trip) or local relay detection of overvoltage condition (see Section 6-B2).

Effectively grounded is defined as an $X_0/X_1 \leq 3$ and $R_0/X_1 \leq 1$. Methods available to obtain an effective ground on the high-voltage side of the transformer include the following:

- A transformer with the transmission voltage (PGE's) side connected in a grounded-wye configuration and low voltage (Connection Point) side in closed delta.
- A three-winding transformer with a closed-delta tertiary winding. Both the transmission and distribution side windings are connected in grounded wye.
- Installation of a grounding transformer on the transmission voltage (PGE) side.

Any of these result in an effectively grounded system with little risk of damage to surge arresters and other connected equipment.

4-E. Substation Grounding

Each substation must have a ground grid that is solidly connected to all metallic structures and other non-energized metallic equipment. This grid shall limit the ground potential gradients to such voltage and current levels that will not endanger the safety of people or damage equipment which are in, or immediately adjacent to, the station under normal and fault conditions. The ground grid size and type are in part based on local soil conditions and available electrical fault current magnitudes. In areas where ground grid voltage rises would not be within acceptable and safe limits (due for example to high soil resistivity or limited substation space), grounding rods and grounding wells can be used to reduce the ground grid resistance to acceptable levels.

If a new ground grid is close to another substation, the two ground grids may be isolated or connected. If the ground grids are to be isolated, there must be no metallic ground connections between the two substation ground grids. Cable shields, cable sheaths, station service ground sheaths, and overhead transmission shield wires can all inadvertently connect ground grids. A fiber optic cable is an excellent choice for telecommunications and control between two substations to maintain isolated ground grids. If the ground grids are to be interconnected, the interconnecting cables must have sufficient capacity to handle fault currents and control ground grid voltage rises. PGE must approve any connection to a PGE substation ground grid.

New interconnection of transmission lines and/or generation may substantially increase fault current levels at nearby substations. Modifications to the ground grids of existing substations may be necessary to keep grid voltage rises within safe levels. The connection study will determine if modifications are required and the estimated cost.

The ground grid should be designed to applicable ANSI and IEEE Standards relating to safety in substation grounding [Ref. 2.1, 2.2, 2.4, 2.5, 2.6, 2.7].

Voltage transformers and CCVT's will utilize shielded control wire for secondary circuits that is grounded at both ends. It is recommended that a ground conductor closely parallel the secondary conductors.

4-F. Inspection, Test, Calibration and Maintenance

All transmission elements (i.e. lines, line rights of way, circuit breakers, control and protection equipment, metering, and telecommunications) shall be inspected and maintained in conformance with regional standards, taking into consideration geographical differences. The utility may be requested to annually certify that it has documented, and implemented an adequate transmission maintenance and inspection plan. The Requester has full responsibility for the inspection, testing, calibration, and maintenance of its equipment, up to the location of change of ownership or Connection Point.

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1. Pre-energization Inspection and Testing

Before initial energization, the Requester shall develop an Inspection and Test Plan for pre-energization and energization testing. PGE may require additional tests; the costs of these tests are subject to negotiation. The Requester shall make available to PGE all drawings, specifications, and test records of the Connection Point equipment. Refer to Section 6-D for specific installation testing requirements for protection systems.

2. Transmission Maintenance and Inspection Plan

It is the intent of these maintenance requirements to provide flexibility in the approach to maintenance, but require the description of certain specific maintenance practices. The maintenance and inspection plan shall provide descriptions of the various maintenance activities, schedules and condition triggers for performing the maintenance, and samples of any checklists, forms, or reports used for maintenance activities. The Requester shall prepare a written description of, and update as necessary, its maintenance and inspection plan.

The maintenance and inspection plan may be performance-based, time-based, or both, as may be appropriate. The maintenance and inspection plan shall:

- Include the schedule interval (i.e., every two years) for any time-based maintenance activities and a description of conditions that will initiate any performance-based activities;
- Describe the maintenance methods for each substantial type of component and shall provide any checklists or forms that may be required for the activity;
- Provide criteria to be used to assess the condition of a transmission facility or component;
- Specify, for each type of equipment, the condition or performance assessment criteria and the appropriate response to each condition.

a. Transmission Line Maintenance

The maintenance and inspection plan shall, at a minimum, describe the maintenance practices for all applicable transmission line activities including

- Patrols and inspections, routine, detailed and emergency.
- Vegetation Management and right-of-way maintenance.

The maintenance and inspection plan shall describe the maintenance practices for various attributes of the transmission lines for all applicable facilities:

- Structures (e.g., wood pole, lattice steel, tubular steel, and concrete pole, etc.),
- Guys and anchors,
- Foundations,
- Insulators,
- Conductor and shield wire,
- Conductor and shield wire clearances,
- Hardware and fittings,
- Disconnects and pole-top switches,
- Fence grounds, and
- Encroachments, unauthorized attachments and joint use.

b. Station Maintenance

The maintenance and inspection plan shall describe the maintenance practices for all applicable station facilities:

- Switching devices (circuit breakers, circuit switchers and disconnects),
- Wound devices (power transformers, reactors, regulators and instrument transformers),
- Reactive devices (series and shunt capacitors, and static VAr system),
- Surge protective devices (arresters and rod gaps),
- Substation insulation (insulators and bushings),
- Gas insulated substation equipment,
- Metering,
- Battery systems,
- Relaying,
- Telecommunication facilities,
- Station auxiliary equipment, and
- Structures and foundations.

The maintenance and inspection plan shall also describe the maintenance practices for:

- Visual and environmental inspection (such as fences and grounds, vegetation, clearances, electrical tracking, abnormal heating, cracks, chips, noise, leaks, blown fuses, and bulging of equipment cases),
- Oil containment,
- Insulation mediums,
- Equipment contacts,
- Mechanical timing,
- Contamination control,
- Testing and calibration,
- Cooling systems,
- Measuring devices, and
- Lubrication and overhaul of moving parts.

c. Maintenance Record Keeping and Reporting

Maintenance records of all maintenance and inspection activities for at least five years shall be maintained. The records of maintenance and inspection activities shall be made available as required and requested to demonstrate compliance with the maintenance and inspection plan. The maintenance and inspection records shall, at a minimum:

- Identify the person(s) responsible for performing the work or inspection;
- Indicate the date(s) the work or inspection was performed;
- Identify the transmission facility; and
- Describe the inspection or maintenance that was performed.

The transmission owner shall maintain and make available on request, records for substantial maintenance or inspection as limited by the following list:

Transmission Line Maintenance:

- Patrol and inspection,
- Vegetation management and right-of-way maintenance,
- Structures (wood pole, lattice steel, tubular steel and concrete pole), and

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- Insulators (contamination control).

Station Maintenance:

- Switching devices (circuit breakers, circuit switchers and disconnects),
- Wound devices (power transformers, reactors, regulators and instrument transformers),
- Reactive devices (series and shunt capacitors, and static VAr system),
- Surge protective devices (arresters and rod gaps),
- Substation insulation (insulators and bushings),
- Gas insulated substation equipment,
- Relaying, and
- Telecommunications.

3. Calibration and Maintenance of Revenue and Interchange Metering

Most revenue and interchange metering will be calibrated at least every two years. Other calibration intervals may be negotiated. All interested parties or their representatives may witness the calibration tests. Calibration records shall be made available to PGE upon request.

4-G. Station Service

Power that is provided for local use at a substation to operate lighting, heat and auxiliary equipment is termed station service. Alternate station service is a backup source of power, used only in emergency situations or during maintenance when primary station service is not available.

Station service power is the responsibility of the Requester. The station service requirements of the new facilities, including voltage and reactive requirements, shall not impose operating restrictions on the PGE transmission system beyond those specified in applicable NERC, WECC, and NWPP reliability criteria.

Appropriate providers of station service and alternate station service are determined during the connection planning process, including Project Requirements Diagram development and review. Generally, the local utility will be the preference provider of primary station service unless it is unable to serve the load, or costs to connect to the local utility are prohibitive.

The Requester must provide metering for station service and alternate station service, as specified by the metering section of this document or work out other acceptable arrangements.

4-H. Ancillary Services

All loads and transmission facilities must be part of a control area. The control area provides critical ancillary services, including load regulation, load following, voltage control, scheduling, and dispatching, as defined by NERC, WECC, and NWPP reliability policies and criteria, or their successors. All new connections to the PGE System also require a transmission contract. The Requester must choose the control area in which the new facilities will be located and how all the necessary ancillary services will be provided. This should be done in the ancillary service exhibit of the transmission contract.

Of particular importance is the Requester's selection of the source for regulating and contingency reserves, if needed. PGE will then determine the telemetering, controls, and metering that will be required to integrate the load or facility into the chosen control area and to provide the necessary ancillary services. If the Requester chooses a self-provision or a third party provision of reserves, then special certification and deployment procedures must be incorporated into the PGE AGC system. The provision of the required ancillary services must meet all relevant NERC, WECC, and NWPP reliability policies and criteria, or their successors.

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5. Performance Requirements

The following performance requirements can be satisfied by various methods. It is the responsibility of the Requester to propose a preferred method for PGE concurrence.

5-A. Electrical Disturbances

The new facilities shall be designed, constructed, operated, and maintained in conformance with this document, applicable laws and regulations, and standards to minimize the impact of the following:

- Electric disturbances that produce abnormal power flows,
- Power system faults or equipment failures,
- Overvoltages during ground faults,
- Audible noise, radio, television, and telephone interference,
- Power system harmonics, and
- Other disturbances that might degrade the reliability of the interconnected system.

5-B. Switchgear

1. All Voltage Levels

Circuit breakers, disconnect switches, and all other current-carrying equipment connected to PGE's transmission facilities shall be capable of carrying normal and emergency load currents without damage. This equipment shall not become a limiting factor, or bottleneck, in the ability to transfer power on the PGE System.

All circuit breakers and other fault-interrupting devices shall be capable of safely interrupting fault currents for any fault that they may be required to interrupt. The circuit breaker shall have this capability without the use of intentional time delay in clearing, fault reduction schemes, etc. Application shall be in accordance with ANSI/IEEE C37 Standards. These requirements apply to the equipment at the connection point as well as other locations on the PGE System. Minimum fault-interrupting requirements are supplied by PGE, and are based on the greater of the fault duties at the time of the interconnection request or those projected in committed transmission plans.

The circuit breaker shall be capable of performing other duties as required for the specific application. These duties may include: capacitive current switching, load current switching, and out-of-step switching. The circuit breaker shall perform all required duties without creating transient overvoltages that could damage PGE equipment. Switchgear on the high side of a delta-grounded wye transformer that can interrupt faults or load must be capable of the increased recovery voltage duty involving interruptions while ungrounded. The connection of a transmission line or load can coincidentally include other generating resources. When this system configuration is connected to the low-voltage side of a delta-grounded wye transformer, the high-voltage side may become ungrounded when remote end breakers open, resulting in high phase-to-ground voltages. This phenomena is described in Section 4-D3b under 'neutral shifts.'

2. Circuit Breaker Operating Times

Table 5-1 specifies the operating times typically required of circuit breakers on the PGE System. These times apply to equipment at or near the Connection Point. System stability considerations may require faster opening times than those listed. Breaker close times are typically four to eight cycles. The automatic recloser times in Table 5-1 are the summation of the breaker close time plus intentionally added delay to allow for extinction of the fault arc (de-ionization), and the protective relay requirements. Circuit breaker interrupting time must coordinate with other circuit breakers and protective devices.

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Table 5-1 Circuit Breaker Operating Times

Voltage Class (kV L-L rms)	Rated Interrupting Time (Cycles)	Automatic Reclose Time (Cycles)
500 kV	2	20 - 90
230 kV	≤ 3	35 - 60
115 kV	3	35 - 120
57 kV	≤ 5	*
Below 57 kV	≤ 8	*

* - Varies significantly by line.

3. Other Fault-Interrupting Device Operating Times

Depending on the application, the use of other fault-interrupting devices such as circuit switchers may be allowed. Fuses may be adequate for protecting the high voltage side of a high voltage delta low voltage grounded wye transformer. Trip times of these devices are generally slower, and current-interrupting capabilities are often lower, than those of circuit breakers. These devices must have been tested for the duty in which they are to be applied and they must coordinate with other protective devices operating times. Use of transformer fuses may result in 'single phasing' of low side connected loads.

5-C. Transformers, Shunt Reactive and Phase Shifters

Transformer tap settings (including those available for under load and no load tap changers), reactive control setpoints, and phase shift angles must be coordinated with PGE to optimize both reactive flows and voltage profiles. Automatic controls may be necessary to maintain these profiles on the interconnected system. Timed changes should be coordinated with time schedules established by the NWPP.

5-D. Power Quality Requirements

1. Voltage Fluctuations and Flicker

Voltage fluctuations may be noticeable as visual lighting variations (flicker) and can damage or disrupt the operation of electronic equipment. IEEE Standard 519 [Ref. 2.5] provides definitions and limits on acceptable levels of voltage fluctuation. Loads or system connections to the PGE System shall comply with the limits set by IEEE 519. If it is determined that the new connection is the source of the fluctuations, the necessary equipment to control the fluctuations to the limits identified in IEEE 519 is the responsibility of the Requester.

2. Harmonics

Harmonics can cause telecommunication interference, increase thermal heating in transformers, disable solid state equipment and create resonant overvoltages. In order to protect equipment from damage, harmonics must be managed and mitigated. The new connection shall not cause voltage and current harmonics on the PGE System that exceed the limits specified in IEEE Standard 519. Harmonic distortion is defined as the ratio of the root mean square (rms) value of the harmonic to the rms value of the fundamental voltage or current. Single frequency and total harmonic distortion measurements may be conducted at the Connection Point, or other locations on the PGE System to determine whether the new connection is the source of excessive harmonics. If it is determined that the new connection is the source of the harmonic voltage and currents the necessary equipment to control the harmonic voltage and currents to the limits identified in IEEE 519 is the responsibility of the Requester.

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3. System Frequency During Disturbances

Power system disturbances initiated by system events such as faults and forced equipment outages, expose the system to oscillations in voltage and frequency. It is important that lines remain in service for dynamic (transient) oscillations that are stable and damped.

To avoid large-scale blackouts that can result from the excessive generation loss, major transmission loss, or load loss during a disturbance, underfrequency load shedding has been implemented in the Pacific Northwest. When system frequency declines, loads are automatically interrupted in discrete steps, with most of the interruptions between 59.3 and 58.6 Hz. Load shedding attempts to stabilize the system by balancing the generation and load. It is important that lines remain connected to the system during frequency declines, both to limit the amount of load shedding required and to help the system avoid a complete collapse.

4. Phase Unbalance

Unbalanced phase voltages and currents can affect protective relay coordination and cause high neutral currents and thermal overloading of transformers. To protect PGE and customer equipment, the contribution from the new facilities at the Connection Point shall not cause a voltage unbalance greater than 1% or a current unbalance greater than 5%. Phase unbalance is the percent deviation of one phase from the average of all three phases.

System problems such as a blown transformer fuse or open conductor on a transmission system can result in extended periods of phase unbalance. It is the Requester's responsibility to protect any of their connected equipment from damage that could result from such an unbalanced condition.

5. Voltage Schedules

Voltage schedules are necessary to maintain voltage profiles across the transmission system to insure that reactive flows are kept low and that optimum use of reactive control facilities can be maintained. To this end, a voltage schedule will be mutually developed between PGE and the Requester. PGE maintains voltages according to the ANSI Standard C84.1. This allows for variances of $\pm 5\%$ off nominal for all voltage levels.

6. Voltages During Disturbances

To avoid voltage collapse in certain areas of the Pacific Northwest, undervoltage load shedding has also been implemented. Most of the load interruptions will occur automatically near 0.9 per unit voltage after delays ranging from 3.5 to 8.0 seconds. Depending on the type and location of any new load, the Requester may be required to participate in this scheme.

5-E. Reliability and Availability

1. Maintaining service.

To minimize risk of overloads, instability, or voltage collapse, reliable operation of the interconnected power system requires the following: reactive sources, control of real and reactive generation, adequate real and reactive reserves, and maintenance of transmission system voltages.

2. Transmission lines.

Key transmission lines and other facilities should be kept in service when possible. Shutdown duration for maintenance activities on key transmission lines shall be kept to a minimum. The Requester shall plan and coordinate shutdowns with the PGE Dispatcher for planned maintenance activities in the event PGE maintenance activities could be impacted. Transmission lines may be removed from service for voltage control only after powerflow studies, in accordance with WECC requirements, indicate that system reliability will not be degraded below acceptable levels. The entity responsible for operating such transmission line(s) shall promptly notify other affected Control Areas, per the WECC *Procedure for Coordination of Scheduled Outages and Notification of Forced Outages*, or other applicable outages, when removing such facilities from and returning them back to service.

3. Switchable devices.

Devices frequently switched to regulate transmission voltage and reactive flow shall be switchable without de-energizing other facilities. Switches designed for sectionalizing, loop switching, or line dropping shall be capable of performing their duty under heavy load and maximum operating voltage conditions.

4. Frequency and Duration of Outages.

Planned outages of significant system equipment shall be coordinated with all affected parties to minimize their impact on the remaining system. Automatic and forced outages should be responded to promptly, mitigating any impacts on the remaining system, and in a manner that treats all customer interruptions with the same priority.

The design of the integrated system should strive to achieve the PGE automatic outage frequency and duration objectives. The exact value that a connection must be designed to is dependent upon the type and location of the connection and the required reliability of the adjacent transmission system.

5. Key Reliability and Availability Considerations

- a. The new connection shall meet the NWPP and WECC Minimum Reliability Standards for Planning and Operation.
- b. Tools and spare equipment must be readily available to accomplish operations and maintenance tasks.
- c. Bypass equipment must be fully rated to allow continued operation and not create a bottleneck. Alternate feeds, when provided, shall have sufficient rating to not restrict operation of the PGE System.
- d. Shielding and EMI protection shall be provided to insure proper equipment functioning during disturbances such as faults and transients.
- e. Standardized design, planning and operating practices and procedures should be used so the new connection may be readily incorporated into the existing transmission network.
- f. For reliable operation, the telecommunications, control and protection equipment must be redundant to the extent described in Sections 6 and 8.
- g. The equipment for the new connection shall have sufficient capabilities for both the initial operation and for long-range plans.
- h. Operations and maintenance personnel must be properly trained for both normal and emergency conditions.

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5-F. Power Factor Requirements

PGE and the Requester shall jointly plan and operate their systems, including reactive devices, so as not to place an undue burden on either Party to supply or absorb reactive power.

For each point of interconnection that is radial into PGE's transmission system, unless mutually agreed otherwise, the Requester shall maintain a 5-minute average power factor leading or lagging of 97 percent or higher.

- Each system is supposed to provide for their own reactive power requirements, both leading and lagging. Reactive power control including reserves is required to maintain adequate voltage levels to prevent voltage instabilities and insure transient stability.
- PGE encourages customers to maintain their own power factor without relying on the transmission system, especially under peak load conditions. Controlling reactive flow can enhance the transfer capability of the affected line and may also reduce system losses. Reactive flows at interconnection points should be kept at unity power factor.
- PGE will charge the Requester a reactive demand charge for all reactive power determined to be delivered or absorbed in excess of the stated limits. The demand charge will be as established in PGE's Open Access Transmission Tariff. If PGE is not able to supply or absorb this excess reactive power and additional equipment or construction of facilities is required or is the most economic method to supply or absorb the reactive power, PGE shall notify the Requester. If the Requester fails to take corrective action as requested by PGE, PGE may perform such corrective action. Any costs incurred by PGE in performing the corrective action shall be charged to and paid by the Requester.

5-G. Isolating, Synchronizing and Blackstarts

1. Isolation

At the Connection Point, the Requester shall not energize a de-energized PGE line unless the PGE Dispatcher specifically approves the energization. Where the connection is to a radial load the circuit may be interrupted and reclosed by PGE. In cases where the connection breaks an existing path, an autoisolation scheme may be required to sectionalize the connection to PGE System. If the connected facilities are networked or looped back to the PGE System or where generation resources are present, a switching device must open to eliminate fault contributions or neutral shifts. Once open, the device must not reclose until approved by the PGE dispatcher or as specified in the connection agreement.

2. Synchronization

The Requester's system or portion of system with energized generators must synchronize its equipment to the PGE System. The exception to this is under large-scale islanding conditions, where the PGE System will re-synchronize to neighboring systems over major inertias. Automatic synchronization shall be supervised by a synchronizing check relay, IEEE device 25.

3. Blackstarts

Loads that are scheduled and available for blackstarts are selected to avoid the trip-out of generation units by exceeding frequency and voltage setpoints. This is accomplished by selecting voltage variable loads, avoiding motor start-up loads and imposing block size limits (50 MW). During blackstart restoration, the tapped connection must be able to be opened to avoid interference with PGE restoration procedures on the PGE transmission path.

5-H. Responsibilities During Emergency Conditions

Each Control Area operator has the ultimate responsibility to maintain the frequency within its control area boundaries. All emergency operation involving the PGE transmission system must be coordinated with the PGE Dispatcher. Each party, as appropriate, must participate in any local or regional remedial action schemes. All loads tripped by underfrequency or undervoltage action must not be restored without the Control Area operator's permission. All energy transfer reductions need to be coordinated with the appropriate Control Area operator, and need to be made promptly. All parties have the responsibility for clear communications and to report promptly any suspected problems affecting others.

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6. Protection Requirements

6-A. Introduction

The protection requirements identified in this document are intended to achieve the following objectives:

- Minimize property damage to the general public, PGE, and PGE's customers.
- Minimize adverse operating conditions affecting PGE's System and customers.
- Permit the Requester to operate their system in a safe and efficient manner with minimum impact to the PGE System and PGE's customers.
- Comply with NERC, WECC and NWPP protection criteria in existence at the time of the connection request.

To achieve these objectives, certain protective equipment (relays, circuit breakers, etc.) must be installed. These devices ensure that faults or other abnormalities initiate prompt and appropriate disconnection from the PGE System. Protective equipment requirements depend on the plan of service. Significant issues that could affect these requirements include:

- The location and configuration of the proposed connection.
- The level of existing service and protection to adjacent facilities (including those of other PGE customers and potentially those of other utilities).
- The coincidental connection of a new generation resource which was not previously connected to the PGE System. In this case, the Requester will also have to follow the requirements for interconnection of generation resources [Ref. 1.5].

PGE works with the Requester to achieve an installation that meets the Requester's and PGE's requirements. PGE cannot assume any responsibility for protection of the Requester's system. Requesters are solely responsible for protecting their system and equipment in such a manner that faults, imbalances, or other disturbances on the PGE System do not cause damage to their facilities or result in problems with their customers.

6-B. Protection Criteria

The protection system must be designed such that the Requester's equipment or system is automatically isolated for the following situations:

- Multi-phase or ground faults within the Requester's or connected utilities' system,
- Abnormal operating conditions such as equipment failures (e.g. single-phasing), and
- System disturbances requiring isolation (e.g. load shedding).

1. General Protection Practices

The following summarizes the general protection practices as required by NERC and the WECC and specific practices and applications as applied to PGE System transmission lines and interconnections. The protection schemes necessary to integrate the new connection must be consistent with these practices and the equipment used to implement them. Table 6-1 gives relay and breaker operating time versus voltage levels.

a. All Voltages

1. Relays, breakers, etc. are required at the Connection Point or a connecting substation to isolate PGE equipment from the Requester's system during faults.
2. At the Connection Point, the Requester is not allowed to energize a de-energized line in the PGE System without approval of the PGE Dispatcher.
3. Breaker reclose supervision (automatic and manual including SCADA) may be required at the connecting substation and/or electrically 'adjacent' stations; e.g., hot bus and dead line check, synchronization check, etc.
4. Dual batteries are NOT required but each set of relays must have its own separately protected DC source.
5. Relay settings shall not infringe upon PGE ability to operate at maximum transfer levels, even with system voltages as low as 0.8 per unit.
6. Redundant relays systems are required such that no single protection system component failure would disable the entire relay system.
7. Protection schemes shall be designed with sufficient number of test switches and isolating devices to provide ease of testing and maintenance without the necessity for lifting wires. Isolating switches shall be alarmed or operating and maintenance tagging procedures developed and followed to assure switches are not inadvertently left in an open position.
8. Directional relay systems are required on all non-radial connections.
9. PGE reserves the right to review and recommend changes to the protection system and settings for equipment at the Connection Point.
10. Where it is practical, physical and electrical separation should be maintained between redundant protection systems to reduce the possibility of both systems being disabled by a single event or condition.
11. The protection system security and dependability and their relative effects on the power system must be carefully weighed when selecting the protection system.
12. If required, automatic underfrequency load tripping total trip time, including relay operate time and breaker operate time shall not exceed 14 cycles.

b. All Voltages Above 100 kV

1. Breaker failure relays (BFR) as required. Total time for BFR scheme fault clearing must not exceed 14 cycles. System requirements may dictate faster BFR operating times. Breaker failure relays do not have to be redundant.
2. Redundant directional relay systems are required if a single point of failure could disable the entire relay system. Both relay systems shall contain an instantaneous tripping element capable of outputting a trip in 1.5 cycles or less for faults within 85% of the line. If ground distance elements are used, the relay must include ground overcurrent elements to provide tripping for high-resistance ground faults.
3. Redundant telecommunications schemes may be required if time-delayed fault clearing can result in stability, cascading or voltage problems. In some cases, an acceptable alternative to redundant transfer trip schemes may include the use of a directional comparison-blocking scheme.

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4. The relay systems shall provide backup protection for loss of the telecommunication channel(s).
5. The selected pilot schemes and telecommunication system must be compatible with existing PGE protection and telecommunications equipment.
6. The telecommunications and pilot scheme(s) channels required for protection systems should be either continuously monitored, or automatically or manually tested.

c. 500 kV

1. Two independent sets of directional line protection with separate pilot telecommunication for each relay set shall be installed at each line terminal to trip the line terminal breakers.
2. Total fault clearing time with a pilot scheme must not be more than four cycles, including relay and breaker time.
3. Line protection may be required to be compatible with existing or future series compensation.
4. Protection must be able to interface with PGE's single-pole protection schemes.
5. Automatic reclosing shall be no faster than 35 cycles and usually no slower than 60 cycles for standard three-pole or single-pole switching.
6. Automatic reclosing is not allowed for multiphase faults near PGE bulk power substations or voltage-sensitive customers.

d. 230 kV

1. A pilot telecommunication scheme is necessary if high-speed clearing is required for any fault location for stability purposes or if remote tripping for equipment protection is required. If a pilot telecommunications scheme is required for stability purposes, it must be redundant or designed to allow high-speed tripping by the protective relays upon failure of the pilot scheme.
2. Total fault clearing time with a pilot scheme must not be more than four cycles, including relay and breaker operating time, when connected to a Main Grid line. Slower times may be acceptable for some lines. Refer to Table 6-1.
3. Automatic reclosing for single line-to-ground faults shall be no faster than 35 cycles and no slower than 60 cycles.
4. Automatic reclosing is not allowed for multiphase faults near PGE bulk power substations or voltage-sensitive customers. It is also acceptable to block reclosing for time-delayed trips as well.

e. 115 kV

1. A pilot telecommunication scheme may be required if high-speed clearing is required for any fault location for stability purposes or if remote tripping for equipment protection is required. If a pilot telecommunications scheme is required for stability purposes, it must be redundant or designed to allow high-speed tripping by the protective relays upon failure of the pilot scheme.
2. Total fault-clearing times, with or without a pilot scheme, must be provided for PGE review and concurrence. Breaker operating times, relay makes, types and models, and relay settings must be identified specifically.
3. Automatic reclosing for single line-to-ground faults shall be no faster than 35 cycles.
4. Automatic reclosing is allowed for multiphase faults.

5. Multi-shot automatic reclosing may be required for automatic line sectionalizing schemes. The total number of automatic recloses should not exceed three.

f. Below 100 kV

1. Redundant or overlapping relays systems are required such that no single protection system component failure would disable the entire relay system and result in the failure to trip for a fault condition.
2. Total fault-clearing times, with or without a pilot scheme, must be provided for PGE review and concurrence. Breaker operating times, relay makes, types and models, and relay settings must be identified specifically.
3. Multi-shot automatic reclosing is allowed. The total number of automatic reclosures should not exceed three.

2. Protection Measures

Protection systems must be capable of performing their intended function during fault conditions. The magnitude of the fault depends on the fault type, system configuration, and fault location. It may be necessary to perform extensive model line tests of the protective relay system to provide assurance the selected relay system is capable of detecting faults for various system configurations. Power system swings, major system disturbances and islanding may require the application of special protective devices or schemes. The following discussion identifies the conditions under which relay schemes must operate.

a. Phase Fault Detection

Phase overcurrent (type 50/51) and neutral overcurrent (type 50/51-N) relays are provided to detect abnormally high currents. These non-directional relays are used to detect faults on the distribution class lines or serve as supervisory fault detectors for transmission relays. They may also serve to backup other protective relays. Line differential relays may be a necessary consideration for some connections when coordination with other relays is not possible.

Infeed detection to faults within the power system usually requires directional current-sensing relays to remove the contribution to the fault from the Connection Point. Zone-distance relays usually serve this need. The distance relay is a good choice for this application since it is generally immune to changes in the source impedance.

b. Ground Fault Detection

Ground fault detection has varying requirements. The availability of sufficient zero sequence current sources and the ground fault resistance both significantly affect the relay's ability to properly detect ground faults. The same types of relays used for phase fault detection are suitable for ground fault detection. If ground fault distance relays are used, backup ground time- overcurrent relays should also be applied to provide protection for the inevitable high-resistance ground fault.

c. Islanding

Islanding describes a condition where the power system splits into isolated load and generation groups, usually when breakers operate for fault clearing or system stability remedial action. Generally, the 'islanded groups' do not have a stable load to generation resource balance. However, it is possible that, under unique situations, generator controls can establish a new equilibrium in an islanded group.

While operating in an islanded condition or during a system disturbance, power swings may result which can affect the operation of protective relays, especially distance relays. Out-of-step blocking is commonly available for distance relays to prevent them from operating during a power swing. However, the application of such schemes must be coordinated with PGE to assure that the blocking of the distance elements will not result in inappropriate or undesirable formation of islands.

d. Load Shedding

The Requester shall provide undervoltage and underfrequency load shedding at the locations and in the amount and settings defined by PGE. The Requester will be required by PGE to show proof of compliance and/or to test undervoltage and underfrequency load shedding schemes as determined necessary to ensure proper operation.

The proposed connection may require special load-shedding schemes based upon PGE Control Area requirements. These may include underfrequency load shedding, undervoltage load shedding, or direct load tripping. The intent of load shedding is to balance the load to the available generation, reduce the possibility of voltage collapse, and to minimize the impact of a system disturbance. Tripping levels, restoration, and other details of load-shedding schemes will be determined by PGE, following NERC, WECC and NWPP criteria.

e. Generator Dropping

The proposed connection may also require additional logic to supply signals to existing special protection schemes including, but not limited to, line-loss detection and generator dropping. These schemes are also designed to maintain the balance between system loads and available generation during and following a system disturbance. If the new connection includes generation not previously part of the PGE Control Area, the generation may also require additional special trip schemes.

f. Other Special Protection and Control Schemes

The location of the Connection Point, amount of load transfer expected and various other system conditions may require other special protection schemes. The need for and type of schemes required will be determined as part of the system studies done following the request for a new connection. For example, RAS may be required for stability purposes or out-of-step tripping may be needed for controlled system grid separations. Special breaker tripping or closing schemes (e.g. staggered closing, point-on-wave closing) may be necessary to reduce switching transients. These special protection and control schemes may require stand alone relay systems or additional capabilities of particular substation equipment (e.g. independent-pole operation of circuit breakers).

g. Relay Performance and Transfer Trip Requirements

Relay systems are designed to isolate the transmission line and/or load facilities from the PGE System. However, the performance (clearing time speed) of these local relay systems and the associated isolating devices (breakers, etc.) will vary. The protection equipment of the new connection must at least maintain the performance level of the existing protection equipment at that location. This may require transfer trip (pilot telecommunications) to insure high-speed and secure fault clearing. Transfer trip is required when any of the following conditions apply to the new connection. Other types of pilot tripping such as directional comparison, phase comparison or current differential may also be acceptable if the scheme chosen can achieve the total clearing times required.

1. Transient or steady-state studies identify conditions where maintaining system stability requires immediate isolation of the Connection Point facilities from the power system.
2. Special operational control considerations require immediate isolation of the Connection Point.
3. Extended fault duration represents an additional safety hazard to personnel and can cause significant damage to power system equipment (e.g. lines, transformers).
4. Slow clearing or other undesirable operations (e.g., extended overvoltages, ferroresonance, etc.), which cannot be resolved by local conventional protection measures, will require the addition of pilot tripping using remote relay detection at other substation sites. This scenario is a distinct possibility should a PGE circuit that connects other customer loads become part of a ‘local island’ that includes a generator.
5. When remote-breaker tripping is required to clear faults in a transformer not terminated by a high-side breaker, high-speed transfer tripping will be necessary. The transfer trip may also be required to block automatic reclosing. Other unique configurations may impose the same requirement.
6. Relay operate times are adjusted to coordinate for faults based on the local configuration (e.g. three terminal lines), fault currents available, etc. Total clearing times must be less than those listed in Table 6-1. Otherwise, immediate isolation of the Connection Point is required. Refer to Section 8-E for telecommunication issues as they pertain to control and protection requirements.

Table 6-1 – Relay and Breaker Operating Times by System Voltage

Connection Voltage (kV L-L rms)	Total Clearing Time (Cycles)	Maximum Relay Operate Time (Cycles)	PCB Trip Time (Cycles)	Time Delayed Tripping Acceptable?
500	4	1	2	No*
230 Main Grid	4	1	2	No*
230	28	≤ 25	3	Yes
100 to 230	47	≤ 42	≤ 5	Yes
≤ 57	68	≤ 60	≤ 8	Yes

* - Transfer trip not an optional consideration

h. Synchronizing and Reclosing

If the connection is made to an existing line, automatic reclosing schemes at the remote line breakers may need to be modified. On transmission lines below 115 kV, automatic sectionalizing schemes may be installed to isolate a portion of the system that has a permanent fault. This may include multi-shot automatic reclosing at remote terminals. A new Connection Point should be compatible with such existing schemes. If the new connection results in the possibility of connecting a generation source to the PGE System, special considerations may be required.

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i. Protection System Performance Monitoring

Depending upon the type and location of the connection, monitoring equipment may be required. The monitoring equipment is intended to identify possible protection scheme problems and to provide power quality measurements. The monitoring equipment may provide information similar to that of an oscillograph or fault recorder. The availability of current and voltage measurements determines the number of channels for the device. Sequential event recorders and/or annunciators may also be required to record and time-tag operations of protection equipment. In some cases, it may be acceptable to utilize the recording and monitoring capabilities of a protective relay system to provide for system monitoring and event recording.

These recorders are connected to a GPS satellite receiver or other time source with equivalent accuracy. PGE will supply a list of quantities to be monitored and the appropriate terminology when connections are made at a PGE-owned substation. If monitoring or relay performance indicates inadequate protection of the PGE System, the owner of the connected facilities will be notified of additional protection requirements or changes.

PGE may request limited remote telecommunications access to relay systems at the Connection Point to query their operational history and fault data.

6-C. Protection System Selection and Coordination

1. Relays to be Installed for the Connection

At the time of the connection request, PGE will supply the Requester with an approved list of protective relay systems considered to be suitable for use at the Connection Point. The performance of protective relays applied at the connection that can directly affect the performance of the PGE System should follow the recommendations from the supplied list. Should the Requester select a relay system not on our approved list, PGE reserves the right to perform a full set of acceptance tests prior to granting permission to use the selected protection scheme. Alternatively, the relay vendor or a third party may be asked to perform thorough model line tests of the proposed relay system.

2. Protection System Coordination and Programming

The following are basic considerations that must be used in determining the settings of the protection systems. Depending upon the complexity and criticality of the system at the Connection Point, complete model line testing of the protection system, including the settings and programming, may have to be performed prior to installation to verify the protection system performance.

- Fault study models used for determining protection settings should take into account significant mutual and zero sequence impedances. Up-to-date fault study system models shall be used.
- Protection system applications and settings should not normally limit transmission use.
- Application of zone 3 relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible.
- Protection systems should avoid tripping for stable swings on the interconnected transmission systems.
- Protection system applications and settings should be reviewed whenever significant changes in generating sources, transmission facilities, or operating conditions are anticipated.
- All protection system trip misoperations shall be analyzed for cause and corrective action taken.

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6-D. Installation and Commissioning Test Requirements for Protection Systems

Thorough commissioning or installation testing of the protection system(s) is an important step for the installation of a new terminal or when changes to the protection system are made. The protection system includes the protective relays, the circuit breakers, instrument transformer inputs, and all other inputs and outputs associated with the protection scheme. The actual protection equipment used also will determine the type and extent of commissioning tests required. The following tests are the minimum required.

- 1. Verifying all protective system inputs.**
 - Current and voltage transformers: check the ratio, polarity, accuracy class, and single-point grounding.
 - Verify all other inputs to the protection system including battery supplies, circuit breaker auxiliary switches, pilot channel inputs, etc.
- 2. Verify protection system settings.**
 - Check protection system settings and programming.
 - Perform acceptance testing of protection system if not done previously.
 - Perform calibration tests of the protection system using actual settings.
- 3. Protection system drawings and wiring**
 - Verify switchboard panel and equipment wiring is intact and matches drawings.
 - Verify drawings are correct.
- 4. Verify proper relay system operation and directionality.**
- 5. Verify all protective system outputs.**
 - Trip outputs: trip intended trip coil(s) and open breaker
 - Close outputs: energize close coils and close the breaker(s)
 - Assure relay outputs to pilot channel are functional.
 - Assure all other outputs such as breaker failure initiate, special protection scheme signals, alarms, event recorder points, etc. are functional.
- 6. Perform trip or other operational tests.**
 - Assure correct operation of the overall protection systems.
 - Test automatic reclosing.
- 7. Pilot schemes**
 - Measure channel delays.
 - Check for noise immunity.
 - Check for proper settings, programming, etc.
 - Check transmit and receive levels.
 - If automatic channel switching or routing is utilized, check for proper relay operation for alternate routing.

Many utilities now use coordinated end-to-end tests to verify the overall operation of the protection system and the pilot channel as part of their commissioning tests. This is an acceptable method of operational testing. Modifications to a protection system also require similar testing to ensure correct system operation. The extent of testing and types of tests required depend upon the modifications made.

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7. System Operation and Scheduling Data Requirements

7-A. Introduction

All transmission arrangements for power schedules within, across, into or out of the PGE Control Area require metering and telemetering. Transmission arrangements with loads or new transmission facilities may include wheeling, voltage control, and Automatic Generation Control (AGC). The technical plan of service for interconnecting a load or new transmission facility, as shown on the Project Requirements Diagram, will include the metering and telemetering equipment consistent with the transmission contract provisions. Such metering and telemetering equipment may be owned, operated, and maintained by PGE or by other parties approved by PGE.

Revenue metering, system dispatching, operation, control, transmission scheduling and power scheduling each have slightly different needs and requirements concerning metering, telemetering, data acquisition, and control. Specific requirements also vary depending upon whether the new connection is directly connected to the PGE System or electronically connected via telemetering that places the connection within or outside the PGE Control Area.

7-B. System Operation Requirements

1. Telemetering Requirements

PGE's System Control Center (SCC) requires telemetering data for the integration of new interconnections at adjacent Control Area boundaries. This typically consists of the continuous telemetering of kW quantities and hourly transmission of the previous hour's kWh from the Connection Point to the PGE transmission dispatching and control center.

Section 8-D discusses telecommunications requirements for telemetering and AGC. Table 7-1 summarizes telemetering requirements and Table 7-2 identifies requirements based on connection location. The following includes generic requirements based on connection size:

- a. Telemetering is required for all normally closed interconnections at a PGE Control Area boundary. For this case, telemetering of real power and energy (kW, kWh) is required. There may be a need for reactive power (kVAr, kVArh) information for power factor billing purposes also. High capacity interconnections may require redundant metering and telemetering.
- b. For normally open or emergency tie connections, PGE determines telemetering needs on a case-by-case basis. Note that FERC requires telemetering for these connections.
- c. For loads connected internally to the PGE Control Area, AGC telemetering is not normally required. For interruptible loads, PGE determines telemetering needs on a case-by-case basis. Connecting eccentric (non-conforming) loads may require an interface to the PGE AGC system. Existing practices throughout North America usually require a warning signal of pre-loading in order to assure that adequate generation reserves are spinning before any sudden load change occurs.
- d. Telemetering for interconnection of shared or jointly-owned loads or generation commonly use dynamic signals. These signals are usually a calculated portion of an actual metered value. The calculation may include adjustments for losses, changing ratios of customer obligations or shares, or thresholds and limits. Two-way dynamic signals are used when a customer request for MW change can only be met by an actual change in generation. In this case, a return signal is the official response to the request and its integrated value is designated the official meter reading. Previous integration intervals were one hour. Some types of dynamic signals may require shorter integration intervals. The integration interval is determined by the type of service provided consistent with PGE tariffs to properly account for transmission usage.

2. Data Requirements for Control Area Services

Non-traditional sources are sometimes used for supplying ancillary services. If a load provides regulating or contingency reserve services, data requirements for deployment of the reserves will be similar to those applied to

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generating resources. To the extent that a third party may externally supply regulating or contingency reserve services at the PGE Control Area interconnecting boundary, data requirements for their deployment may be similar to those applied to generating resources.

Technical discussions are necessary before the specific data requirements can be determined. The following provides a brief overview of these requirements.

- a. If PGE is purchasing supplemental AGC services, AGC interface is required on a long-term basis. Prior to purchasing supplemental services, an investigation into the capabilities, cost, and benefits of AGC control is required to determine the specific AGC requirements. Most supplemental services are scheduled and delivered using dynamic signals.
- b. Ancillary Services requirements are also driven by how the interconnected customer chooses to meet these obligations. Either the Requester or the entity making the transmission arrangements is liable for the ancillary services obligations associated with the connection. Most self-provided ancillary services are scheduled and delivered using dynamic signals. The responsible party may fulfill these obligations in any of the following ways:
 - Self-provide ancillary services by making resources available to PGE to deploy.
 - Contract with a third party to make resources available to PGE to deploy.
 - Contract with PGE to cover this ancillary services obligation.
- c. Where a third party is providing ancillary services the following data is required with a sampling rate of once per second or other rate established by NERC:
 - Net instantaneous power transferred (MW)
 - Instantaneous and total MVAR transferred
 - Operating reserve capability during the next ten minutes
 - kWh for last hour

The Requester must demonstrate that the selected options are technically sound and meet all relevant reliability policies and criteria of NERC, WECC and NWPP or their successors.

3. Supervisory Control and Data Acquisition (SCADA) Requirements

Interconnection may require PGE SCADA control and status indication of the power circuit breakers and associated isolating switches used to connect with PGE. SCADA indication of real and reactive power flows and voltage levels are also required. If the connection is made directly to another utility's transmission system, SCADA control and status indication requirements shall be jointly determined with the Requester, and PGE. SCADA control of breakers and isolating switches that are located at other than the Connection Point is not normally required, although status indication may be necessary. Section 8-D discusses telecommunications requirements for SCADA systems.

7-C. Interchange Scheduling Requirements

A new load being integrated into the PGE System must adhere to the scheduling requirements of the prevailing tariff under which it is taking transmission service from PGE. Customers may be required to provide PGE Transmission Scheduling with an estimate of their hourly load, hourly generation schedules, and/or net hourly interchange transactions. These estimates will be used for both prescheduling and planning purposes. PGE will require customers to provide these estimates as necessary in order for PGE to manage the load/resource balance within the PGE Control Area and to determine usage of the PGE System.

In the case of new transmission facilities, scheduling and accounting procedures are needed if the facility is part of an interface between the PGE Control Area and another Control Area. This scheduling and accounting of interchange between two load control areas normally requires telemetered data from the Connection Point to the control centers of the load control area operators. This data is termed interchange metering and telemetering by PGE and includes kW and kWh quantities. PGE requires that all Control Area transactions be prescheduled for each hour using the normal scheduling procedures. The end-of-hour actual interchange must be conveyed each hour to the PGE Control Area Operator in the SCC. This can be accomplished through the use of telemetering or data link.

When the interconnection represents a shared or jointly owned interface to PGE, then a calculated allocation is usually required to divide up the total metered interchange. This non-physical interface is accomplished by dynamic signal. A two-way dynamic signal is required when a combined request and response interface is used. An example is supplemental AGC services. A one-way dynamic signal is required when a response (or following) interface is used. Moving a control area boundary is an example of this requirement.

1. Interchange Telemetering Requirements

Interchange telemetering generally consists of bi-directional meters and related telecommunications systems providing kW and kWh at or near the Connection Point. The kW measurement is telemetered on a continuous basis for AGC and hourly kWh is sent each hour to the Numbers accounting function. Table 7-1 summarizes telemetering requirements and Table 7-2 identifies different scenarios that require telemetering. Interchange telemetering accuracy and calibration requirements are identical with those stated in Sections 7-D and 7-E.

- Telemetering requires continuous knowledge of the quality of the meter reading. Associated with the telemetering signal are various indications of this quality.

2. Data Acquisition System

Loads such as steel rolling mills, wind tunnels, etc. require additional data to make generation control performance more predictable. Such additional data may include, but not be limited to, precursor signals of expected load changes, etc. SCADA control may also be required. Specific requirements and needs are determined for each load. Section 8-D discusses telecommunications requirements for telemetering and data acquisition.

7-D. Revenue and Interchange Metering System

All connections one kW or greater require PGE-qualified revenue or interchange metering and data recording for the PGE billing and/or scheduling processes. Revenue metering includes energy data (kWh) and reactive data (kVArh) produced by revenue meters and recorded on a one hour demand interval basis for interchange metering and 30 minute demand interval for customer load metering. Interchange metering includes bi-directional energy and reactive data as well as special telemetering requirements for scheduling purposes. The metering shall be located to measure the net power at the Connection Point to or from the PGE System.

The Revenue Metering System includes a remote metering system to record the hourly kWh data. The hourly kWh data is downloaded from the metering recorder on a periodic (typically weekly) basis over voice-grade telephone lines which may utilize cellular telephone. All recorders must be fully compatible with the PGE Billing Data Acquisition System. The system currently being used is the MV-90™. Demand data will be available to the customer or their agent.

PGE typically owns and maintains the revenue metering at load-metering sites. PGE will supply current and voltage transformers for revenue metering at customer owned substations. The customer will install these at his expense at locations agreed to with PGE. If the customer has bus voltage transformers for local metering and/or relaying, PGE will typically utilize these customer owned voltage transformers for revenue metering provided they meet the requirements in paragraph 3. When customer owned voltage transformers are utilized, PGE will be given exclusive use of one secondary winding for revenue metering. Any application other than revenue metering on the current transformer circuit or the voltage transformer circuit must be approved and installed by PGE. Loss compensation will be performed in the meter when required. In any case, PGE will provide the billing meters, accumulator and telemetry. In a customer owned substation the customer shall provide a two-way telephone circuit with protective equipment; or microwave or radio as agreed to with PGE.

1. Revenue and Interchange Metering Requirements

Three-element, three-phase, four-wire meters shall be used on grounded power systems. Revenue metering shall be bi-directional to record reactive flow to or from the Connection Point. The revenue-metering package includes a kWh recording device compatible with the PGE Revenue Metering System. Interchange metering shall be bi-directional in order to record both real and reactive flow at the Connection Point. The interchange metering package includes a kWh recording device compatible with the PGE scheduling system.

Should the new Connection Point result in the addition of generation to the PGE System not previously accounted for, there will be additional metering requirements. [Ref. 1.5]

Section 8-D discusses telecommunications requirements for the Revenue Metering System. Table 7-1 summarizes Revenue Metering requirements and Table 7-2 identifies requirements based on resource location.

2. Meter Accuracy

Meters shall be calibrated as specified in Table 3.

3. Instrument Transformers

Voltage and current instrument transformers shall be 0.3% accuracy class for both magnitude and phase angle over the burden range of the installed metering circuit. The instrument transformers shall be of a shielded design. This is a safety requirement to prevent unintentional energization of the transformer secondary during a transformer failure. Instrument transformers for metering need to be located such that the input to the metering and telemetering is not interrupted during possible switching configurations at the Connection Point. Instrument transformers will not be used as a source of station service power for operating equipment, heaters, receptacles or other uses that would normally be considered AC station service or battery loads.

4. Loss Compensation

Transmission system losses, such as those in transformer, often must be accounted for in the revenue metering process. This compensation will be done in the meters for new installations. Compensation will not be done in JEM-1™ meters used for Interchange Metering. Compensation in the JEM-1™ affects only the pulse integrator

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circuits (kWh), which disturbs the relationship between the direct analog outputs (kW) and the integrated pulse outputs (kWh).

5. Station Service Power

Depending upon its electrical source and electrical location, the station service power for the connecting substation facilities may also require Revenue Metering. It may not be necessary to meter station service VAR hours although most modern electronic meters include this feature as part of the meter. The other requirements of this section do apply to station service metering.

7-E. Calibration of Revenue and Interchange Metering Facilities

Revenue and Interchange Metering shall be calibrated every two years. Other calibration intervals may be negotiated. All interested parties or their representatives may witness the calibration tests. Calibration records shall be made available to all interested parties. The calibration standards used for calibration shall have their accuracy traceable to the National Institute of Standards and Technology. The calibration standard shall have been calibrated and certified within twelve months prior to the actual meter calibration.

Table 7-1 General Metering and Telemetry Data Requirements

System or Quantity	System Dispatching and Operations	Transmission Scheduling	Revenue Billing
kW	Yes	No	No ¹
kWh	Yes	Yes	Yes
kVAr	Maybe	No	No
kVArh	Maybe	No	Yes
kV	Yes	No	No
Load Size	≥ 1 MVA	≥ 1 MVA	≥ 1 kW
Data Sample Rate	kW: 1 second or other approved rate compatible with NERC Policy	Last Hour kWh sent each hour	Hourly kWh Data Retrieved periodically (RMS type system) ²
AGC	all Control Area boundaries & customer connections providing ancillary services	No	No
Tie Capacity	all normally closed ties	all normally closed ties	all ties

Notes

1. A kW reading for revenue billing may be required where special transmission arrangements are necessary.
2. Two-way dial-up phone line required for the RMS.

Table 7-2 Metering, Telemetry and SCADA Data Requirements vs. Connection Location

	Connection Located INSIDE PGE Control Area	Connection Located OUTSIDE PGE Control Area
Direct Electrical Connection to PGE System	kW, kWh, RMS, kVAr, kVArh, kV breaker status & control	kW, kWh, RMS, kVAr, kVArh, kV breaker status & control
NO Direct Electrical Connection to PGE System	kW, kWh, RMS	None

Note - Dedicated circuit is required for kW, kWh, kVAr, kVArh, and kV

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Table 7-3 Meter Calibration Requirements

Quantity Tested	Load	Angle	Tolerance	Calibration Required
WATTHOURS	LL	0 DEGREES	(+ / - 0.2 %)	ALWAYS
WATTHOURS	FL	0 DEGREES	(+ / - 0.2 %)	ALWAYS
WATTHOURS	FL	(- 30 DEGREES)	(+ / - 0.2 %)	ALWAYS
WATTHOURS	FL	(+ 30 DEGREES)	(+ / - 0.2 %)	ALWAYS
WATTHOURS	LL	(-180 DEGREES)	(+ / - 0.2 %)	NOT IF RADIALLY FED
WATTHOURS	FL	(-180 DEGREES)	(+ / - 0.2 %)	NOT IF RADIALLY FED
WATTHOURS	FL	(-150 DEGREES)	(+ / - 0.2 %)	NOT IF RADIALLY FED
WATTHOURS	FL	(-210 DEGREES)	(+ / - 0.2 %)	NOT IF RADIALLY FED
VARHOURS	FL	(-90 DEGREES)	(+ / - 0.2 %)	ALWAYS
VARHOURS	FL	(-30 DEGREES)	(+ / - 0.2 %)	ALWAYS
VARHOURS	LL	(-30 DEGREES)	(+ / - 0.2 %)	ALWAYS
VARHOURS	FL	(-150 DEGREES)	(+ / - 0.2 %)	NOT IF RADIALLY FED
VARHOURS	LL	(-150 DEGREES)	(+ / - 0.2 %)	NOT IF RADIALLY FED
VARHOURS	FL	(+ 90 DEGREES)	(+ / - 0.2 %)	ALWAYS
VARHOURS	FL	(+ 30 DEGREES)	(+ / - 0.2 %)	ALWAYS
VARHOURS	LL	(+ 30 DEGREES)	(+ / - 0.2 %)	ALWAYS
VARHOURS	FL	(+150 DEGREES)	(+ / - 0.2 %)	NOT IF RADIALLY FED
VARHOURS	LL	(+150 DEGREES)	(+ / - 0.2 %)	NOT IF RADIALLY FED

Notes

1. All angles given are in reference to the voltage applied.
2. Individual element tests using the above criteria shall also be performed when a meter is initially placed in service (new from factory).
3. Full load is defined as nominal voltage and 200% of meter test amp rating.
4. Light load is defined as nominal voltage and 20% of meter test amp rating.

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8. Telecommunication Requirements

8-A. Introduction

Telecommunications facilities shall be tailored to fulfill the control, protection, operation, dispatching, scheduling, and revenue metering requirements. At a minimum, telecommunications facilities must be compatible with, and have similar reliability and performance characteristics to, that currently used for operation of the power system at the Connection Point. Telecommunications facilities will be identified on the Project Requirements Diagram. Depending on the performance and reliability requirements of the control and metering systems to be supported, the facilities may consist of any or all of the following:

1. Microwave Systems

A microwave system requires transmitters, receivers, telecommunication fault alarm equipment, antennas, batteries, and multiplex equipment. It may also include buildings, towers, emergency power systems, mountaintop repeater stations and their associated land access rights, as needed to provide an unobstructed and reliable telecommunications path. Microwave path diversity, equipment redundancy, and/or route redundancy may be required to meet power system reliability requirements by protecting against telecommunications outage caused by equipment failure or atmospheric conditions.

2. Fiber Optic Systems

A fiber optic system requires light wave transmitters, receivers, telecommunication fault alarm equipment, multiplex equipment, batteries, emergency power systems, fiber optic cable (underground or overhead) and rights-of-way. Cable route redundancy may be required to protect against cable breaks and resulting telecommunications outage.

3. Wireline Facilities

A wireline facility requires telecommunications cable (underground or overhead), high-voltage isolation equipment and rights-of-way. It may also include multiplex equipment, emergency power systems, and batteries, depending on the wireline technology employed. Cable route redundancy may be required to protect against cable breaks and resulting telecommunications outage.

4. Power Line Carrier Current Systems

A power line carrier current system uses the actual power line conductor(s) as the transmission media. Coupling capacitors, line tuning units, and wave traps are connected to the circuit to connect the carrier transmitter and receiver to the power line. Power line carrier availability and performance is greatly affected by line outages. For this reason its use for control, data, and voice communications is limited. In some instances it can be used with line protective devices.

8-B. Telecommunications Availability

1. Common Carrier

Dedicated telecommunication facilities are required for the operation of Main Grid power system control and protection functions. Common carrier telecommunications systems may be considered, subject to reliability and availability requirements and capabilities.

2. Main Grid

Telecommunications systems serving Main Grid transmission systems shall be designed to an agreed upon availability criteria between PGE and the Requester.

3. Alternate Routing

If alternately routed telecommunications are required for Main Grid protective relaying schemes, then alternate routing requirements will be negotiated between PGE and the Requester.

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8-C. Voice Communications

If the Connection Point is within the PGE Control Area:

1. **Voice Communication** to the Connection Point operator is required whenever any type of telemetering is required.
2. **A Dedicated, Direct, Automatic Ringdown Trunk** (or equivalent) voice circuit between the appropriate PGE dispatchers and the Connection Point operator or dispatcher may be required for:
 - Loads of 50 MW or greater,
 - Eccentric (non-conforming) Loads
 - Connected networks that include automatic generation dropping for PGE Transmission system remedial action.
 - A non-radial interconnection to another electric utility with a transfer capability in either direction of 50 MW or greater.
3. **Independent Voice Communications** for coordination of system protection, control, and telecommunication maintenance activities between PGE and the Connection Point should be provided, in addition to the voice telecommunications specified.

8-D. Data Communications

Telecommunications for SCADA, RMS and Telemetering must function at the full performance level before and after any power system fault condition. Service continuity must be restored immediately after the fault without requiring any repair personnel activity.

1. **SCADA Requirements** typically include one or more dedicated circuits between the new Connection Point and the PGE transmission dispatching center.
2. **AGC Interchange and Control Telemetering** for operations and scheduling applications typically require one or more dedicated circuits between the new Connection Point and the appropriate PGE transmission dispatching center(s). Digital telecommunications capabilities from 1200 to 2400 baud rate are required. In rare circumstances, the Interutility Data Exchange Network could be used for AGC purposes upon the agreement of both parties. This would be for very small and/or radial interchanges and generation quantities. These situations may require a NERC waiver. (For these rare circumstances, refresh times as slow as one minute may be acceptable.)
3. **General Telemetering** for kWh and data acquisition systems typically require one or more dedicated circuits between the new Connection Point and the appropriate kWh or data acquisition system master computer.

4. **Revenue Metering System** remote equipment require commercial ‘dial-up’ telephone exchange line facilities to communicate with the master computer at the PGE System Control Center. The circuit used for this purpose may also be shared with voice communications and other dial-up data communications.

8-E. Telecommunications for Control and Protection

Telecommunications for Control and Protection must function at the full performance level before, during, and after any power system fault condition. The delivery of a false trip or control signal, or the failure to deliver a valid trip signal is unacceptable. Active telecommunication circuits for control and/or protection must not be tested, switched, shorted, grounded or changed in any manner by any worker, unless prior arrangements have been made through the PGE Outage Dispatcher.

1. Main Grid Transmission

New connections to the PGE Main Grid, and connections which require remedial actions on the PGE System, may require redundant (i.e. hot-standby or frequency-diversity) telecommunications systems. Alternately routed telecommunication circuits may be used where feasible (to be negotiated between PGE and the Requester).

2. Secondary Transmission.

New connections to the PGE secondary grid transmission generally do not require redundant telecommunications systems. However, under some circumstances, redundant telecommunications are required to satisfy stability criteria.

3. Speed of Operation

Throughput operating times of the telecommunications system must not add unnecessary delay to the clearing or operating times of protection or remedial action schemes. Maximum permissible throughput operating times of control schemes are determined by system studies.

4. Equipment Compatibility

In order to provide maintainability and operability between the new connection and the PGE System, the protection systems and their supporting telecommunications system equipment (teleprotection) do not have to be identical but must be functionally compatible. The need or implementation of peripheral capabilities such as signal counters, test switches, etc. are not required to be identical to those used at PGE facilities. During initial engineering of the new connection request, PGE and the Requester will confirm the communications equipment is compatible between the PGE and Requester systems. Should the Requester choose to use something other than what has been agreed to by PGE, PGE reserves the right to test the equipment system compatibility, prior to installation, at the Requester’s expense.

PGE will acknowledge the use of alternative equipment and/or technologies as proposed by the Requester as long as the equipment is suitable for the purposes of the control application required. The teleprotection systems, including transfer trip, must be engineered and tested to demonstrate that they perform their intended functions. When applying sophisticated digital telecommunications systems to certain protection schemes, care must be taken to avoid combining approaches with inherent technical conflicts or incompatible methodologies.

8-F. Telecommunications during Emergency Conditions

1. Emergency Conditions

The previous requirements address the availability and redundancy for telecommunications systems and equipment to assure reliable operation of the PGE System under normal telecommunications conditions. Normal conditions for telecommunications include both normal and emergency conditions for the transmission system. However, emergency conditions may develop that affect power system telecommunications with or without directly affecting power transmission system facilities.

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Examples of telecommunications emergencies include the following:

- Interruption of power service to telecommunications repeater and relay stations
- Telecommunications equipment failure, whether minor or catastrophic
- Interruption or failure of commercial, public telephone network facilities or services
- Damage to telecommunications facilities resulting from accident, acts of vandalism, or natural causes

Equipment redundancy and telecommunications route redundancy can protect against certain kinds of failure and telecommunications path interruption. A dedicated telecommunications repair team should be maintained along with an adequate supply of spare components.

2. Backup Equipment

Where commercial, public telephone network facilities or services support important power system telecommunications, a backup strategy should always be developed to protect against interruption of such services. Backup methodologies could include redundant services, self-healing services, multiple independent routes and/or carriers, and combinations of independent facilities such as wireline and cellular, fiber and radio, etc. Backup telecommunications system equipment such as emergency standby power generators with ample on-site fuel storage, and reserve storage battery capacity must be incorporated in critical telecommunications facilities. Backup equipment should be considered as well for certain non-critical telecommunications to assure continued operation of power system telecommunications during interruption of power services.

3. Disaster Recovery

A disaster recovery plan should be in place for telecommunications restoration, and should be exercised periodically. The disaster recovery plan should include the ability to deploy transportable restoration equipment capable of temporarily bypassing or replacing entire telecommunication stations or major apparatus until permanent repairs can be made.

4. Telecommunications Security

The operation of power system telecommunications facilities should be continuously monitored at a central alarm point so that trouble can be immediately reported, diagnosed, repaired and service restored. Power system telecommunication sites and facilities should be secured against unauthorized access by means of locked gates, security fences, warning signs, security doors, and entry alarms.

9. Definitions

For the purposes of this document the following definitions apply:

ACE – Area Control Error is the instantaneous difference between net actual and scheduled interchange, taking into account the effects of frequency bias including a correction for meter error.

Active Power - The component of total volt-amperes in an electric circuit where the voltage and current are in phase. It is also called real power and is measured in watts (W), kW or MW. This is the electrical power associated with useful energy, including mechanical work and heat. Active power used or transmitted over time is measured in kilowatt-hours (kWh) or MWh.

Ancillary Services - The term used by FERC to describe the special services that must be exchanged among generation resources, load customers and transmission providers to operate the system in a reliable fashion and allow separation of generation, transmission and distribution functions. These include: 1) scheduling, system control and dispatch, 2) reactive supply and voltage control from generators, 3) regulation and frequency response, 4) energy imbalance, 5) spinning reserves, and 6) supplemental reserves. Most of these services are included in a similar set by NERC and termed Interconnected Operations Services, which also include load following and black start capability.

***WECC Definition:** Interconnected Operations Services identified by the U.S. Federal Energy Regulatory Commission (Order No. 888 issued April 24, 1996) as necessary to effect a transfer of electricity between purchasing and selling entities and which a transmission provider must include in an open access transmission tariff.*

Automatic Generation Control (AGC) System - A system that measures instantaneous loads at interchange points (boundaries with adjacent Control Area) and adjusts generation to follow load. It consists of continuous, real time load signals (kW), telemetered to AGC computers at a transmission control center.

***NERC Definition:** Equipment which automatically adjusts a Control Area's generation from a central location to maintain its interchange schedule plus frequency bias.*

Baud Rate – A unit of signaling speed equal to the number of discrete conditions or signal events per second, or the reciprocal of the time of the shortest signal element in a character.

Bi-directional Metering - Measures kWh and kVArh flowing in both directions ('in' and 'out' kWh and leading and lagging reactive).

Blackstart Capability - The ability of a generating plant to start its unit(s) with no external source of electric power. (WECC)

Bottleneck – A location in the transmission system where line or equipment ratings limit transfer capabilities. These situations may require special operating practices to avoid overloads under certain system conditions.

Connection Point - The location on the PGE System where a new connection is established to serve a load or connect a line to another electrical system.

Demand - The rate at which energy is being used by a customer. (NERC)

Directional Relay - A relay that responds to the relative phase position of a current with respect to another current or voltage reference.

Distribution – The lower voltage lines and equipment directly serving electrical consumers. This is generally a radial circuit, operating at voltages at or below 57 kV. The term 'distribution' may also be used to refer to equipment operating at or below 57 kV.

Disturbance - An unplanned event that produces an abnormal system condition. (WECC)

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Dynamic Schedule - A telemetered reading or value which is updated in real time and which is used as schedule in the automatic generation control and area control error equation (AGC/ACE) and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for 'scheduling' jointly owned generation to or from another control area.

Dynamic Scheduling Service - Provides the metering, telemetering, computer software, hardware, telecommunications, engineering, and administration required to electronically move a transmission customer's generation or demand out of the Control Area to which it is physically connected and into a different Control Area.

Dynamic Signal - A telemetered reading or value that is updated in real time, and which is used either as a tie line flow or as a schedule in the AGC/ACE equation (depending on the particular circumstances). Common applications of dynamic signals include 'scheduling' jointly owned generation to or from another control area and to move control area boundaries. Another application provides for an entity to request (schedule) a change in power flow. The resulting response is telemetered to the entity signifying the actual movement of a resource. This form of dynamic signal is applied to supplemental control area services. The integrated value of this signal is used for interchange accounting purposes, as appropriate.

Eccentric (Non-Conforming) Loads - Any cyclic load with the ability to change periodically by more than 50MW at a rate of greater than 50MW per minute, regardless of the duration of this change.

Effectively Grounded - A system that provides an $X_0/X_1 < 3$ & $R_0/X_1 < 1$ where X_0 and R_0 are zero sequence reactance and resistance respectively, and X_1 is positive sequence reactance.

Fault - A short circuit on an electrical transmission or distribution system between phases or between phases(s) and ground, characterized by high currents and low voltages.

Feeder - A radial electrical circuit, generally operating at or below 57 kV serving one or more customers.

FERC - Federal Energy Regulatory Commission

Ferroresonance - A phenomenon usually characterized by overvoltages and very irregular voltage and current wave shapes and associated with the excitation of one or more saturable inductors through capacitance in series with the inductor (IEEE). A condition of sustained waveform distortion and overvoltages created when a relatively weak source of voltage energizes the combination of capacitance and saturable transformers. A sufficient amount of damping, or resistance, in the circuit usually controls or eliminates the phenomenon.

Hybrid Switching - A variation of single-pole switching that is used on long lines to extinguish the secondary arc of single line-to-ground faults. The faulted phase is detected and opened first via single-pole relaying. After approximately fifty cycles the two unfaulted phases are opened to extinguish the secondary arc. Three-phase automatic reclosing follows.

IEEE - Institute of Electrical and Electronic Engineers

Interchange Metering - Metering at interchange points between two controlling utilities. Consists of AGC (continuous kW) telemetering and hourly kWh (on-the-hour hourly load kWh). These quantities must go to both controlling utilities so they can manage their respective Control Areas.

Interchange Point - Locations where power flows from one Control Area to another (i.e. connection between two controlling utilities).

Island - A portion of the interconnected WECC system that has become isolated due to the tripping of transmission system elements. 'Local' Island - A portion of the transmission system, often a single line, that is isolated from the

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main system and energized by a local generator. Generally, system islands do not have a stable generation-resource balance.

ISO – Independent System Operator

Control Area - 1. The electrical (not necessarily geographical) area within which a controlling utility has the responsibility to adjust its generation to match internal load and power flow across interchange boundaries to other Control Areas. 2. A resource or portion of a resource that is scheduled by a specific utility. If the utility schedules the resource, the resource becomes part of its Control Area. Physical location of the Connection Point does not determine its Control Area.

***WECC Definition:** A system which regulates its generation in order to maintain its interchange schedule with other Control Areas and contributes its frequency bias obligation to the interconnection.*

NERC - North American Electric Reliability Council is a not-for-profit company formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of nine Regional Reliability Councils, one of which is the Western Systems Coordinating Council.

Non-spinning Reserve - That portion of the operating reserve capable of being connected to the bus and loaded within ten minutes. Also included is any load that is designated for use as reserve and can be reduced by dispatcher action within ten minutes. (WECC)

NWPP - Northwest Power Pool

OASIS – Open Access Same-Time Information System is an electronic posting system for transmission access data that allows all Transmission Customers to view the data simultaneously.

Operating Reserve - That reserve above firm system load capable of providing for regulation within the hour to cover load variations and power supply reductions. It consists of spinning reserve and non-spinning reserve. (WECC)

***NERC Definition:** Provides additional capacity from electricity generators that are on line, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur.*

Phase Unbalance - The percent deviation of voltage or current in one phase as compared to the average of all three phases.

Pilot Protection - A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line. (IEEE) The communication channel may be power line carrier, microwave or other radio, fiber optics, leased telephone line or a dedicated hardwire circuit.

Portland General Electric (PGE System) - The transmission facilities owned or controlled by PGE.

Power Factor - The ratio of real power in watts to the product of volts times amperes in an alternating current circuit. The power factor is unity when the voltage and current are in phase. A ‘lagging’ power factor is associated with a partially or wholly inductive load that ‘absorbs’ positive reactive power. A ‘lagging’ power factor is also associated with a generator that ‘delivers’ positive reactive power. A ‘leading’ power factor is associated with a capacitive load that ‘delivers’ or a generator that ‘absorbs’ positive reactive power. See reactive power.

Power System - The integrated electrical generation and transmission facilities owned or controlled by one electric utility organization. (WECC)

Prudent Electric Utility Practices or ‘Prudent Utility Practice’ - The generally accepted design, practices, methods, operation and maintenance of a power system, to achieve safety, dependability, efficiency, and economy, and to meet utility and industry codes, standards, and regulations.

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Pseudo-Tie - A telemetered reading or value that is updated in real time and used as a tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. It usually represents a portion of an actual metered flow. The integrated value is used as a metered megawatthour (MWh) value for interchange accounting purposes. A pseudo-tie is one form of dynamic signal.

Radial Line - A transmission line that is connected to the transmission network only at one end. More typically, a distribution line where only one end connects back to the network and loads are served at the other end and along the line.

Rating Criteria – The assumptions used for rating PGE transmission line facilities are: 2.93 ft/sec wind speed, 40°C summer ambient temperature, 0°C winter ambient temperature, 75°C conductor temperature for copper, AAC and ACSR conductors under normal operation, 93°C conductor temperature for AAC conductors under emergency operation and 100°C conductor temperature for copper and ACSR under emergency operation.

Reactive Power - The component of total volt-amperes in an alternating current circuit where the voltage and current are out of phase by ninety electrical degrees. It is measured in units of volt-amperes reactive (VAr), kVAr or MVAr. It represents the power involved in the alternating exchange of stored energy in inductive and capacitive electromagnetic fields. Although this type of power supplies no useful energy, it is an inherent requirement for all alternating current power systems. By convention, positive reactive power is 'absorbed' by an inductance and 'generated' by a capacitance. Reactive power transferred over time is measured in VAr-hours (VArh). See power factor.

Real Power - The component of total volt-amperes in an electric circuit where the voltage and current are in phase. It is also called active power and is measured in watts (W), kW or MW. This is the electrical power associated with useful energy, including mechanical work and heat. Real power used or transmitted over time is measured in kilowatt-hours (kWh) or MWh.

Real Time - Data reported as it happens, with reporting (update) intervals no longer than a few seconds. Applies to AGC type data, but not to kWh or RMS data, which are accumulated and reported only when queried by a master station.

Remedial Action - Special pre-planned corrective measures which are initiated following a disturbance to provide for acceptable system performance. (WECC)

Remedial Action Scheme (RAS) - A protection system that automatically initiates one or more control actions following electrical disturbances. Also called 'Special Protection System.' (WECC) Typical examples are generating dropping, load tripping, shunt capacitor switching and shunt reactor switching.

Requester - An electrical utility or other customer or their representative that is requesting a new connection to the PGE Transmission System.

Revenue Metering - General term for metering which is calibrated to ANSI Standards for Billing Accuracy.

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Single Pole Switching (SPS) - The practice of tripping and reclosing one pole (phase) of a three pole circuit breaker without changing the state of the remaining poles. Tripping is initiated by single-pole relays that respond selectively to the faulted phase. Notes: 1) Circuit breakers used for single pole switching must inherently be capable of independent pole opening. 2) In most single pole switching schemes it is the practice to trip all poles for any fault involving more than one phase. (IEEE)

Spinning Reserve - That portion of the operating reserve which is synchronized to the system, responds automatically to fluctuations in system frequency, and is capable of assuming load up to the cited spinning reserve magnitude within ten minutes. (WECC)

Station Service - The electric supply for the ancillary equipment used to operate a generating station or substation. (NERC)

Supervisory Control and Data Acquisition (SCADA) - A system of remote control and telemetering used to monitor and control the transmission system. (NERC)

Tap Line – A line that connects to an existing transmission or distribution line without breakers at the tap point, resulting in an additional terminal on the existing line.

Telemetering - Continuous, real time data reporting, as for AGC and Generation kW (but not for kWh or Revenue Metering Systems, which are not continuously reported).

NERC Definition: The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted using telecommunication techniques.

Three-Pole Switching - A relay system and corresponding switchgear that trips or opens all three poles (phases) regardless of fault type.

Wheeling - Transmitting power from one point to another within a Control Area or between Control Areas.

WECC - Western Systems Coordinating Council

For industry standard definitions of electric industry terminology, please refer to:

The New IEEE Standard Dictionary of Electrical and Electronic Terms,
IEEE Std 100-1992.

10. References

1. ANSI – IEEE - NFPA
 - 1.1 ANSI/IEEE Std 80 - *Guide for Safety in AC Substation Grounding*
 - 1.2 IEEE Std 81 Part 1 - *Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Ground System & Part 2: Guide for Measurement of Impedance and Safety Characteristics of Large, Extended or Interconnected Grounding Systems.*
 - 1.3 IEEE Std 100 - *IEEE Standard Dictionary of Electrical and Electronic Terms.*
 - 1.4 IEEE Std 367 - *Recommended Practice for Determining the Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault*
 - 1.5 IEEE Std 519 - *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*
 - 1.6 IEEE - 487 - *Recommend Practice for the Protection of Wire-Line Communication Facilities Serving Electric Power Stations*
 - 1.7 IEEE - 837 - *Standard for Qualifying Permanent Connections Used in Substation Grounding*
 - 1.8 NESC C2 - *National Electrical Safety Code*
 - 1.9 ANSI C84.1 – *Electric Power System and Equipment – Voltage Ratings (60Hz)*
 - 1.10 NFPA 70 - *National Electrical Code*
2. NERC – NWPP - WECC
 - 2.1 NERC *Operating Standards*
 - 2.2 NERC *Planning Standards*
 - 2.3 NWPP *Operating Manual*
 - 2.4 WECC Reliability Criteria including:
 - 2.4.1 *Reliability Criteria for System Design*
 - 2.4.2 *Power Supply Design Criteria*
 - 2.4.3 *Minimum Operating Reliability Criteria.*
 - 2.4.4 *Reliability Management System*
3. Portland General Electric – T&D Design and Construction Standards

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11. Connection Request Form

TRANSMISSION/END-USER CONNECTION REQUEST

INFORMATION:

This application will be used by the PGE to perform Preliminary Studies to determine the Interface requirements at the customer's Point of Interconnection. The applicant should attempt to fill in as much of the form as possible.

SECTION 1: PROJECT OWNER/PROJECT SPONSOR INFORMATION

Project Owner		Project Sponsor/Engineer	
Company		Company	
Contact		Contact	
Mailing Address:		Mailing Address:	
City/County/State/ 9 Digit Zip Code		City/County/State/ 9 Digit Zip Code	
Phone Number		Phone Number	

ELECTRICAL CONTRACTOR (as applicable)

Company			
Mailing Address			
City	County	State	9 Digit Zip Code
Phone Number		Contact	

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SECTION 2: PRELIMINARY REVIEW INFORMATION

Type of connection

- Radial Load
- Network Connection with Other Sources Present

Comments:

Connection Point

Identify the PGE Line or Substation

Type of Load

Identify the characteristics which best describe the type of load to be served (more specific information may be required for loads such as those associated with arc furnaces, large motor, etc.)

Load Data (at the time of energization and every year for 10 years)

Projected Peak Load	Summer Peak Load	Winter Peak Load	Anticipated Power Factor
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Future Plans (Where known)

Modification or changes affecting the connection or connected equipment

SECTION 3: STUDY DATA REQUIREMENTS

One Line Diagram

Attach Diagram

Network Power Flow Model

Enclose a network power flow model using GE or PTI format

LINE DATA

Positive Sequence

Resistance (ohms/mile)

Reactance (ohms/mile)

Susceptance (mhos/mile)

Zero Sequence

Resistance (ohms/mile)

Reactance (ohms/mile)

Susceptance (mhos/mile)

Conductor Rating (amperes @ °C temperature rise) and Conductor Type

Line Length (miles)

System Data

Provide a system equivalent (R1,X1,R0,X0 in per unit on a 100 MVA base) at the proposed Connection Point looking into the connecting system. This values should be determined such that the system model *does not* include the physical connection to the PGE System. Assuming there are no other connections to the PGE System at any other point, these quantities are available by computing a single line-to-ground 'bus fault' at the proposed Connection Point.

Reactive Equipment

Location, size, and rated voltage

To be filled out by the PGE Transmission and Reliability Services Representative:

PGE Representative

Location

Internal Routing

Phone Number

Copy of Connection Request and Attachments to:

- Manager, Transmission and Reliability Services
- Manager, System Planning and Engineering
- Manager, Customer Account Management

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