Bonneville
POWER ADMINISTRATION

Technical Requirements for Interconnection to the BPA Transmission Grid
STD-N-000001, Revision 05

Standard/Technical Content Owner: TPP/TPC

DISTRIBUTION STATEMENT: Approved for public release; distribution is unlimited.

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1. INTENT

The Bonneville Power Administration, Transmission Services (TS) prepared this *Technical Requirements For Interconnection To The BPA Transmission Grid* document to identify technical requirements for connecting transmission lines, loads and generation resources into the BPA Grid. Also included are the Balancing Authority Area (BAA) requirements for generation connected to a utility system located within BPA's BAA. The purpose of these requirements is to assure the safe operation, integrity and reliability of the BPA Grid.

This document is not intended as a design specification or an instruction manual. The information presented is expected to change periodically based on industry events and evolving standards. Technical requirements stated herein are consistent with BPA's current internal practices for system additions and modifications. These requirements are generally consistent with principles and practices of the North American Electric Reliability Corporation (NERC), Western Electric Coordinating Council (WECC), Northwest Power Pool (NWPP), Institute of Electrical and Electronics Engineers (IEEE) and American National Standards Institute (ANSI). Standards of the above listed organizations are also subject to change. The most recent version of such standards shall apply to each interconnection request.

Contractual matters, such as costs, ownership (see STD-N-000011), scheduling, and billing are not the focus of this document. Official requests for Interconnections or Transmission Service are not addressed by this document. BPA's Open Access Transmission Tariff governs the commercial aspects of interconnections and transmission service. Please refer to the BPA web site, www.bpa.gov, or contact a TS Account Executive for more information on the interconnection process, business practices, contractual matters or transmission services. Refer to the Large Generator, Small Generator and Line/Load procedures and business practices for additional information.

http://www.transmission.bpa.gov/business/generation_interconnection/

Requests to interconnect generating resources or loads (Projects) are typically submitted by the project developer but may be made in conjunction with what Transmission Services refers to as a "Host Utility", a utility located within BPA's Balancing Authority Area. BPA refers to the entity that submits the interconnection request as the Requester. BPA evaluates and studies each Project individually, as it was described in the request and determines impacts to BPA transmission facilities and, if applicable, impacts to neighboring affected systems.

This document also addresses interconnection through another utility that may not result in a direct interconnection to the BPA Grid. Through telemetering and communications interconnections, BPA may incorporate loads, generators or transmission lines into the BPA Balancing Authority Area. This type of interconnection, which uses dynamic signals and telemetering, may transfer ancillary services from one party to another.

Interconnection evaluations and studies usually result in a proposed plan of service for physical and communications interconnections. Physical laws that govern the behavior of electric systems do not recognize boundaries of electric facility ownership. Therefore the electric power systems must be studied, without regard to ownership, to develop a properly designed interconnection. The completed review may include studies of short-circuit fault duties, transient voltages, reactive power requirements, stability requirements, harmonics, safety, operations, maintenance and prudent electric utility practices.

In this document, the terms BPA, BPA Balancing Authority Area, BPA Grid, etc. all refer only to the BPA Transmission Services organization and transmission system, not to the BPA Power Services (PS) organization. An interconnection request from BPA Power Services is handled in the same manner as from any other Requester. The term ”Requester” describes the utility, developer or other entity that requests a new or modified connection for a line, load or generation interconnection. The proposed interconnection may be directly to BPA’s transmission system, or to another utility’s system that is located within BPA’s Balancing Authority Area.

These technical requirements generally apply to all new or modified interconnections to the BPA Grid and telemetered balancing authority area interconnections. The location and type of the facility, and impacts on the BPA Grid or another utility’s system determine the specific requirements. The interconnection must not degrade the safe operation, integrity and reliability of the BPA Grid. The interconnection requirements are intended to protect BPA facilities, but cannot be relied upon to protect the Requester’s facilities.

1.1 Applicable Codes, Standards, Criteria and Regulations

To the extent that the codes, standards, criteria and regulations are applicable, the new or modified facilities shall be in compliance with those listed in the Reference section.

1.2 Effect of the National Environmental Policy Act

Federal law requires that BPA comply with the National Environmental Policy Act (NEPA). BPA cannot commit to construction or interconnection agreements until its NEPA requirements are satisfied.

1.3 Safety, Protection, and Reliability

BPA will make the final determination as to whether the BPA facilities are properly protected before an interconnection is energized. The Requester or interconnecting utility is responsible for proper protection of their own equipment and for correcting such problems before facilities are energized or interconnected operation begins. BPA may determine equivalent measures to maintain the safe operation and reliability of the BPA Grid. For most generators and some loads, this will include BPA capability for direct tripping through special protection schemes. In situations where there is direct interconnection with another utility’s system, the requirements of that utility also apply.

1.4 Responsibilities of the Parties

BPA, the Requester and if applicable, the interconnecting utility, are each responsible for the planning, design, construction, compliance with applicable statutes, reliability, protection, and safe operation and maintenance of their own facilities unless otherwise identified in the construction, operation and/or maintenance agreements.

1.5 Special Disturbance Studies

BPA uses series and shunt capacitors, shunt reactive devices, 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 interconnected facilities. This may include the possibility of electro-mechanical resonance between a generator and the power system, or large angle changes when considering high-speed reclosing. BPA conducts studies of interconnection impacts to BPA facilities at the Requester's expense. The Requester is solely responsible for any additional studies necessary to evaluate possible stresses on their equipment and for any corrective actions.

1.6 Cost Estimates

BPA develops application-specific cost estimates as part of the interconnection studies since each interconnection is different and causes different impacts to BPA facilities. Cost estimates progress with study development, from typical estimates used in the feasibility and system impact stages, to budget quality cost estimates used for business case and work order approval.

2. REVISION HISTORY

- Revision 05 (Current Revision), 09/28/2016: Removed ownership of last span and corresponding demarcation and design requirements and referenced new STD-N-000011. Corrected Generators Section 6.3.3 to show large generation is greater than 20 MW, not greater than or equal. Updated overall format. General language improvements. Removed outdated references to NERC/WECC Planning Standards. Updated and aligned figure and table numbering.
- Revision 04, 09/29/2015: Added ownership of last span and corresponding design requirements and references. In addition, updated (formerly) Section 7 for consistency with the updates to (formerly) Section 8 as well as more consistent reflection of actual practice.
- Revision 03, 11/6/13: General updates, re-organized document.
- Revision 02, 8/26/11: Added requirements for integration of typical wind-generation facilities.
- Revision 01, 3/20/2009: Updated to include latest technical standards and requirements. Adopted as BPA Standard number STD-N-000001.

- Revision 00, 6/15/2005: Original issue. Replaces and supersedes BPA documents DOE/BP-3162 and DOE/BP-3183.

3. DEFINITIONS

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

The Authoritative Dictionary of IEEE Standards Terms, IEEE 100.

For the purposes of this document the following definitions apply:

Active Power: The ‘real’ component of complex power carried by an alternating-current circuit, produced by mutually-in-phase components of voltage and current waveforms. Active power can be calculated as the product of apparent power and the power factor. Measured in units of watts (W), kW or MW, active power is associated with useful work, including mechanical work and heat. Active power used or transmitted over time is energy, measured in kilowatt-hours (kWh) or megawatt-hours (MWh.). Also known as ‘real power’. See also ‘power factor’.

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 dispatching, 2) reactive power 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 affect a transfer of electricity between purchasing and selling entities and which a transmission provider must include in an open access transmission tariff.

Refer to BPA’s open access transmission tariff for further information on how the term is applied at BPA.

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

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.

Balancing Authority Area: A term adopted by FERC, NERC and WECC to replace "Control Area".

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.

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: An area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas, and contributing to frequency regulation of the interconnection.

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

BPA Dispatcher: The BPA Dispatcher or system operator is the ultimate authority on all operations, switching, etc. that can affect the BPA Grid. The BPA Dispatchers work 24/7 in two control centers located at Mead and Vancouver, Washington.

BPA Grid: The transmission facilities owned or controlled by Bonneville Power Administration, Transmission Services.

Control Area: See definition for "Balancing Authority Area".

Coordinated Voltage Control (CVC): Using AGC data links to the power plant, BPA will request a power plant to deviate from the published time-of-day high side bus voltage schedule to coordinate closely coupled power plants to operate at the same power factor. By minimizing circulating var flow between power plants, all power plants will minimize their var production requirements. The CVC program runs once every two-minutes. It is a slow adjustment of voltage schedules and is not intended to replace the function of the automatic voltage regulator. Closely coupled power plants are determined by incrementing and decrementing the bus voltages 0.01 pu in a power flow study. Plants that show significant response by a change in var production are considered closely coupled. Examples include: Chief Joseph and Grand Coulee 230 kV and 500 kV; Centralia and Big Hanaford and Chehalis 500 kV; John Day and Boardman and Coyote Springs and Calpine Hermiston 500 kV and McNary and US Gen 230 kV.

Directional Relay: A relay that responds to the relative phase position of a current with respect to another current or voltage reference, with the intent of distinguishing the direction of the fault location.

Distribution: That part of the electric grid associated with delivery of energy to customers. Distribution-level nominal voltages are generally considered to be 34.5 kV or lower. The set of distribution facilities owned, leased, or operated by BPA is not extensive, and BPA policy is to sell low voltage delivery facilities to distribution utilities whenever possible.

Disturbance: An unplanned event that produces an abnormal system condition. (WECC definition) The most common disturbances are: (a) faults with subsequent tripping of a transmission line or distribution feeder and (b) loss of a generator with subsequent temporary system frequency decrease.

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 $X0/X1<3$ & $R0/X1<1$ where X0 and R0 are zero sequence reactance and resistance respectively, and X1 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 69 kV serving one or more customers.

FERC: Federal Energy Regulatory Commission On-line at www.ferc.gov.

Ferroresonance: A phenomenon usually characterized by overvoltages and very irregular wave shapes and associated with the excitation of one or more saturable inductors through capacitance in series with the inductor. (IEEE definition). 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.

Generation Site: The geographical location of the Project generator(s) and local generator equipment. This may be near or far from either the Point of Interconnection or the Interconnecting Substation.

Harmonic: A sinusoidal component of a periodic wave or quantity having a frequency that is an integer multiple of the fundamental frequency. (IEEE definition) Harmonics can damage equipment, cause misoperation of relays, and can interfere with communications. Thus, they are an important aspect of power quality, and must be controlled by filtering or other methods.

Host Control Area: A control area that is operated by an authority other than BPA which does not overlap with the BPA Control Area.

Hybrid Single Pole 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, consisting 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).

Inter-Control Center Communications Protocol (ICCP): Inter-Control Center Communication Protocol (ICCP) is an international standard communications protocol for real time data exchange. The ICCP is defined in the international standard IEC 870-6 TASE.2.

Island, intentional: A utility practice to deliberately isolate a portion of its distribution line to use local generation to serve load during an outage of the transmission system.

Island, unintentional: A portion of an interconnected system that becomes isolated due to a fault clearing or RAS action, resulting in a portion of the transmission system divided split into isolated load and generation groups.

Main Grid: BPA's Main Grid transmission facilities include all 500 kV lines, 345 kV lines, as well as some lower voltage lines and supporting facilities (e.g., transformers) that carry bulk power within the Northwest. Main grid lines and equipment include the most critical equipment to the reliability of the BPA Grid.

MV-90™: The Multi-Vendor Translation System interprets a variety of metering communication protocols used for data collection and analysis. Data is retrieved over dial-up (voice grade) telephone lines by the MV-90™ master located at the BPA Control Center. The master automatically polls the remotes daily can be used to poll a remote at any time. In addition to polling raw impulses from the recorders, MV-90™ can perform data validation, editing, reporting and historical database functions.

NERC: North American Electric Reliability Council is a not-for-profit corporation formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of 10 Regional Reliability Councils, one of which is the Western Electricity Coordinating Council. On-line at www.nerc.com .

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.

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

Pilot Protection (Pilot Telecommunications): A communications signal between two protective relay terminals used to provide a trip signal between terminals. The communication channel may be power line carrier, microwave (or other radio-based) path, fiber optic circuit, leased telephone line, or a dedicated hardwire circuit.

Point of Interconnection (POI): The physical location on the power system at which Requester-owned facilities connect to those owned by BPA, defining the ‘change of ownership.’

Power Factor: The dimensionless ratio of active power to apparent power in an alternating-current (ac) circuit. The power factor can range only between unity (with voltage and current mutually in phase), and zero (with voltage and current 90 electrical degrees mutually out of phase). A condition of ‘lagging’ power factor occurs when active power and reactive power propagate in the same direction – e.g., with inductive loads, which always consume reactive power; or with generators, when delivering reactive power. A condition of ‘leading’ power factor occurs when active power and reactive power propagate in opposite directions – e.g., with capacitive loads, which always delivers reactive power; or with generators, when consuming reactive power. For generators, operation with a lagging power factor is called an ‘overexcited’ condition; a leading power factor implies ‘under excited’ operation. Power factor is the cosine of the electrical angle between the voltage and current.

Power System: Integrated electrical power generation, transmission and distribution facilities.

Power System Stabilizer (PSS): A device that provides an additional input to the exciter of a generator to provide damping of power system oscillations and improve system stability.

Project: Non-BPA owned facilities included in the interconnection request.

Project Requirements Diagram (PRD): A BPA simplified drawing showing the electrical requirements for the connection of a generator, a transmission line or a load to the BPA Grid. The PRD consists of one or more pages that may include a connection diagram of the 60 Hz high voltage equipment, telecommunications and data requirements, and remedial action scheme (RAS) requirements.

Reactive Power: The ‘imaginary’ component of complex power carried by an alternating-current circuit, produced by components of voltage and current waveforms that are mutually out of phase by 90 electrical degrees. Reactive power can be calculated as the product of apparent power and the sine of the power factor angle. Measured in units of volt-amperes reactive (var), Kvar or Mvar, reactive power is associated with the alternating exchange of stored energy between electric and magnetic fields. Although reactive power does no useful work, it is inherently required for operating any alternating-current power system or HVDC converter. By convention, reactive power is absorbed or consumed by an inductance and generated or produced by a capacitance. Reactive power transmitted over time is measured in var-hours (varh). See also ‘power factor’.

Real Power: See ‘Active Power’.

Real-Time: Data reported as it happens, with reporting (update) intervals no longer than a few seconds. Real-time 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 Scheme (RAS): A protection system that automatically initiates one or more control actions following electrical disturbances. Also referred to as ‘Special Protection System.’ Typical examples include tripping generators or loads and switching of series capacitors, shunt capacitors or shunt reactors.

Requester: An electrical utility or other customer or their representative that is requesting a new connection to the BPA Grid.

Reserve:

- 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.
- Spinning Reserve: Unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating Reserve and Contingency Reserve.
- Regulating Reserve: An amount of operating reserve sufficient to reduce Area Control Error to zero in ten minutes following loss of generating capacity, which would result from the most severe single contingency. At least 50% of this operating reserve shall be Spinning Reserve, which would automatically respond to frequency deviation.
- Nonspinning Reserve: That operating reserve not connected to the system but capable of serving demand within ten minutes, or interruptible load that can be removed from the system within ten minutes.

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

Revenue Metering System (RMS): Provides hourly data daily (as compared to kWh system that reports hourly load each hour). A meter and recording device are installed at points where billing quality data is required. The device meters kW and Kvar (bi-directional for Points of Interconnection) and records kWh and Kvarh data on an hourly basis. Data is retrieved over dial-up (voice grade) telephone lines by the MV-90™ system located at Dittmer Control Center. The MV-90™ system automatically polls the device every morning beginning at 0001 am. The MV-90™ system can also other times to poll a remote at.

Single Pole Switching: The practice of tripping and reclosing one phase of a three phase transmission line without tripping the remaining phases. Tripping is initiated by protective relays that respond selectively to the faulted phase. Circuit breakers used for single pole switching must be capable of independent phase opening. For faults involving more than one phase, all three phases are tripped. The purpose of single pole switching is to improve system stability by keeping two of the three transmission line phases energized and carrying power while the fault and secondary arc are removed from the faulted phase. See also 'hybrid single pole switching'.

Station Service: The electric supply for the ancillary equipment used to operate a generating station or substation. (NERC definition) Generally, main grid substations require two sources of station service for reliability.

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

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. The connection point may or may not include disconnect switches for isolation of one or all terminals.

Telemetering: Continuous, real time data reporting, as for AGC and generation kW (but not for kWh or RMS 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.

Transmission: That part of the electric grid associated with bulk transfer of energy, at high nominal voltages (generally defined as 115 kV or above). BPA owns and operates transmission facilities at voltages of 500, 345, 287, 230, 161, 138 and 115. of BPA's 345 kV- and 287-kV transmission is on lines that are transformer-terminated at both ends.

Transformers and Transformer Connections: Large three-phase power transformers can be constructed using separate windings, as autotransformers or a combination of these. Transformers can use one tank for each phase or have all three phases in a single tank. The external winding connections can be delta (Δ) or grounded wye (YG), creating winding combinations such as Δ - YG, YG - YG, YG - Δ – YG.

- Autotransformer: Transformer construction using a single coil where the lower voltage or 'winding' is created by simply tapping that coil at the desired voltage level, creating a metallic connection between the two windings. This is the typical construction used to transform voltages at transmission levels and uses a YG, three-phase connection (e.g. 525:230 kV, 230:115kV).

- Separate windings: Transformer construction where the higher and lower voltage windings are individual coils, only coupled by a magnetic field. This is the typical construction used to transform voltages from transmission to distribution levels and for generator step-up transformers (e.g. 115:12.5 kV, 22:230kV).
- Wye (Y) connection: Transformer connections where one end of each winding of the three phases is connected to a common point and then typically grounded (YG), possibly through an impedance.
- Delta (Δ) connection: Transformer connections where one end of each winding of the three phases is connected to the next phase, creating a closed loop of windings with no connections to a common point.

WECC: Western Electricity Coordinating Council, is the reliability region to which BPA's Balancing Authority Area (control area) belongs. WECC establishes and enforces reliability standards for operating and planning the bulk electric system in the region. On-line at www.wecc.biz

4. BACKGROUND

Copies of this document are available from:
BPA's Document Request Line at (800) 622-4520 and requesting DOE/BP– 3624
Or Web: http://www.transmission.bpa.gov/business/generation_interconnection/
If you have questions or need additional information, please call:
BPA's Public Information Center at (503) 230-7334 or (800) 622-4520

If you wish to make comments, please contact Transmission Planning or e-mail comments to **studyrequest@bpa.gov**.

Revision 0 of this document superseded DOE/BP-3183 Technical Requirements for the Connection of Transmission Lines and Loads and DOE/BP-3162 Technical Requirements for the Interconnection of Generation Resources.

5. REQUIRED INFORMATION FOR INTERCONNECTIONS

5.1 Introduction

Requests for generation interconnection to the BPA Grid are made via the Large Generation Interconnection Procedure (LGIP) for greater than 20 MW facilities, or by the Small Generation Interconnection Procedure (SGIP) for generating facilities no larger than 20 MW. Requests for non-generation interconnections are made through the Line and Load Interconnection Procedure (LLIP). Requests for energy storage should be made via the SGIP or LGIP depending on the nameplate peak power capacity. Requestors must contact a BPA Account Executive and refer to BPA Business Practices for application forms and procedures. This section describes typical information and data that BPA requires at various points in the life of the Interconnection Request.

5.2 Connection Location

BPA requires the Requester to submit location information with the interconnection request in order to adequately study the impacts. Location information required will vary depending upon the proposal.

- Locations of new substations, generators or new taps on existing lines must include the state, county, township, range, elevation, latitude and longitude.
- BPA requires driving directions to the location for a site evaluation.
- Identify the substation if connecting to an existing BPA substation.
- For connection to an existing BPA transmission line, identify the line by name as well as the location of the proposed interconnection.

5.3 Electrical Data

The specific electrical data required will depend upon the type of connection requested. BPA will provide supplemental data request forms when specific information is required that was not included with the application or other project submittals.

5.3.1 *Electrical One-Line Diagram*

The electrical one-line diagram should include equipment ratings, equipment connections, transformer configuration, generator configuration and grounding, bus, circuit breaker and disconnect switch arrangements, etc.

5.3.2 *Generator Data*

If one or more generators are included as part of the connection request, the following is typical data needed. If different types of generators are included, data for each different type of generator and generator step up transformer is needed.

5.3.2.1 <u>Typical Generator data:</u>

- Energy source (e.g., wind, natural gas, hydro, bio-mass, bio-gas, solar, geothermal, etc.)
- Number of rotating generators
- Number of turbines and type: wind, combustion, steam, hydro, engine generator, etc.
- Number and nameplate rating of static conversion devices (e.g. inverters for solar photovoltaic projects)
- Total nameplate rating in MW
- Nameplate power factor
- Station service load for plant auxiliaries, kW and Kvar
- Station service connection plan (specifically, which distribution utility will provide station service to the project when all generation is off line)

5.3.2.2 DC Sources

If the generator project includes dc sources such as fuel cells or photovoltaic devices, provide the number of dc sources and maximum dc power production per source in kW. Provide the nameplate output rating of each inverter in KW and power factor.

5.3.2.3 Variable Generation

The following data is generally required of each asynchronous variable Large Generation Plant consisting of multiple generation units connected via a network (collector) system proposed or in operation within BPA's Balancing Area. Similar data may be required for Small Generation consisting of multiple generation units and other asynchronous generation. The information is required to meet the WECC/NERC compliance requirements for Generation Owners / Generation Operators (GO/GOp).

- Proposed Wind Turbine Generator (WTG) or other variable generator manufacturer and data sheet(s), and main transformer(s) size and impedance.
- Collector system single line diagram that includes any proposed reactive equipment.
- Plant equivalent representation as defined by WECC.
- Submit post construction "as built" updates per WECC/NERC requirements to BPA following project commissioning. Include measured net reactive capability as measured at the POI.
- The owner must submit periodic updates of the Wind Generation Plant to BPA as required for WECC compliance with NERC Reliability Standards.

5.3.3 *Load Information Requirements*

If a new load or point of delivery is requested, the following information will generally be required.

- Type of load, such as industrial, commercial, residential or combination
- Load data
    - Delivery voltage, kV
    - Projected peak load, kW
    - Summer peak load, kW
    - Winter peak load, kW
    - Anticipated power factor

6. SYSTEM PLANNING & PERFORMANCE REQUIREMENTS

6.1 General Configurations

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

- Connection to an existing 69 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.
- Connection to an existing 69 kV to 500 kV transmission line via a tap
- Connection by looping an existing 69 kV to 500kV transmission line into a new customer or BPA owned substation.

These three categories may include the situation where another utility owns the transmission line or equipment that directly connects to the BPA Grid.

BPA must maintain full operational control of the transmission line. This may include, but not be limited to, SCADA control and monitoring of circuit breakers, disconnects and other equipment in the new substation. Additionally, BPA will retain contractual path capacity rights. New equipment installed in series with the existing transmission line shall have continuous thermal rating not less than the transmission line rating.

A multi-terminal line is created when the new connection becomes an additional source of real power and fault current beyond the existing sources at the line terminals. A line with three terminals affects BPA's ability to protect, operate, dispatch and maintain the transmission line. BPA determines the feasibility of multi-terminal line connections on a case-by-case basis.

If BPA allows a new customer-owned line to tap an existing BPA transmission line, the reliability of the BPA line is decreased due to short-term and long-term outages on the new line. BPA may require switching equipment at the tap point to provide automatic isolation of the new line if the expected decrease in BPA line reliability is substantial. Each situation is evaluated on a case-by-case basis.

6.2 Special Configurations

The following configurations may substantially affect the costs of a particular connection plan.

6.2.1 *Connection to Main Grid Transmission Lines and Substations*

Main Grid transmission lines include all 500 kV, 345 kV and some lower voltage lines, as defined by BPA's Reliability Criteria and Standards. These circuits form the backbone of the Pacific Northwest transmission system and provide the primary means of serving large geographical areas. In general, BPA requires a substation with additional breakers at the POI to maintain reliability and security of the main grid system. Breaker and a half configuration is typical. See the Breaker Arrangement Application Policy (STD-N-000003) for more on this topic.

6.2.2 *Connection to 287 kV and 345 kV Lines*

BPA can operate its 287 kV and 345 kV transmission lines at either the normal voltage or at 230 kV. Each of these lines is terminated with transformers that can be bypassed for 230 kV operation. BPA reserves the right to operate these lines at 230 kV. If the transformer fails at a terminal, extended 230 kV operation will be required. For continued operation the connected facilities must also be capable of operating at 230 kV.

6.3 Generators (General Requirements)

6.3.1 *Generator Operation During Emergency System Conditions*

The generator, when requested by the BPA Dispatcher during emergency conditions, will be expected to supply reactive power up to its maximum available capability, even if reductions to generation levels are required. Dispatch for non-synchronous sources will be examined on a case-by-case basis, depending upon the performance characteristics of the source and its location within the BPA grid.

6.3.2 *Generator Performance During System Disturbances (Swings)*

Response to frequency and voltage variances during a system disturbance are defined in Section 10. Unless otherwise allowed, the generators are to stay connected and operational during such disturbances, up to the limits provided in Section 10. Deviation from these requirements will be reviewed on a case-by-case basis and may result in additional reserve requirements or other system compensation.

6.3.3 *Generator Low Voltage Ride Through Capability*

All large generator (greater than 20 MW) installations shall meet NERC and WECC requirements for low voltage ride through (LVRT). The generator(s) shall be capable of staying on-line for nearby faults, except for faults on the line or bus the generator is connected to. This includes traditional thermal, hydro, wind, solar PV, and solar thermal greater than 20 MW. Small generation installations (less than or equal to 20 MW) LVRT will be as determined by BPA studies.

In addition to the NERC and WECC LVRT requirements, all generators must meet the BPA under/over voltage and under/over frequency requirements for operation in the BPA system listed in this document, unless BPA Planning has determined otherwise. Section 10.1.4.3.1 prescribes the voltage with time delays requirements for generators. Frequency requirements are listed in Table 4 in section 10.1.4.3.2.

6.3.4 *Reactive Power Requirements*

All large generator installations are required to provide reactive power for voltage support of the transmission system. Both Primary and Secondary reactive power may be required. From the standpoint of voltage stability, it is necessary to distinguish between Primary and Secondary voltage control.

Primary voltage control acts upon fast-acting continuously controllable (dynamic) reactive power devices to provide automatic voltage response to system voltage changes, including generation output changes, grid disturbances to stabilize the power system; and to smooth shunt reactive switching steps. Continuously controllable, fast-acting reactive power devices include synchronous generator excitation systems, generators with electronically controlled output and electronically controlled reactive power devices. The Primary response typical time frame is from several cycles (after fault interruption) to a second, similar to synchronous generators with modern excitation systems.

Secondary voltage control is slower acting to maintain a voltage schedule during normal system operation, to aid system recovery after a disturbance, and to maximize the availability of the generator installation's fast acting, continuously controllable reactive power devices for Primary voltage control. The Secondary response typical time frame is several seconds to a minute. Secondary reactive power is often provided by mechanically-switched shunt capacitors and reactors. Secondary voltage control is usually implemented in a programmable logic controller as part of the generation installation's control system.

All large generator installations shall be designed to provide dynamic reactive power at rated power output at the Point of Interconnection. The requirement is over the range of 0.95 leading to 0.95 lagging power factor (FERC requirement for synchronous generation) or as determined by BPA studies.

BPA studies may allow the Large generator installation to provide the Primary reactive power as a combination of low side bus fast-acting, continuously controllable reactive power capability (e.g. synchronous generators, generators with electronically controlled output or static var devices) and switched reactive equipment connected to the low side bus or at the POI. Switched reactive power equipment shall be sized to compensate for reactive power losses and injection between the generator installation and the POI and to meet the total reactive power requirement at the POI as determined by BPA studies. The compensation shall consider the effects of low voltage generator (collector) system reactive losses, step-up transformer reactance, transmission line reactive losses, voltage taps/turns ratios, and bus-fed auxiliary load. The compensation shall also consider the effects of reactive power injection due to low voltage generator (collector) systems and transmission lines at low generation levels when connected to the BPA system.

Additional reactive capability may be required, as determined by BPA technical studies. Large generation will be required to provide data on reactive capability. See section 13 for Dispatch and Data Requirements and Table 7.

6.3.5 *Asynchronous Generators*

Asynchronous generation includes wind, solar and other generation resources that rely on induction generators or inverters to provide power to the transmission system.

6.3.5.1 Asynchronous Squirrel Cage Induction Generators (Type 1) or Wound Rotor Induction Generators (Type 2)

Large asynchronous generators with only switched capacitors for PF correction shall provide reactive power compensation via supplementary external equipment as specified in the BPA system planning studies. For Type 1 and 2 wind generators, the dynamic reactive power is supplied by a separate fast-acting, continuously controllable reactive power device (STATCOM typically) providing compensation in response to the power plant voltage controller, while the individual generators operate in constant power factor mode. The dynamic reactive power device is typically connected to the power plant collector bus.

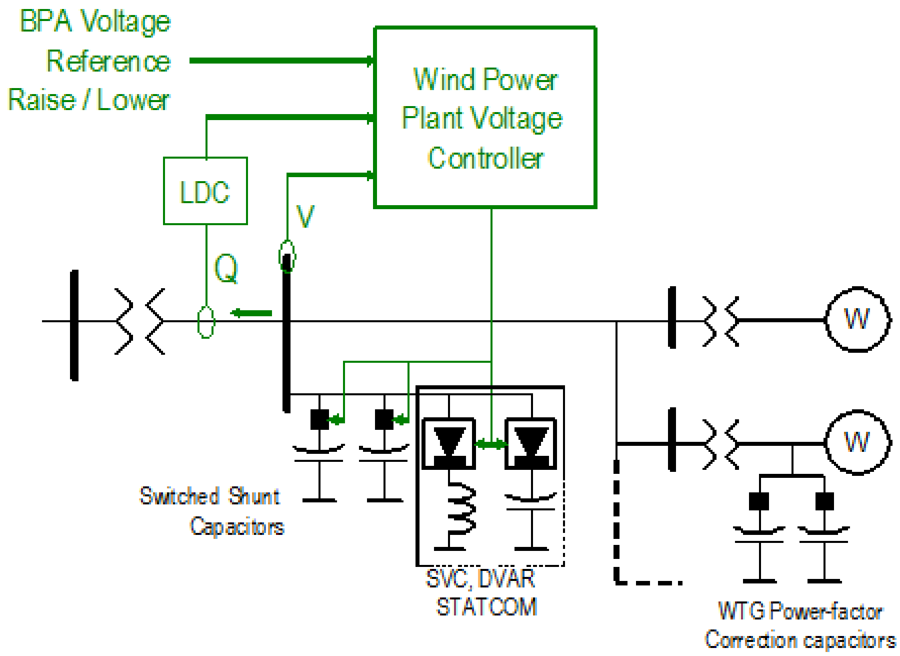

Figure 1.--- Example of Type1, 2 Wind Turbine Reactive Power Control with Fast Acting, Continuously Controllable Plant-level Reactive Compensation (SVC, STATCOM, DVAR, etc). Switched Shunts are Used to Meet the BPA Reactive Requirements at the POI

Additional switched reactive power devices required to meet the total reactive power requirement at the POI shall be controlled by the power plant voltage controller. The voltage controller is to switch shunt devices to optimize available dynamic reactive reserves at the POI. The required dynamic reactive power device supports the transmission system during disturbances and can be used to smooth shunt reactive switching steps.

6.3.5.2 Asynchronous Double-fed Wound Rotor Induction Generators (Type 3) and Generators with Solid-State Inverters (Type 4)

For Type 3 and 4 wind generation (may include solid state Inverter type generation such as solar PV), the continuous dynamic response reactive power is provided by each generator or the solid state equipment at each generator per BPA system planning studies. The generation facility has a voltage controller that dispatches reactive power output from each generating unit (Type 3 or 4) and controls switched shunt reactive devices.

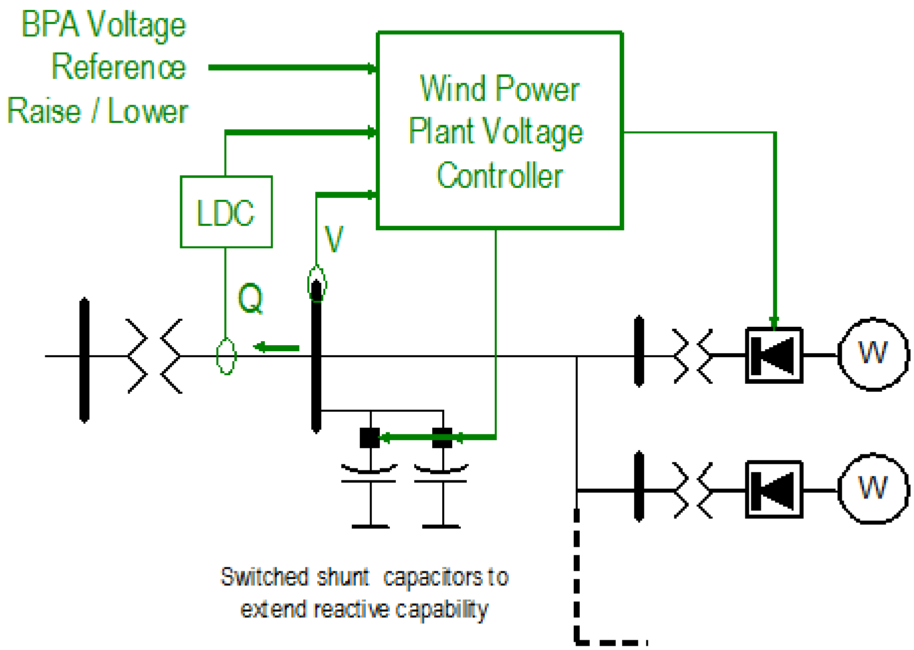

Figure 2.--- Example of Type 3, 4 Wind Turbines Providing Primary Generator Reactive Power. Voltage Controller Switches Shunt Devices to Maximize Available Dynamic Reactive Reserves at the POI. Switched Shunts are Used to Meet the BPA Reactive Requirements at the POI

(Note: The generators must be capable of reactive power output for the BPA system in response to the plant voltage controller demands, i.e. there are no patent or other issues preventing such control to qualify as the dynamic reactive source).

The generation facility provides the Primary reactive power to maintain voltage of the transmission system and can be used to smooth shunt reactive switching steps.

Additional switched reactive power required to meet the total reactive power requirement at the POI shall be controlled by the power plant voltage controller. The voltage controller is to switch shunt devices to optimize available dynamic reactive reserves at the POI.

When the need is identified by BPA studies or from operational experience, the project will be required to provide dynamic controllable reactive compensation such as static VAR compensators (SVC).

6.3.5.3 Mitigating Voltage Impacts to the Transmission System

This issue is applicable to all types of power generators, but particularly acute for variable generation resources. If a power plant is connected to a weak transmission system, the power output fluctuations may cause excessive voltage change for transmission customers in the area due to fluctuations in transmission line power flows.

Figure 3 illustrates the issue. The voltage change at V2 may cause excessive operation of customer load tap changers and voltage regulators. The generator voltage control system shall be coordinated to minimize operation of customer load regulation equipment including voltage regulators and tap changers. This may typically require the control system to adjust reactive compensation in less than 20 seconds and the reactive step size such that switching action does not cause voltage change outside regulator's voltage band.

Perceptible flicker may also result from the change in voltage at the terminal of the generation project for changes in generation output and / or as the power output changes the line loading voltage. As the power plant output fluctuates, so does the customer POI voltage, even if the voltage at plant POI is held constant.

When the need is identified by BPA studies or from operational experience, the project will be required to provide dynamic controllable reactive compensation such as static VAR compensators (SVC).

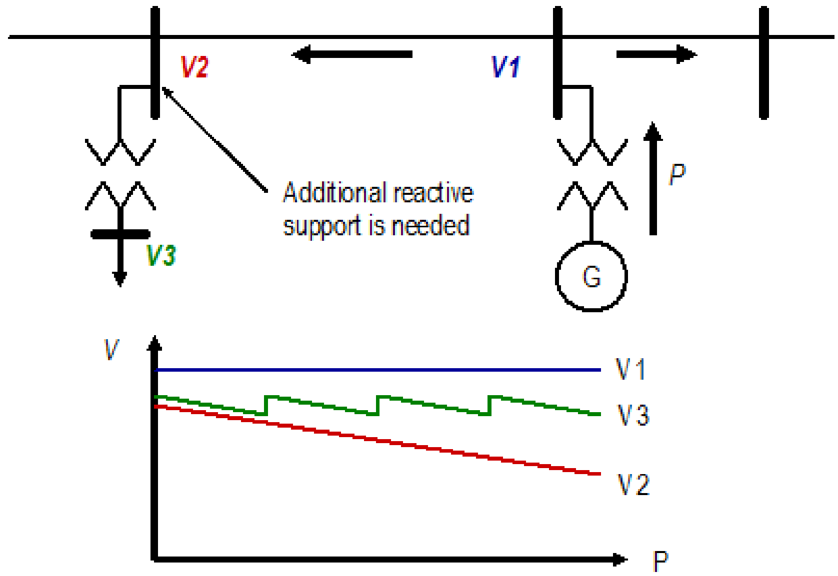

Figure 3.--- Voltage Impact On Line Connected Load For Variable Generation

6.3.5.4 Other Asynchronous Generation

Large generation (>20 MW aggregate nameplate including solar PV and solar thermal) from other resources shall be required to provide reactive power compensation as specified in the BPA system planning studies. The reactive power will either be supplied by the solid-state inverter used for energy conversion or from a separate fast-acting, continuously controllable reactive power device (STATCOM typically) providing compensation in response to a voltage controller. The separate reactive power device is typically connected to the power plant collector bus. The required Primary reactive power device supports the transmission system during disturbances and can be used to smooth shunt reactive switching steps.

For applications where continuous dynamic reactive power is not required, voltages at the POI shall not vary more than 0.5% per capacitor switching operation during normal transmission system conditions; and shall not deviate more than 1% due to changes in generation output caused by rapid fluctuations in the prime mover output.

6.3.6 *Synchronous Generators*

6.3.6.1 Voltage Control

Automatic Voltage Regulation (AVR) is required for an individual generator with nameplate rating 20 MVA or above, and on each generator regardless of size in a group installation where the aggregate nameplate rating is 75 MVA or above.

Power System Stabilization (PSS) is required on each individual generator with nameplate rating 20 MVA or above.

Regardless of whether the GO/GOp registers, if the above criteria apply, BPA will require that the generation facility is equipped and operated in a manner that supports BPA's compliance with mandatory reliability standards. Therefore, the requirement for AVR and PSS will apply at the same MVA ratings listed above if the individual generating unit or generating plant/facility is covered by the NERC Statement of Compliance Registry Criteria.

The interconnection customer shall equip each generator with Automatic Voltage Regulation (AVR). Interconnection customer shall operate AVR in voltage control mode at all times when the generator is synchronized to the transmission system.

The interconnection customer shall include a Power System Stabilizer (PSS) feature in the generator AVR. The PSS shall be dual input integral of accelerating power type (IEEE type PSS2A). Minimum PSS performance requirements shall be as described in the Western Electric Coordinating Council's "WECC PSS Design and Performance Criteria". Interconnection customer shall maintain the PSS in service at all times when the generator is synchronized to the transmission system.

All large generators shall operate on voltage control or as determined by BPA studies. Power factor control is not allowed except as determined by BPA. The power plant voltage controller must coordinate the mechanically switched shunts and dynamic reactive resources to optimize the Primary (dynamic) response for support of the transmission system during disturbances. The voltage controller shall coordinate the mechanically switched shunts and dynamic reactive resources to provide smooth shunt reactive switching steps. The preferred voltage control point for Primary voltage control is the power plant generator bus (or collector bus for wind and other multi-generator systems) with line drop compensation looking approximately two-thirds forward through the substation step-up transformer impedance. The power plant voltage controller shall be capable of receiving BPA voltage reference raise and lower signals. When the voltage at the control point is above the scheduled voltage, the plant is expected to consume reactive power (inductive operation). When the voltage at the control point is below the scheduled voltage, the plant is expected to supply reactive power (capacitive operation).

For applications where no dynamic devices are required, the automatic voltage control system shall be sufficiently fast to react to the maximum change in generation anticipated without invoking the operation of system voltage control devices such as shunt capacitors and tap changers. Further, the control system shall be coordinated to minimize operation of customer load regulation equipment including voltage regulators and tap changers. This typically requires the control system to adjust switched reactive compensation in less than 20 seconds. For switched reactive equipment supporting generation reactive power requirements, voltages at the POI shall not vary more than 0.5% per switching operation; and POI voltage shall not deviate more than 1% due to changes in generation output caused by rapid fluctuations in the prime mover speed. When the need is identified by BPA studies, the requester will be required to provide dynamic controllable compensation such as static VAR compensators (SVC).

6.3.6.2 Excitation Equipment

Synchronous generator excitation equipment shall follow industry best practice and applicable industry standards. The excitation equipment includes the exciter, automatic voltage regulator, power system stabilizer and over-excitation limiter. Supplementary controls are required to meet BPA transmission voltage schedules.

All synchronous generators shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator. The intent and BPA requirement is that continuous automatic voltage control not be overridden by supplementary power factor or reactive power controls that are either part of the automatic voltage regulator or the power plant distributed control system.

Generators shall maintain a network voltage or reactive power output as required by BPA within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with the electric system voltage requirements.

Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short duration capabilities and protective relays.

The synchronous generator exciter is normally of the brushless rotating type or the static thyristor type. The excitation system nominal response shall be 2.0 or higher (for definitions see IEEE Standard 421). The excitation system nominal response defines combined response time and ceiling voltage. In some cases, the high initial response static type may be required to economically improve power system dynamic performance and transfer capability.

Automatic voltage regulators (AVRs) should be of continuously acting solid-state analog or digital design. Generator voltage regulators to the extent practical should be tuned for fast response to step changes in terminal voltage or voltage reference. It is preferable to run the step change in voltage tests with the generator not connected to the system so as to eliminate the system effects on the generator voltage. Terminal voltage overshoot should generally not exceed 10% for an open circuit step change in voltage test. Tuning results should be included in commissioning test reports provided to BPA.

WECC requires that generating unit voltage regulators on generating units where rated output exceeds certain thresholds, individually or in aggregate, be equipped with a power system stabilizer (PSS). The PSS should be tuned in accordance with WECC guidelines and other industry practices. The 'integral of accelerating power' type of PSS is preferred. Its input can be a speed-related signal derived from terminal voltage and current measurements used in the basic AVR. The PSS can be implemented as a software module within the AVR. BPA recommends that the PSS be included in the procurement specifications as an integral part of the voltage regulator and that AVR and PSS tuning and commissioning be performed.

The voltage regulator shall include an over-excitation limiter. The over-excitation limiter shall be of the 'inverse-time' type, adjusted to coordinate with the generator field circuit time-overcurrent capability. Automatic voltage regulation shall be restored automatically when system conditions allow field current below the continuous rating. BPA may request connection of the voltage regulator line drop compensation circuit to regulate a virtual location 50–80% through the step-up transformer reactance.

The supplementary automatic control is required to adjust the AVR set point to meet the BPA network side voltage schedule. This supplementary control should operate in a 10–30 second time frame, and may also balance reactive power output of the power plant generators.

6.3.6.3 Governors

To comply with NERC BAL-003-1 Reliability Standard (effective Dec 1st, 2016), BPA may need to acquire frequency response from generators within its Balancing Authority. BPA, therefore, requires that all generators have capabilities to provide frequency response, specifically:

- Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency
- Prime mover control (governors) should operate freely to regulate frequency. Governor droop should generally be set at 5% and total governor dead band (intentional plus unintentional) should generally not exceed ±0.06%. These characteristics should in most cases ensure a coordinated and balanced response to grid frequency disturbances. Prime movers operated with valves or gates wide open should control for overspeed/overfrequency.
- Plant load controllers, when used, must have a frequency bias setting, ensuring that plant controls do not restrict frequency response.

BPA realizes that some generating facilities will operate at maximum turbine output unless providing frequency control and spinning reserve ancillary services. BPA requires governor controls to be set for 'droop control mode'.

6.3.7 *Generator Performance Testing, Monitoring and Validation*

Each generator owner is responsible to provide a dynamic model of its generating plant to BPA. The model will characterize plant responses to system disturbances (voltage and frequency deviations at point of interconnection, oscillations) and control signals (power and voltage schedule). The dynamic model will be a part of the power system model used in system studies to determine operating transfer limits and network reinforcements. An incorrect model may result in incorrect transfer limits, which can either put the system at risk of failure or unnecessarily restrict transmission use.

6.3.7.1 Parametric Testing

Parametric testing is a detailed test performed on a generator to determine parameters of a synchronous machine and its controls, as defined in the WECC test guidelines. Parametric testing shall be done for the following equipment:

- Synchronous machines
- Exciter and Automatic Voltage Regulator (AVR)
- Turbine – governor
- Power System Stabilizer (PSS)
- Over-Excitation Limiter (OEL)

Typical data cannot be substituted for actual parametric test data when required by NERC or WECC standards. Testing is required:

- On a new generator during commissioning.
- When the generator or turbine is retrofitted.
- When the generator controls are replaced or retuned.

When a severe discrepancy is observed in performance validation.

6.3.7.2 Performance Validation

Performance validation of the generator model is done using measurements recorded during actual disturbances and tests. Recorded generator voltage and frequency are input into the model to verify that simulated real and reactive power responses are in good agreement with the recorded responses. Generator owners shall submit an Evidence of Performance Validation every five years. Performance validation shall include:

- Responses to at least three frequency excursions greater than 0.1 Hz (alternatively 1% speed or 20% power reference steps);
- Responses to at least three voltage changes greater than 2% (alternatively 2% voltage reference steps).

6.3.7.3 Performance Monitoring

BPA will monitor performance of a generating plant as described in Section 7.5

6.3.8 *Blackstart Capability*

Blackstart is the term describing the startup of a generating plant under local power, isolated from the power system. Blackstart capability is needed in some rare circumstances, depending on the size and location of the generation facility. It is generally not needed for small generators or for projects that are near other major generation. This capability is addressed in the planning and review process, and indicated on the Project Requirements Diagram. Loads that are scheduled and available for blackstart are selected to avoid tripping generation units by exceeding frequency and voltage set points. Selecting voltage variable loads, avoiding motor start-up loads, and imposing block size limits of (50 MW or less) can accomplish this. During blackstart restoration, the tapped connection must be able to be opened to avoid interference with BPA restoration procedures on the BPA transmission path.

Considerations related to blackstart capability include the following:

- Proximity to other major generation facilities (i.e. Can startup power be provided more efficiently from an existing plant?)
- Location on the transmission system (i.e. Is the generation facility near major load centers and far from generation?)
- Cost of on-site start-up
- Periodic testing to ensure personnel training and capability

6.4 System Stability and Reliability

The BPA Grid has been developed with careful consideration for system stability and reliability during disturbances. The type of connection, size of the source or load, breaker configurations, source or load characteristics, and the ability to set protective relays will affect where and how the connection is made. For most generators and some loads, the Requester will also be required to participate in special protection or Remedial Action Schemes (RAS) including automatic tripping of generation or load. Section 10.1.5 provides additional information and requirements for RAS schemes.

6.4.1 *Key Reliability and Availability Considerations*

- The new connection shall meet all applicable NWPP, NERC and WECC operating and reliability criteria requirements. When in conflict, the more restrictive requirement shall apply.
- Tools and spare equipment must be readily available to accomplish operations and maintenance tasks.
- Bypass equipment must be fully rated to allow continued operation without creating a bottleneck. Alternate feeds, when provided, shall have sufficient rating to not restrict operation of the BPA Grid.

- Shielding and electromagnetic interference (EMI) protection shall be provided to insure personnel safety and proper equipment functioning during disturbances such as faults and transients.
- Standardized design, planning, operating practices and procedures should be used so the new connection may be readily incorporated into the existing transmission network.
- For reliable operation, the telecommunications, control and protection equipment must be redundant to the extent described in Sections 10 and 11.
- The equipment for the new connection shall have sufficient capabilities for both the initial operation and for long-range plans.
- Operations and maintenance personnel must be properly trained for both normal and emergency conditions

6.4.2 *Atmospheric and Seismic*

The effects of windstorms, 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 to determine that the appropriate standards, codes, criteria, recommended practices, guides and prudent utility practices are met for equipment it furnishes and installs.

6.4.3 *Physical Security*

The potential vulnerability of the facility to sabotage or terrorist threat must be factored into the design and operating procedures. The Requester is responsible to determine that the appropriate standards, codes, criteria, recommended practices, guides and prudent utility practices are met for its installation.

6.4.4 *Transmission and Substation Facilities*

Some new connections to the BPA Grid require that one or more BPA 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 shall not restrict the capability of the line(s) and BPA's contractual transmission path rights. Customer owned transmission lines that interconnect with BPA facilities shall meet the requirements specified herein at the POI and where specified to maintain worker safety and electrical protective margins.

6.4.5 *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 be added to control voltage stress to acceptable levels. Interconnection studies include the evaluation of the impact on equipment insulation coordination. BPA may identify additional requirements to maintain an acceptable level of BPA Grid 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 station shielding against direct lightning strokes, surge arresters on all line terminals, transformers, reactors, and station entrance shielding with OHGW.

6.4.6 *Temporary Overvoltages*

Temporary overvoltages can last from seconds to minutes, and are not characterized as surges. Although BPA follows NESC operating procedures such that voltage control practices do not normally cause temporary overvoltage, temporary overvoltages may be present during islanding, faults, loss of load, or long-line situations. All new and existing equipment must be capable of withstanding temporary overvoltage.

6.4.7 *Ancillary Services*

All new connections to the BPA Grid require an interconnection agreement. The interconnection agreement does not imply or guarantee transmission service or ancillary services.

All loads and transmission facilities must be part of a balancing authority area. The balancing authority area provides critical ancillary services, including load regulation, and frequency response, operating reserves, voltage control from generating resources, scheduling, system controls and dispatching service, as defined by FERC, or their successors. A transmission contract is optional. The Requester must choose the balancing authority area in which the new facilities will be located and the source or provider of ancillary services. This election should be identified 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. BPA will then determine the telemetering, controls, and metering that will be required to integrate the load or facility into the chosen balancing authority 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 BPA automatic generation control, (AGC) system. The provision of the required ancillary services must meet all relevant NERC, WECC and NWPP reliability policies and criteria.

The generator is required to operate in automatic voltage control mode, regulating the voltage to a BPA provided schedule. Typically the generator should supply reactive power for its station service loads and reactive power losses up to the POI. Generator projects may be requested to supply reactive power as an ancillary service.

Normally, the generator will operate its governor to respond independently for frequency deviations. If the governor is controlled through the plant central controller, the governor shall be in ‘droop control’ mode. Droop setting and performance shall comply with applicable NERC and WECC reliability standards and guidelines.

6.4.8 *Power Quality*

Power quality is the responsibility of both the end users (loads and generation) connected to a utility system and the utilities providing distribution and transmission. Since this document focuses on the interconnection of loads and generation to the BPA Grid, this section will deal primarily with power quality problems typically introduced by the end user or Requester as termed in this document. The Requester is expected to address, in the design of their facilities, potential sources and mitigation of power quality degradation prior to interconnection. Design considerations should include applicable standards including, but not limited to IEEE Standards 142, 519, 1100 1159, 1547, and ANSI C84.1.

In general, the Requester has the responsibility not to degrade the voltage of the utility (BPA) serving other users by requiring nonlinear currents from the system. The Requester also has certain responsibilities to account for transmission system events such as switching transients and fault-induced voltage sags. Standards exist for manufacturers and system designers to take into account short duration system events in order to design equipment or systems with sensitivities capable of riding through events that are within utility system operating standards. If it is determined that the new connection facility is causing a power quality problem, then the Requester will be held responsible for installation of the necessary equipment or operational measures to mitigate the problem. Typical forms of power quality degradation include, but are not limited to voltage regulation/unbalance, harmonic distortion, flicker, voltage sags/interruptions, and transients. Some of the more common forms of degradation are discussed below.

6.4.8.1 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 and IEC 61000-3 provides definitions and limits on acceptable levels of voltage fluctuation. Loads or system connections to the BPA Grid shall comply with the limits in these standards.

6.4.8.2 Harmonic Distortion

Nonlinear devices such as adjustable or variable speed drives (ASD/VSD), power converters, arc furnaces, and saturated transformers can generate harmonic voltages and currents on the transmission system. These harmonics can cause telecommunication interference, increase thermal heating in transformers and reactors, disable or cause misoperations of solid-state equipment and create resonant overvoltages. In order to protect power system equipment from damage or misoperations, harmonics must be managed and mitigated. The new connection shall not introduce harmonics into the BPA Grid in excess of the limits specified in IEEE Standard 519.

In addition to loads with nonlinear devices, new generation resources or distributed resources should be evaluated not only for possible injected harmonics, but also for potential resonant conditions. For example, some generation resources, whether due to power factor correction capacitors or cable capacitances, may be capacitive during certain operating configurations. These types of configurations may result in resonant conditions within the project or in combination with the utility system. The short circuit ratio (SCR) tests as listed in IEEE 1547 and IEEE 519 can be good indicators of this potential problem. If the evaluation of the new connection indicates potential harmonic resonance the requester may be required to filter, detune, or mitigate in some way the potential resonant conditions associated with connection of the new resource.

For individual end users, the IEEE 519 Standard limits the level of harmonic currents injected at the POI (listed in IEEE literature as the Point of Common Coupling (PCC)) between the end user and the utility. Recommended limits are provided for individual harmonic components and for the total demand distortion. These limits are expressed as a percentage of the customer's demand current level, rather than as a percentage of the fundamental, in order to provide a basis for evaluation over time. There are also limits for voltage distortion for both individual frequency and total harmonic distortion.

6.4.8.3 Phase Unbalance

Unbalanced phase voltages and currents can affect coordination of protective relaying, create higher flows of current in neutral conductors, and cause thermal overloading of transformers and motors. The measurement of voltage unbalance, Negative Sequence Unbalance Factor (NSUF) is the ratio of the negative sequence voltage divided by the positive sequence voltage, expressed as a percentage. The NSUF limits listed herein applies to normal system operations. For connections at 230 kV and above, the voltage unbalance should not exceed 1%. For connections below 230 kV, the contribution at the POI from a single interconnection should not be allowed to cause a voltage unbalance greater than 1.3%. The voltage unbalance limit is 2% at Points of Common Coupling for the aggregate effect of multiple loads.

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 all of its connected equipment from damage that could result from such an unbalanced condition.

7. GENERAL DESIGN CONSIDERATIONS

7.1 Minimizing 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
- Other disturbances that might degrade the reliability of the interconnected BPA Grid

7.2 Existing Equipment

The proposed new connection may cause existing equipment such as transformers, power circuit breakers, disconnect switches, arresters, and transmission lines to exceed their ratings. New connections may require equipment replacement or an alternate plan of service.

7.3 Safety and Isolating Devices

A disconnect switch is required at any interconnection to the BPA Grid to provide physical and visible isolation of the BPA Grid from the connected facilities. The isolation device may be placed in a location other than the Point of Interconnection (POI), by agreement of BPA and affected parties. Safety and operating procedures for the isolating device shall be in compliance with the BPA Accident Prevention Manual (APM) and the Requester's and interconnecting utility'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. Isolating devices on lines or in substations that may be used for electrical clearance boundaries or maintenance purposes shall meet the "visible air gap" requirement in the BPA APM. The following requirements apply for all isolating devices:

- Must simultaneously open all three phases (gang operated) to the connected facilities.
- Must be accessible by BPA.
- Must be lockable in the open position by BPA.
- Will not be operated without advance notice to affected parties, unless an emergency condition requires that the device be opened to isolate the connected facilities.
- Must be suitable for safe operation under all foreseeable operating conditions.

All work practices involving BPA owned, maintained, and/or operated equipment, must be done in accordance with the principles contained in the BPA Accident Prevention Manual, the BPA Work Standards, and done at the direction of BPA Dispatchers. BPA personnel may lock the isolating device in the open position and install safety grounds:

- For the protection of maintenance personnel when working on de-energized circuits.
- If the connected facilities or BPA equipment presents a hazardous condition.
- If the connected facilities jeopardize the operation of the BPA Grid.

7.4 Configuration for Sectionalizing and Maintenance

The configuration of interconnected facilities shall provide sufficient flexibility to allow taking each transmission line or line section, and each circuit breaker and other key equipment out of service, for both operation and maintenance purposes.

7.5 Synchro-phasers (Phasor Measuring Units)

BPA monitors the response to system events by generation projects connected to the BPA grid by measuring bus voltage and frequency, and generation current and power. Performance monitoring is required to fully validate performance and verify the model provided under Section 6.3. BPA will collect disturbance data and will perform performance validation. If BPA observes a severe discrepancy between Requester-provided data and monitored results, the generation project owner shall be required to perform parametric testing of the generation equipment.

BPA uses a Phasor Measuring Unit (PMU) to monitor generator performance. A PMU provides digital high-speed time-synchronized voltage and current phasors and frequency measurements. BPA requires PMU functionality at all generation projects that are directly connected to the BPA grid at voltages 230-kV and above, and at some lower voltage interconnections when identified during the interconnection studies. The PMU will be installed at the project substation (typically a collector station if a wind generation project) and will measure quantities at either the low side or high side of each substation step-up transformer (e.g. 34.5/230 kV).

BPA will install the PMU and the required communication circuits/equipment at the project substation to transport the information to the Control Center. After a system event, BPA will download data from the PMU. Depending on the Point of Interconnection to the BPA grid, and as identified during the interconnection studies, BPA may also require a continuous data stream to a BPA Phasor Data Concentrator (PDC) located at the BPA Point of Interconnection via the installed communications network at the project substation. The PMU must be tested after configuration (but prior to installation) for compliance with IEEE C37.118 standard and WECC filtering and dynamic performance requirements. A typical PMU installation is shown in Figure 4 below.

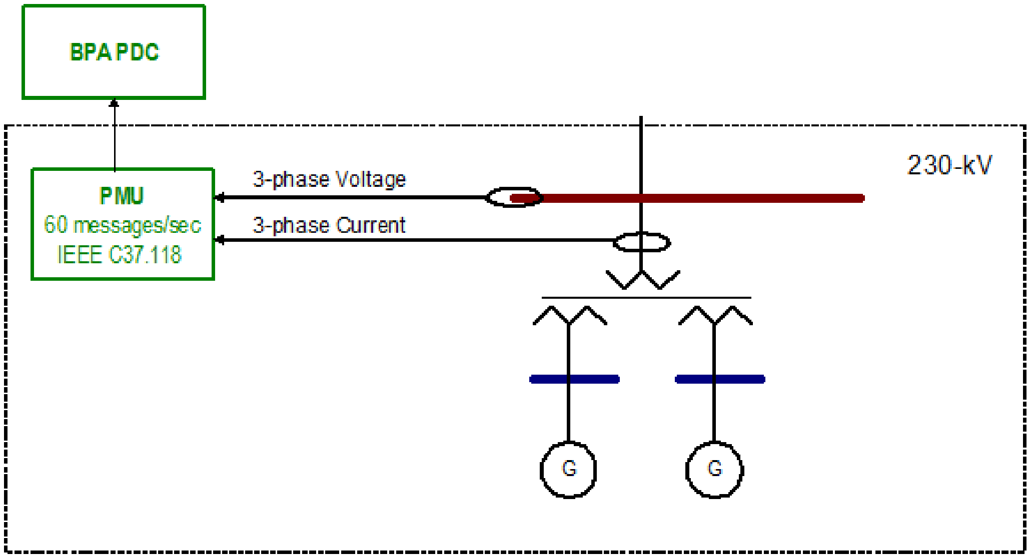

Figure 4.--- Typical Phasor Measurement Unit (PMU) Installation

7.6 STATCOM Type Controllable Reactive Power Devices

Dynamic reactive devices such as a STATCOM typically have an overload capability of 200% or more for 2 seconds. BPA studies have found that this overload capability can be used to reduce the size of the continuous rating in combination with switched capacitors. STATCOM devices inherently include capacitor control as part of the total reactive power system. As allowed by BPA studies, the total reactive power dynamic requirement can be provided as a combination of 50% fast-acting continuous STATCOM rating (with a minimum of 200% overload capability for 2 seconds) and 50% switched shunt capacitors to provide the continuous reactive power requirement.

Voltage control shall include line droop to provide fast response for major system events while desensitizing for small changes in voltage. Intentional deadband or additional time delays in the voltage control are not permitted without concurrence by BPA.

All additional switched reactive power required to meet the total reactive power requirement at the POI shall be controlled by the STATCOM voltage controller. The controller will be the interface for BPA dispatch of Primary and Secondary reactive power control functions.

7.7 Higher Speed Switching of Low Voltage Shunt Capacitors

Shunt Capacitors are used to provide reactive support for asynchronous generation facilities. They typically have a re-insertion delay (close-open-close) to allow for discharge of trapped charges. The time to discharge can be several minutes. Magnetic (wire-wound) potential transformers added to each capacitor section on the high voltage terminals can reduce the time to reinsert to only a few seconds. Planning studies will specify when this is a requirement for the power plant for system reliability. This may be especially useful for sub-grid applications that do not require dynamic equipment.

8. SUBSTATION FACILITY / HIGH VOLTAGE EQUIPMENT DESIGN

8.1 BPA Substation Requirements

BPA owned or maintained substations or equipment installations within foreign substations shall be designed to meet all applicable reliability criteria and applicable BPA Design Standards, and shall meet the requirements of the BPA Accident Prevention Manual. Among these requirements are the following:

- The requirements of the NESC C2 and OSHA shall be met.
- Substations shall be designed to meet BPA's minimum approach distances as specified in the APM and "Preferred" spacing for phase to phase and phase to ground distances consistent with BPA Substation Design Standards.
- Substation line terminals shall include OHGW as defined in Section 6.
- All substation layouts and expansions will provide adequate space and distance to property lines to meet BPA requirements for noise control per BPA Noise Policy.
- Substations shall include direct stroke lightning shielding consistent with BPA Substation Design Standards.
- All substation line terminals shall incorporate surge protection on the line side with metal oxide varistors (MOV) and will be coordinated with the existing substation and equipment insulation levels. This includes all lines or cables below 69kV (those not required to have OHGW) entering a BPA substation and connecting directly to BPA substation equipment such as station service transformers or BPA owned switchgear.

8.2 Customer Built Substations and Facilities

When BPA allows a customer-built substation to interrupt an existing BPA transmission line, the facility shall be designed to meet all transmission line capacity ratings and BPA reliability criteria.

8.3 Switchgear

8.3.1 *General Requirements*

Circuit breakers, disconnect switches, and similar equipment connected to BPA's transmission facilities shall be capable of carrying both normal and emergency rating load currents, and must also withstand available fault currents without damage. This equipment shall not become a limiting factor, or bottleneck, in the ability to transfer power on the BPA Grid. During prolonged steady-state operation, all such equipment shall be capable of carrying the maximum continuous current that the interconnected facility can reasonably deliver.

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. Application shall be in accordance with ANSI/IEEE C37 Standards. These requirements apply to the equipment at the POI as well as other locations on the BPA Grid. BPA supplies the fault-interrupting requirements.

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 Δ-YG transformer, the high-voltage side may become ungrounded when remote end breakers open, resulting in high phase-to-ground voltages. This neutral shift phenomenon is described in Section 8.4.3. Switchgear on the high side of a Δ-YG transformer that interrupt faults or load must be capable of withstanding increased recovery voltages.

Circuit breakers shall be capable of performing other duties as required for specific applications. These duties may include capacitive or inductive current switching, and out-of-step switching. Circuit breakers shall perform all required duties without creating transient overvoltages that could damage BPA equipment.

Generally, circuit breakers for transmission lines are required to provide automatic high-speed reclosing, with reclose times ranging from 1/3 of a second to two seconds (20 to 120 cycles). Circuit breakers for 500 kV lines will also typically be required to perform single-pole switching. 500 kV breakers without resistors on transmission lines will use staggered three-pole closing, in which each phase is closed about one cycle (16 ms) apart.

8.3.2 *Circuit Breaker Operating Times*

Table 1 specifies the interrupting times typically required of circuit breakers on the BPA Grid. These times will generally apply to equipment at or near the POI. System stability considerations may require faster opening times than those listed. Breaker close times are typically three to eight cycles. Circuit breaker interrupting time may vary from those in Table 1 but must coordinate with other circuit breakers and protective devices.

Table 1.— Typical Circuit Breaker Interrupting Times

Voltage Class (kV L-L rms)	Rate Interrupting Time (Cycles)
Below 100 Kv	≤ 8
100 kV to 138 kV	≤ 5
161 kV to 230 kV	≤ 3
287 kV to 345 kV	≤ 2
500 kV	≤ 2

8.3.3 *Other Fault-Interrupting Devices*

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 delta side of a Δ-YG 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.

8.3.4 *Transformers, Shunt Reactance and Phase Shifters*

Transformer tap settings (including those available for under load and no load tap changers), reactive control set points of shunt reactive equipment, and phase shift angles for phase shifters must be coordinated with BPA 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.

Transformer reactance and tap settings for generator transformers should also be coordinated with BPA to optimize the reactive power capability (lagging and leading) that can be provided to the network. Refer to IEEE Standard, C57.116, Guide for Transformers Directly Connected to Generators. The continuous reactive-power capability of the generator shall not be restricted by main or auxiliary equipment, control and protection, or operating procedures.

8.4 Transformer Considerations

8.4.1 *New Installations*

The BPA transmission system typically uses autotransformers to change transmission-level voltages (e.g. 500-230 kV, 230-115 kV), where the voltages on each side are in phase. Some 69 kV and most lower-voltage circuits (34.5 kV and below) will incorporate a Δ-Y, or 30 deg phase shift from the higher transmission voltages. Interconnection requests, particularly involving transformers, need to consider the phase relationship between the BPA transmission voltages and the Requester’s desired or existing system voltages.

Transformers connecting to the transmission system where a source of real power flows through the transformer to the BPA high voltage transmission system shall provide a ground source of current on the high voltage side. A YG-Δ or a YG-Δ-YG transformer with the Y-ground connection on the high voltage side can accomplish this. A YG-YG connection is only appropriate if there is a sufficient ground source on the low voltage side and will need to be evaluated by BPA before being permitted. New Δ-YG transformers with the delta connection on the high side are only permitted on radial (feeder) systems with no power flow into the BPA high voltage transmission system.

For generator interconnections where a low-impedance ground source is also desired on the generator side of the transformer, such as for a connection to a wind farm, the most typical transformer configuration is YG-Δ-YG (e.g. 230–34.5 kV). Where low-impedance grounding is not desired on the generator side, the typical configuration is YG-Δ (e.g. 230-23 kV), with the Δ connection on the generator side.

Some substations on the BPA transmission system have very high ground fault levels. Interconnection at or near these substations naturally increases these levels and the additional ground source on the high voltage side increases them further. BPA may place special requirements on the connection transformer to increase the high-side grounding impedance. This will be done to decrease the ground fault contribution of the interconnection while still maintaining acceptable high-side grounding. These requirements are determined on a case-by-case basis.

8.4.2 *Existing Installations*

Generation or transmission connections to existing ∆-YG transformers used to serve load may require additional system equipment, such as a grounding bank, to provide adequate protection against ungrounded system operation. Relay protection schemes may also be required to ensure immediate disconnection of the power source following disconnection of the transmission system components. BPA will consider these on a case-by-case basis only.

8.4.2.1 Radial 525/230 kV Transformer Installations for Generation

To meet demand for several renewable generation projects to interconnect in the same proximity in the most efficient manner possible, a radial 500/230 kV plan of service may be recommended by Transmission Planning. A position in the 500 kV yard of a new or existing BPA substation will include a 1300 MVA transformer bank (3 x 433 MVA 525/230-34.5 kV single phase auto-transformer units) with a spare 433 MVA phase to provide for interconnections at 230 kV. The spare transformer phase is required to minimize outage times if a transformer failure occurs, and provides maintenance flexibility.

In general, bulk transfers delivering generation to load centers occur across the 500 kV main grid transmission system. A radial 500/230 kV transformer (Hub) connection to the 500 kV system reduces the cumulative effects of large number of individual generation projects connecting to the 230 kV system in the area and the associated reliability mitigation issues. This plan of service injects the generation directly into the 500 kV main grid system, avoiding 230 kV system expansion and reinforcements needed to deliver the generation to the main grid. Potential overloads are limited and easier to manage across the 500 kV system. Transmission Planning will decide which plan of service is warranted based on system conditions in the area of the requested generation interconnections and the number of requests anticipated in the area.

8.4.3 *Neutral Shifts*

When generation is connected to the low-voltage, grounded wye side of a delta-grounded wye (Δ – YG) transformer, opening the high voltage connection due to fault clearing may cause overvoltage on the high voltage terminal. These high voltages 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 to avoid neutral shift and its potential problems are possible.

8.4.3.1 Effectively Grounded System

Utilize appropriate transformer connections on the high-voltage side to make the system ‘effectively grounded’. Effectively grounded is defined as a system $X0/X1 \leq 3.0$ and

R0/X1 ≤ 1.0. Any of these methods can result in an effectively grounded system that will minimize the risk of damage to surge arresters and other connected equipment. Methods available to obtain an effective ground on the high voltage side of a transformer include the following:

- A transformer with the transmission voltage (BPA) side connected in a YG configuration and low voltage side in a closed ∆.
- A three winding transformer with a closed Δ tertiary winding and both the primary and secondary sides connected YG.
- Installation of a grounding transformer on the high voltage side.

8.4.3.2 Increase Insulation Levels

Size the insulation of equipment connected to the transmission line high-voltage side to be able to withstand the expected amplitude and duration of the neutral shift. This may include equipment at other locations.

8.4.3.3 High Speed Separation

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 the overvoltage condition.

8.5 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 in, or immediately adjacent to, the station under both 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 beyond acceptable and safe limits (for example due to high soil resistivity or limited substation space), grounding rods and grounding wells may be required 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 isolated, then no metallic ground connections are allowed 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. All-dielectric type fiber optic cables are highly preferable for providing telecommunications and control between two substations while maintaining 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. BPA must approve any connection to a BPA substation ground grid.

New interconnections 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.

8.6 Station Service

Power that is provided for local use at a substation or generation facility to operate lighting, heat and auxiliary equipment is termed station service. Alternate station service is a backup or alternate independent source of AC power, used 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 BPA Grid beyond those specified in applicable NERC, WECC and NWPP Reliability Criteria.

Appropriate providers of station service and alternate station service are determined during the interconnection study and planning process, including Project Requirements Diagram development and review. Generally, the local utility will be the preferred provider of primary station service unless it is unable to serve the load, or the required facilities are prohibitively expensive. Note that even if one source of station service is backfeed via the BPA grid, the Requester must make commercial arrangements with the local utility for retail service.

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

If the Requester intends to schedule station service energy to the Project, the Requester is responsible to make arrangements for TSIN registration, appropriate Source/Sink identification, commercial transmission service and scheduling. The Requester should contact the BPA Transmission Services Account Executive at least six months prior to the desired energization date.

9. TRANSMISSION LINE DESIGN

All new transmission lines owned or maintained by BPA shall be designed to meet all current BPA design and maintenance standards, utilizing existing BPA standard cables, hardware, and structures. Transmission lines owned and maintained by customers for interconnection to BPA may utilize non-BPA standard cables. Coordinate with BPA design and customer service engineering staff to determine applicable BPA standards appropriate for the interconnection scenario. See STD-N-000011, *Equipment Ownership Requirements*, for demarcation information. Some specific transmission line requirements include the following:

9.1 ROW Width

BPA's ROW widths are based on maintaining horizontal clearances to buildings and other installations with the conductor displaced from rest by 6-psf (49 mph) wind pressure on bare conductor at 60° Fahrenheit (F) final sag. The ROW width of all new transmission lines owned or maintained by BPA shall be designed to meet BPA Standard STD-DT-000062, *ROW Width Policy*.

9.2 Lightning Protection and Grounding

All new transmission lines owned or maintained by BPA shall be designed according to BPA transmission line design standards STD-DT-000024: *Transmission Line Grounding Standard*, and STD-DT-000064: *Transmission Line Lightning Protection*. Briefly a few of the main requirements of these standards are as follows.

- To provide substation shielding and to reduce the risk of substation equipment damage from incoming lightning surges on the transmission lines, all new lines connecting to a BPA substation shall have overhead ground wires (OHGW) extend out at least ½-mile from the BPA substation for 69 kV to 161 kV and 1-mile for lines at 230 kV. See requirements below for 500 kV transmission lines. The transmission line OHGWs shall be insulated from the substation ground grid. The number of OHGWs used for shielding depend on reliability required and will be determined by BPA on a case-by-case basis.
- Interconnected substations that are adjacent, or in close proximity, to each other shall include continuous OHGW or shield wire between stations. Close proximity is defined here for 230kV and above stations that are less than 1 mile apart in line length, and stations below 230kV that are less than ½ mile apart in line length.
- All new 500 kV transmission lines shall provide shielding with one or more OHGW for the entire length of the line. These OHGW are segmented into isolated sections, insulated with single point grounds near the center of each isolated section. Each segment is limited to 8 miles for single-circuit and 3.5 miles for double circuit. Locate towers with OHGW grounding away from public-use areas.
- If the Requester proposes to tap a shielded (OHGW) transmission line, the tap line must also be shielded for its entire length. When tapping into an unshielded transmission line, the tap line shall be shielded in accordance with the requirements above; except for short taps (whose total lengths are less than the shielding lengths listed above). In this case, the tap line shall be shielded for its entire length.

9.3 Surge Protection

All lines connecting to a BPA substation shall include substation entrance surge protection, typically in the form of Station class MOV surge arresters. BPA will determine the appropriate level of surge protection as described in section 6.4.5.

Line sectionalizing switching stations or switching terminals utilizing power circuit breakers, circuit switchers or similar electronically controlled switching device shall include surge protection on both line sides.

9.4 Underbuild

BPA transmission lines are not designed to accommodate underbuilds. Site specific analysis must be completed to determine if BPA will allow an underbuild. If permitted, the permitting shall be documented with requirements set forth by a pole contact agreement.

10. CONTROL & PROTECTION DESIGN

10.1 Control and Protection Requirements

BPA coordinates its protective relays and control schemes to provide for personnel safety and equipment protection and to minimize disruption of services during disturbances. New connections usually require the addition or modification of protective relays and/or control schemes, including replacement or modification of equipment at the remote terminal(s). The new protection must be compatible with existing protective relay schemes and present standards. The addition of voltage transformers, current transformers, or pilot scheme (transfer trip) may also be necessary. If protective relaying equipment installed at the POD or POI will be maintained or operated by BPA personnel, or if these relays must communicate with BPA installed relays at remote terminals, then the BPA standard for this application must be followed. BPA will supply the Requester with protective relay system recommendations.

10.1.1 *Introduction*

The protection requirements identified in this document address the following objectives:

Specify adequate protective relays that will quickly and reliably remove faulted equipment from the power system in order to:

- Minimize disruptions to the BPA transmission system and interconnected systems
- Minimize safety risk to the public and utility personnel
- Minimize damage to power system equipment

Ensure that protective relays are reliable and meet the requirements of BPA, NERC, WECC, and NWPP.

Introduce requirements for other protection and control schemes that may be required, e.g. transfer trip, RAS, load tripping, generator tripping, underfrequency load shedding, etc.

In order to achieve these objectives, certain protective equipment (relays, circuit breakers, etc) must be installed. These devices ensure that the appropriate equipment is promptly disconnected from the BPA Grid during faults or other abnormal conditions.

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 BPA customers and potentially those of other utilities).
- The connection of a line or load that coincidentally connects a generation resource, which was not previously connected to the BPA Grid. In this case, the Requester must also follow the additional requirements for interconnection of generation resources.

BPA will work with the Requester to achieve an installation that meets the Requester's and BPA's requirements.

BPA cannot assume any responsibility for protection of Requester's equipment. Requesters are solely responsible for protecting their equipment in such a manner that faults, imbalances, or other disturbances do not cause damage to their facilities or result in problems with other customers.

10.1.2 *Protection Criteria*

The protection system must be designed to reliably detect faults or abnormal system conditions and provide an appropriate means and location to isolate the equipment or system automatically. The protection system must be able to detect power system faults within the protection zone. The protection system should also detect abnormal operating conditions such as islanding, equipment failures or open phase conditions. Special relaying practices may also be required for system disturbances, such as undervoltage or underfrequency detection for load shedding or reactive device switching. For most generation and some loads, the Requester will also be required to participate in special protection schemes or RAS including automatic tripping or damping.

10.1.2.1 General Protection Practices

The following summarizes the general protection practices as required by NERC and WECC, as well as specific practices and applications as applied to BPA transmission lines and interconnections. The protection schemes and equipment necessary to integrate the new connection must be consistent with these practices. Table 2 specifies maximum allowable operating times for protection systems and breakers by voltage category.

10.1.2.1.1 Selection and Review Considerations

The POI protection system security and dependability and the related effects on the power system must be carefully weighed when designing the protection system. BPA reserves the right to review and require changes to the POI protection system and settings.

10.1.2.1.2 Regulatory Requirements

Protective relays and their settings are required to follow various regulatory requirements such as NERC and WECC Standards. These requirements are subject to change. Although BPA attempts to provide guidance to customers regarding these requirements, BPA is not responsible for the failure of a customer's protective relay systems to meet these requirements.

10.1.2.1.3 Reliability and Redundancy

Protective relay systems must be designed for reliability and redundancy. The protection system must be capable of meeting the operating times for the appropriate voltage class specified in Table 2, and redundancy is required so that the failure of any single protection system component will not prevent the system from meeting the requirements of Table 2. This will normally require redundant relays—each with currents and voltages provided from separate secondary windings—redundant breaker trip coils, and if required by the protection scheme, redundant communication systems. Redundant station batteries are not required if battery monitoring meets NERC standards, but each set of relays must have its own separately protected DC source.

10.1.2.1.4 Instrument Transformers

The secondary relay currents and potentials to the redundant relays must be sourced from separate instrument transformer secondary windings so that the failure of one secondary winding will not disable all of the redundant relays. The use of capacitive voltage transformers (CVTs) and magnetically coupled voltage transformers (MVTs) is generally acceptable for protection purposes. The use of bushing potential devices for protective relaying may not be appropriate if the protection device includes settings for frequency deviations and overvoltages. Current transformers used for protective relaying should generally have a C800 accuracy class rating.

10.1.2.1.5 Test Switches

For relay installations that BPA will own or maintain, BPA requires a sufficient number of test switches and isolating devices to provide ease of testing and maintenance without the need for lifting wires.

For customer owned and maintained relay installations, BPA recommends sufficient test switches and isolating devices to allow ease of maintenance and testing. BPA also recommends that maintenance tagging and switching procedures be developed to prevent inadvertent trips during maintenance, or test switches or isolating devices being inadvertently left in an incorrect state.

10.1.2.1.6 Security over Ranges of Loading and System Voltage

NERC Standard PRC-023 requires that protective relays must not operate for load conditions up to 150% of the equipment rating and voltages as low as 85% of nominal. Relay settings shall not infringe upon BPA's ability to operate at maximum transfer levels.

10.1.2.1.7 Synchronizing and Reclosing

At the POI, the customer is not allowed to energize a de-energized line connected to the BPA grid without approval of the BPA dispatcher. Breaker reclose supervision (automatic and manual including SCADA) may be required at the connecting substation and/or electrically adjacent stations. This may include hot-bus and dead-line checking, synchronization checking, etc.

10.1.2.2 Protection Performance

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 verify that the selected relay works properly 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.

10.1.2.2.1 Phase Fault Detection

The relay system must be able to detect multi-phase faults and trip at high speed for high fault currents. Non-directional overcurrent, directional overcurrent, distance, and line differential relays may be applicable depending on system requirements.

Infeed detection to faults within the power system usually requires directional current-sensing relays to remove the contribution to the fault from the POI. The distance relay (IEEE device 21) is a good choice for this application since it is generally immune to changes in the source impedance.

10.1.2.2.2 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.

10.1.2.2.3 Breaker Failure Protection

Breaker Failure Protection is required on all breakers at transmission voltage, which BPA defines as 69 kV and above. For three-cycle or faster breakers, the breaker failure relay is generally set to trip if the fault has not been cleared within 8 cycles after the relay trip command. Breaker failure relays are not required to be redundant.

10.1.2.2.4 Islanding

Intentional islanding is a utility practice to deliberately choose to isolate its distribution system and use local generation to feed loads during transmission system outages.

Unintentional islanding describes a condition in which the power system splits into isolated load and generation groups, usually when breakers operate for fault clearing or system stability remedial action. Delayed fault clearing, overvoltages, ferroresonance, extended undervoltage and off-nominal frequency operation, and degraded service quality for other customers can result from a local unintentional islanded condition.

BPA does not allow unintentional islanding conditions to persist that include its facilities, except for a controlled, temporary, area-wide grid separation. Where generation is connected to the BPA transmission system, implications of unintentional islanding must be addressed to minimize adverse impacts on connected loads.

Generation facilities equipped with over and under frequency (81O/U) and over and under voltage (59/27) protective relays may also use those relays to partially meet BPA's requirements to detect and trip on unintentional islanding conditions. Settings for these relays shall be in accordance with WECC underfrequency load shedding requirements. BPA reserves the right to require more extensive unintentional islanding protection.

10.1.2.2.5 Relay Performance and Transfer Trip Requirements

Relay systems are designed to isolate the transmission line and/or other facilities from the BPA Grid. However, the performance (clearing time) of local relay systems and the associated isolating devices (circuit 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.

In general, protective relay schemes at 230kV and above require the relays to be capable of providing an instantaneous trip for faults anywhere on the protected line. This will require some type of pilot communications to insure secure, high-speed fault clearing. Lower voltages may also require pilot communications to insure secure, high-speed fault clearing. BPA normally uses direct under-reaching and permissive overreaching transfer trip for its pilot schemes, but other types of pilot tripping such as directional comparison, phase comparison or current differential may also be acceptable if the chosen scheme can achieve the total clearing times required and is compatible with the selected method of pilot communication.

There are several other situations that will require a transfer tripping scheme to facilitate the operation of a remote breaker. Some of these situations are given below.

- Transient or steady-state studies identify conditions where maintaining system stability requires immediate high-speed separation of the POI facility from the power system.
- Special operational control considerations require immediate separation of the POI from the BPA Grid.
- Extended fault duration represents an additional safety hazard to personnel and can cause significant damage to power system equipment.

- Slow clearing or other undesirable conditions such as extended overvoltages or ferroresonance 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 BPA circuit that connects other customer loads become part of an unintentional island that includes a generator.
- When remote circuit breaker tripping is required, in order to clear faults in a transformer not terminated by a high side breaker, high-speed transfer tripping will be required. The transfer trip may also be required to block automatic reclosing. Other unique configurations may impose the same requirement.
- Relay operate times are adjusted to coordinate for faults on the local configuration such as a three terminal lines, fault currents available, etc. Total clearing times must be less than those listed in Table 2. Refer to Section 11 for telecommunication issues as they pertain to control and protection requirements.

10.1.2.2.6 Synchronizing and Reclosing Requirements

Synchronizing and reclosing requirements can vary widely depending on the specific circumstances. For radial feeds, single- or multi-shot reclosing is generally allowed for single- or multi-phase faults. For network transmission lines, reclosing is generally limited to a single shot for 230kV and above lines, and only for single-phase faults for 500kV lines. A minimum dead time of 35 cycles is required. If the new connection results in the possibility of connecting a generation source, special considerations may be required. Section 14.6 identifies synchronizing and reclosing requirements specifically related to generator additions.

If a connection is made to an existing line, automatic reclosing schemes at the remote line breakers may need to be modified. On transmission lines below 138 kV, automatic-sectionalizing schemes may be installed to isolate a portion of the system that has a permanent fault. This includes multi-shot automatic reclosing at remote terminals. A new interconnection should be compatible with such existing schemes.

Table 2.— Relay and Breaker Operating Times by System Voltage

Connection Voltage (Line-Line rms)	Total Clearing Time (Cycles)	Maximum Relay Operate Time (Cycles)	PCB Trip Time (Cycles)	Time Delayed Tripping Acceptable?
< 100 kV	≤ 12-14*	≤ 4-6*	≤ 8	Yes
100 to 138 kV	≤ 7-9*	≤ 2-4*	≤ 5	Yes
161 to 230 kV	≤ 5-7*	≤ 2-4*	≤ 3	Yes
230 kV Main Grid to 345 kV	≤ 4	≤ 1	≤ 2	No**
500 kV	≤ 4	≤ 1	≤ 2	No**

* Relay operating and total clearing times are for instantaneous element trips at the terminal closest to the fault. Inverse time and time delayed elements are considerably longer. Sequential instantaneous or time delay tripping may occur at the remote terminal.
**Transfer trip or other communications aided-tripping is required.

10.1.3 Protection System Selection and Coordination

10.1.3.1 Protection Requirements for the Interconnecting System

Upon request, BPA will supply the Requester with a list of protective relay systems considered suitable for use at the POI. Should the Requester select a relay system not on the approved list, BPA 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. If there are special performance requirements for the protective relays at the POI, BPA will notify the Requester.

10.1.3.2 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 POI, 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 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 or other relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible. These relays must meet NERC and WECC standards for relay loadability.
- Protection systems should prevent tripping for stable swings on the interconnected transmission system. During a system disturbance, power swings may result which can affect operation of protective relays, especially distance relays. Out-of-step blocking is commonly applied to distance relays to prevent inadvertent operation during a power swing. However, the application of such schemes must be coordinated with BPA to assure that blocking the distance elements will not result in the inappropriate or undesirable formation of islands.
- 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.

10.1.3.3 Relays for the Point of Interconnection

The following list of relays has been developed in recognition of varied interconnection requirements. Relay performance under certain fault scenarios is also a consideration in the selection of these relays. The specific relays used must be functionally consistent with and complementary to BPA's general protection practices identified in Section 10.1.2.

The relay functions generally necessary to serve this purpose as used by BPA include:

Phase overcurrent (non-directional)	(50/51)
Neutral overcurrent (non-directional)	(50/51-N)
Zone distance (phase or phase and ground distance)	(21/21-N)
Directional ground overcurrent	(67-N)
Ground overcurrent	(51-G)
Or ground fault detection scheme	(59-Z)
Over/under voltage	(59/27)
Over/under frequency	(81)
Instantaneous overvoltage (ungrounded high side)	(59)
Remote automatic breaker reclose supervision	(79-X)
(HB/DL, HB/HL with synchronism check)	
Current differential	(87)

Except as otherwise agreed by BPA, BPA will furnish, install, operate and maintain all relaying at the POI for the purposes of protecting the BPA Grid. Other relaying for protection of the Requester's equipment will be the responsibility of the Requester. All relays, which can adversely affect the BPA Grid, shall be 'utility grade' quality, subject to review by BPA.

Refer to Section 11 for telecommunication issues as they pertain to control and protection requirements.

10.1.4 *Generator Protection - Special Requirements*

Integration of new generation has special requirements in addition to the previously described protection requirements. This section primarily deals with the protection requirements for the integration of synchronous and asynchronous rotating machines. Wind turbine installations require special considerations. The actual protection requirements and choice of relay type will vary depending upon several factors:

- MVA capacity of the generation
- Generation Type: synchronous or asynchronous
- Location of the generation interconnection on the transmission grid

- Voltage level of the generation interconnection
- Transformer winding configuration for the generator step-up transformer and/or interconnecting transformer
- Change in the fault current capacity as a result of the added generation
- Availability of telecommunications facilities

Examples of some typical generator integration plans are shown in Table 3 and Figure 5 through Figure 9. Table 3 identifies only the protection equipment, which may affect the operation of the BPA Grid. The type of resource proposed and location of the POI will determine any special protection requirements for other types of resources, such as photovoltaic, wave, etc.

10.1.4.1 Fault Protection

Protective relays are required to detect phase and ground faults on the generator interconnection. The relay systems shown in Figure 5 through Figure 9 are designed to isolate the generator from the BPA grid at or near the POI. However, the performance (clearing time speed) of these local relay systems and the associated isolating devices (circuit breakers, circuit switches etc.) will vary. In most cases, protective devices described in Section 10.1.3 will also be appropriate for this interconnection.

Ground fault detection has varying requirements. The most significant consideration in the ability to detect ground faults on the BPA Grid is the winding configuration of the transformer connecting the generator to the grid. The scenarios below assume that the generator is connected to the low-voltage side of this transformer.

10.1.4.1.1 Transformer Grounded Wye (YG) Connection on the BPA Grid Side

This is the BPA required transformer connection when adding a new generation resource to the transmission grid. The transformers will either be YG-Δ or YG-Δ-YG. Either of these connections provides a solid ground source for the transmission grid.

For a transformer connected with a grounded-wye on the primary (high-voltage) side, a ground overcurrent relay (50/51-G) connected in the neutral of the wye winding provides transmission fault detection. This relay also protects the transformer.

A directional ground overcurrent relay (67-N) is generally provided for detection of ground faults in the transmission system when transformer connections are of the types identified above. Since this relay function complements zone-distance protection used for phase fault detections, it is included in many presently manufactured relays. See Figure 5, Figure 6 and Figure 9 for typical examples of this configuration.

10.1.4.1.2 Transformer Delta (Δ) Connection on the BPA Grid Side and Potential Overvoltages

Some smaller generation projects are proposed for integration into existing utility power systems through a delta transformer connection to the transmission grid. This Δ-YG transformer was originally designed only to serve loads; e.g., connection at the 12.5 kV side of the 115 kV/12.5 kV transformer. This common transformer configuration requires special relay considerations when generation is proposed for connection to the low voltage terminal. The existing protection at these installations was applied under the assumption that there was not a source from the low-voltage side to infeed to faults in the power system. BPA will review all such requests on a case-by-case basis to determine acceptability. New relays, transfer trip, ground detection equipment, or a grounding transformer may be required to assure timely removal of the generation source for safe clearing of faults on the transmission system. Figure 7 and Figure 8 show examples of this configuration.

Table 3.— Relay Functions for Figure 5 through Figure 9

Interconnecting Substation, High Voltage Transmission Line Protection		
The following relays are intended for the interconnecting substation to detect faults on the BPA Grid and isolate the interconnecting substation from the BPA Grid.		
Figure	**Relay**	**Intent**
5, 6, 8, 9	21 -1, 21-2/62	Distance relays trip line breakers for multi-phase faults on the transmission lines to the Interconnecting Substation. Ground distance relays may be used for ground faults. These relays may have single pole switching capability. They also may be connected to a transfer trip or other pilot channel. More than two zones may be required.
5, 6, 8, 9	67N	Directional ground overcurrent relay trips line breakers for ground faults on the transmission lines to the Interconnecting Substation. These relays may have single pole switching capability. They also may be connected to a transfer trip or other pilot channel. Potential polarization: shown in the figures. Current polarizing or negative sequence polarizing may also be used.
5, 6, 8, 9	87	Line differential relays are often necessary to avoid coordination problems with other relays to limit nuisance trips of the generator. Distance relays (21), directional overcurrent ground relays (67N), and a permissive overreach transfer trip may also be used.
5 -9	79X	Automatic reclose supervision is necessary at the interconnecting substation and/or the remote high voltage substations when a generator is added. This includes a hot bus/dead line (HB/DL) check and a synchronism check. The automatic reclose supervision will prevent the transmission line from reclosing if the generator remains in service and is not in synchronism with the BPA Grid.
7, 8	59	This relay detects overvoltages, and ground faults as indicated above. With an instantaneous trip at 1.5pu overvoltage. It is provided to avoid arrester failure for ground faults. This scheme is most often required when the interconnecting substation includes a Δ-YG transformer.
Interconnecting Substation, Transformer Protection		
The following devices are typically used at the interconnecting substation to provide protection of the power transformer that interfaces between the generator and the BPA Grid.		

Figure	Relay	Intent
7, 8	59 Z	A ground fault detection scheme is used to detect ground faults on the tapped transmission line. (Normally the open delta 3V0 scheme with inverse time characteristic). Trips of this relay may need to be time coordinated with other relays so that faults beyond the tapped transmission line do not cause unnecessary trips of the generator feeder. This scheme is most often required when the interconnecting substation includes a Δ-YG transformer.
7	Fuse	Some existing Δ-YG transformers may have high side fuse protection. This is generally not acceptable for new installations.
5 -9	50/51, 50/51 N	These relays protect transformers from overcurrent conditions caused by low side faults extreme overloads or unbalances. Phase overcurrent relays are usually set to pickup at approximately twice the transformer thermal rating. These relays are time-coordinated with low side feeder relaying. Voltage restrained time overcurrent relays may be used instead of the standard 50 element. 50/51 relays may also provide backup for transformer 87 relays.
5, 6, 8, 9	50/51 G	This relay protects transformers from overcurrent conditions caused by low side ground faults or extreme unbalances. These relays are time-coordinated with low side feeder relaying.
5 -9	63	Sudden pressure or Buchholz relays may also be provided for the transformer.
5 -9	87	Transformer differentials relays may be used for transformer protection.
Generator Interconnection		
The following relays are required at or near the generation. These relays do not provide fault protection for the generator itself, which is the responsibility of the generator owner.		
Figure	**Relay**	**Intent**
5 -8	25	This relay provides synchronism check supervising function for generator breaker close circuits.
5 -9	27/59	These relays detect abnormal voltage conditions often caused by unintentional island operation scenarios. The undervoltage relay can serve as a means of fault detection for instances of weak fault current infeed from generator to faults on the feeder or interconnected system. It protects generator against extended operation at abnormal voltages. Undervoltage relay settings are coordinated with Pacific Northwest undervoltage load shedding plan.
5 -9	81	This relay detects abnormal frequency conditions, often caused by unintentional island operation scenarios. It protects generator against extended operation at abnormal frequencies. Underfrequency relay settings are coordinated with the WECC and NWPP underfrequency load-shedding plan.

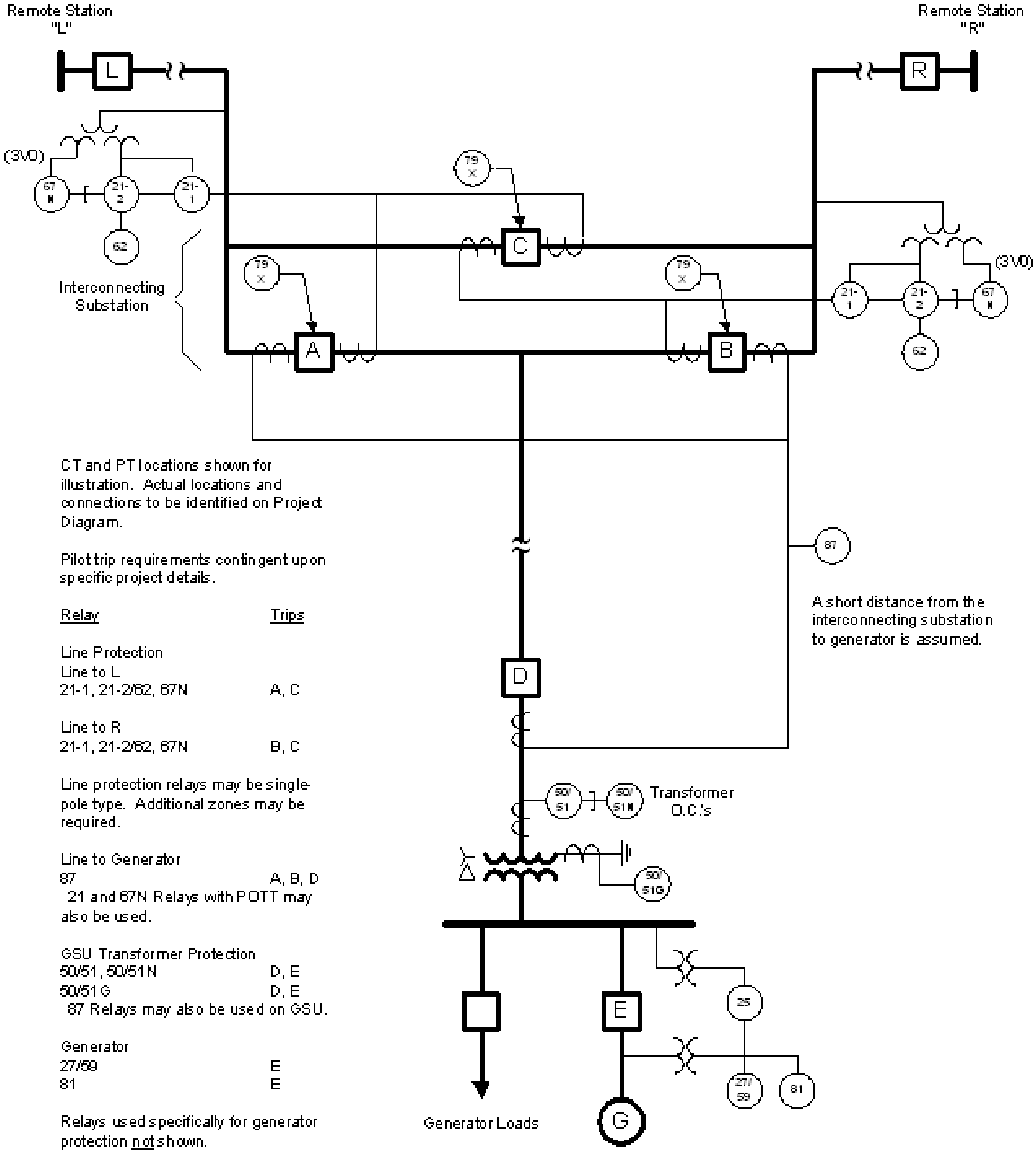

Figure 5.--- Integration of Generation into a Transmission Level Substation

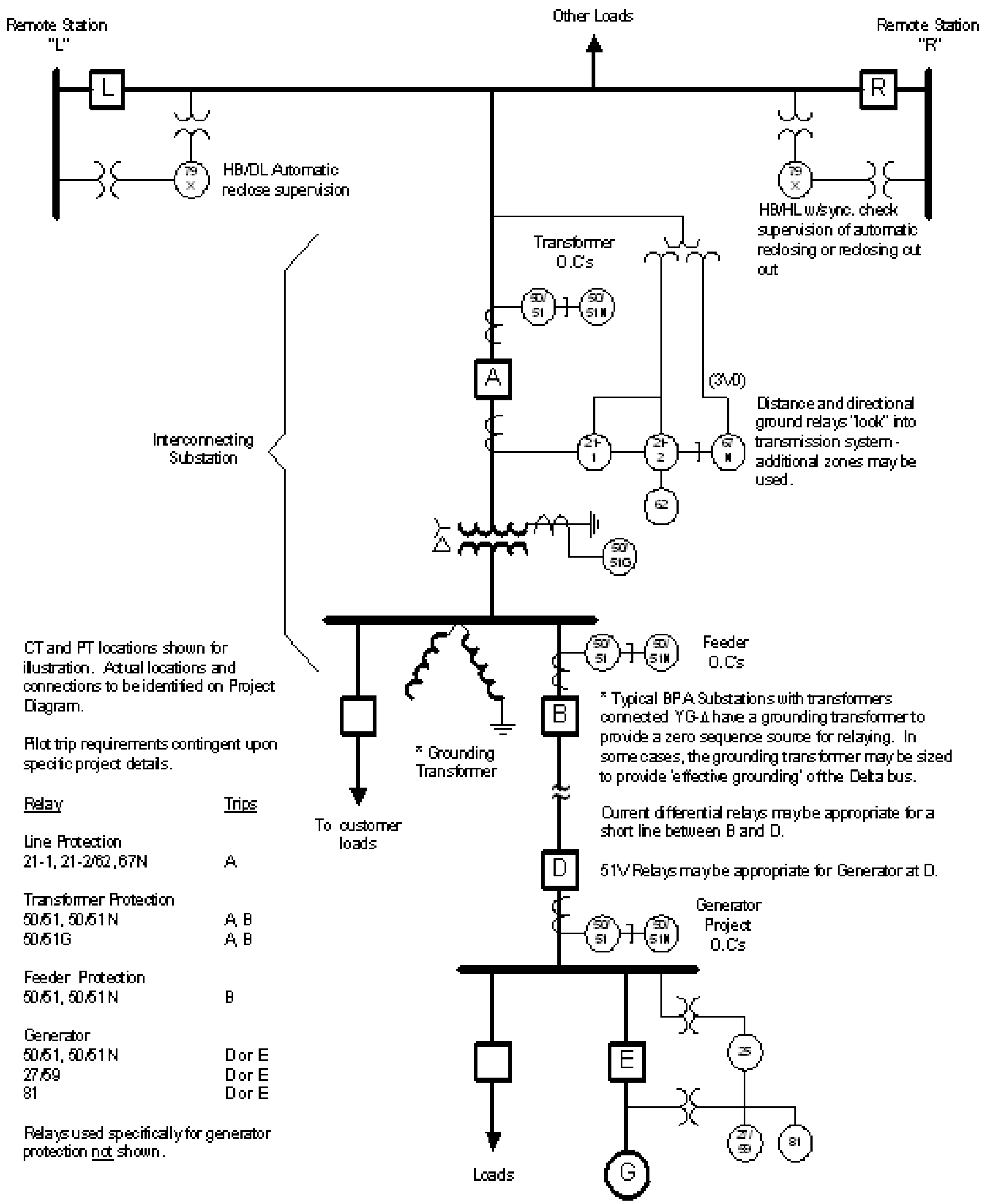

Figure 6.--- Integration of Generation into a Low Voltage Substation Protected by a High Side Circuit Breaker and Connected to a Transmission Line Through a YG-Δ (as shown) or YG-Δ-YG Transformer

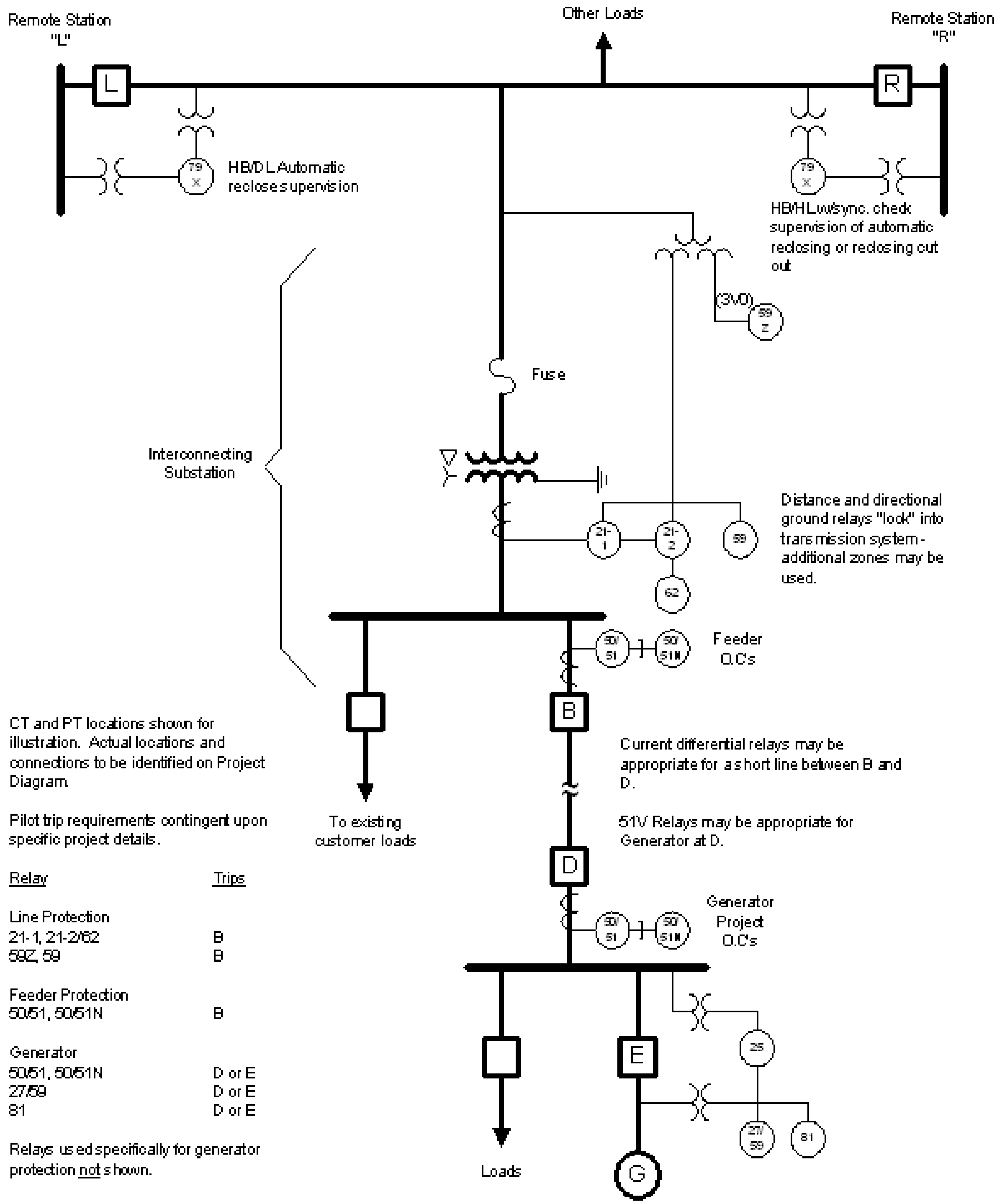

Figure 7.--- Integration of Generation to an Existing Low Voltage Substation Connected to the Transmission line Through a Fused Δ-YG Transformer

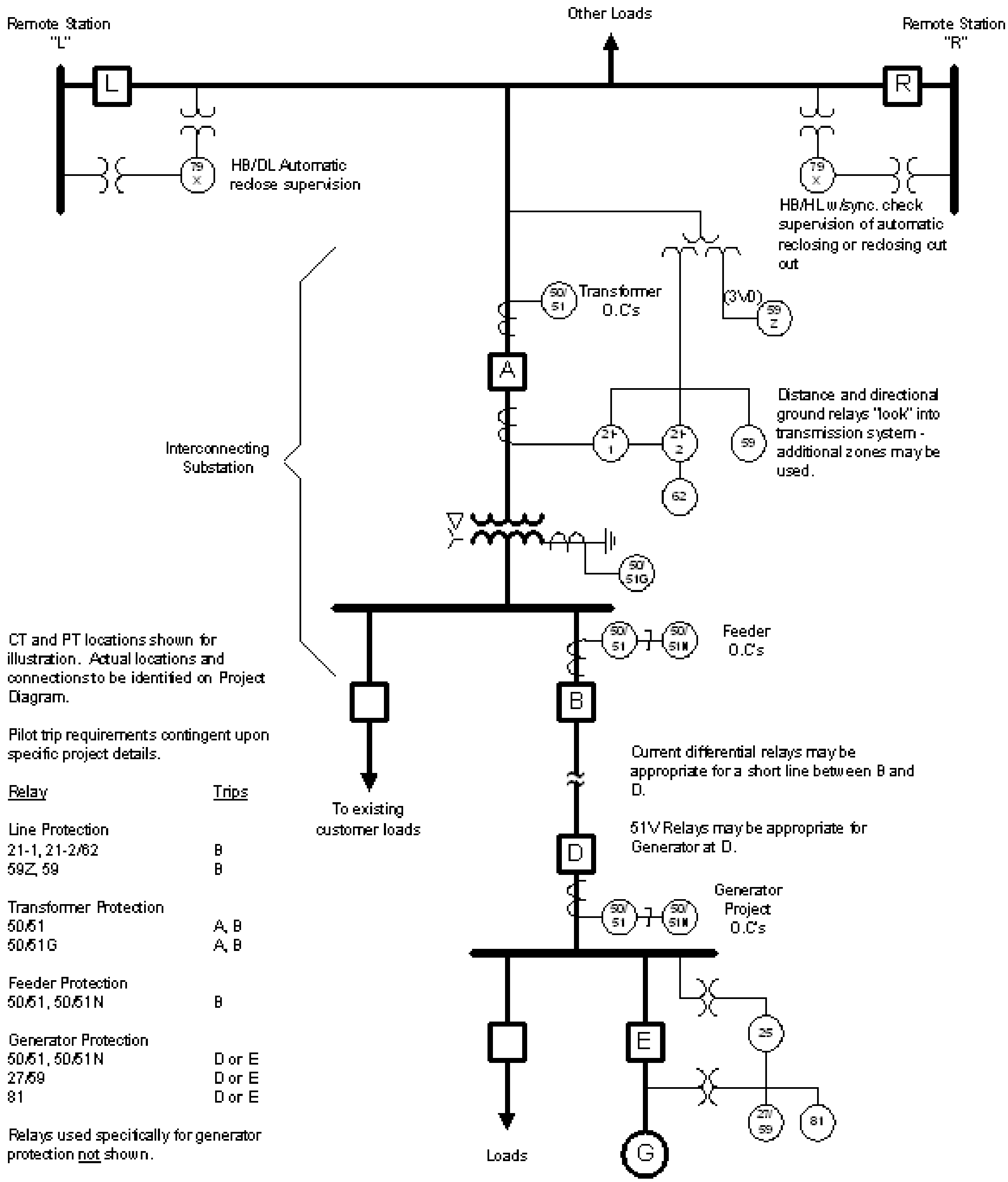

Figure 8.--- Integration of Generation to an Existing Low Voltage Substation Connected to a Transmission line a Δ-YG Transformer and Protected by a High Side Circuit Breaker (Switcher)

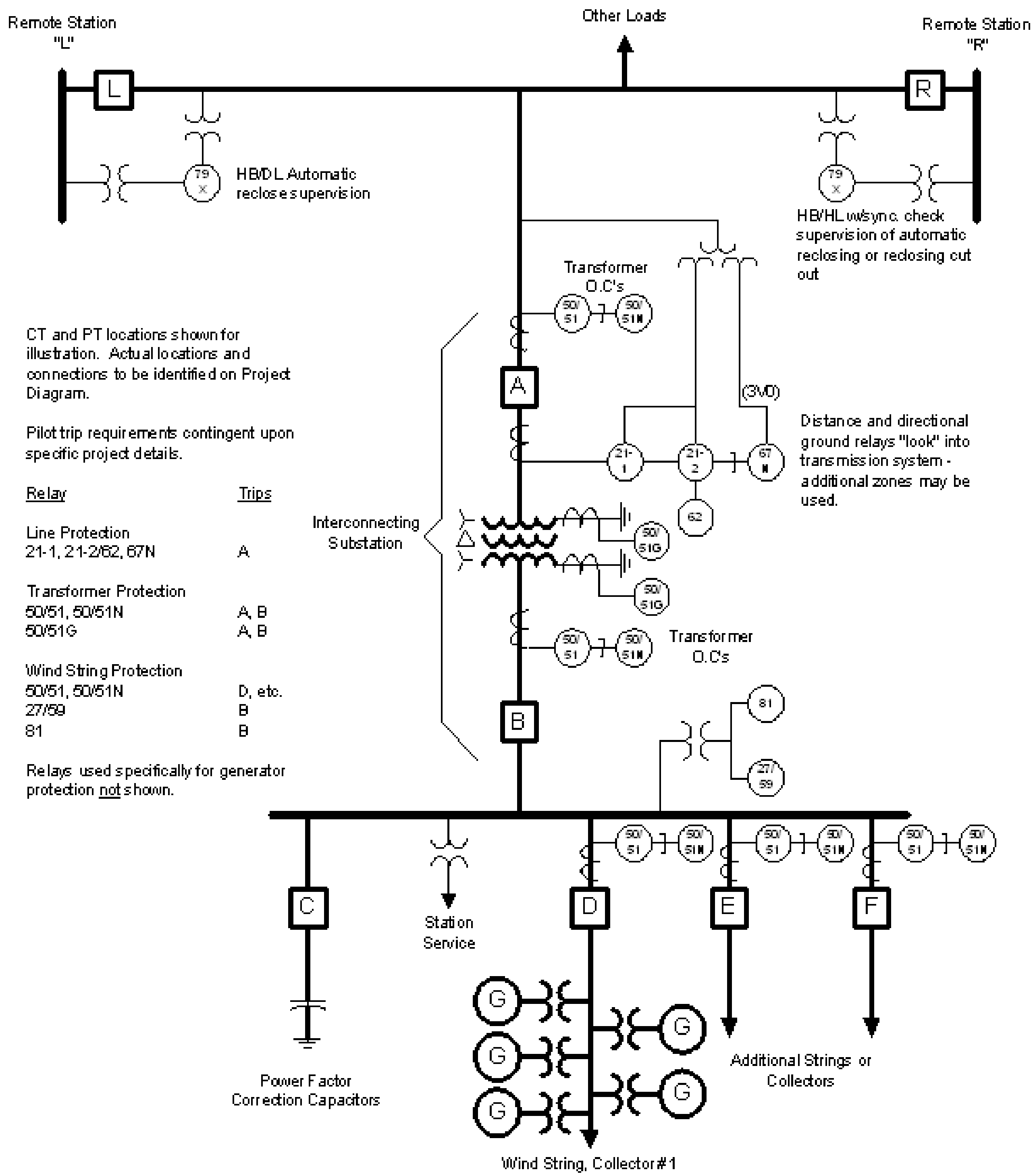

Figure 9.--- Integration of a Typical Wind Generation Facility to a 69 kV or 115 kV Transmission Line Through a YG-Δ-YG Transformer

10.1.4.1.3 Potential Overvoltages with Delta Connection on the Transmission Side

For ground faults on the high voltage system, protective relaying at the transformer cannot detect zero sequence current at this location unless a ground source (grounding bank) is connected to the high-voltage side of the transformer. Circuit breaker operation(s) at the remote terminal(s) of the transmission line will isolate the line. However, the generator will continue to energize the transmission line creating a 'local island' condition described previously. With one phase grounded, energizing from the transformer low side can result in significant overvoltages (neutral shift) on the unfaulted phases of the transmission line.

It is normally assumed that these overvoltages would equal 1.7 pu. However, studies indicate that the voltages on the unfaulted phases of the transmission line can be even higher than the 1.7 pu, particularly if the generation is large compared to the local load that is islanded with the generator when the line-end breakers trip.

When induction machines are at or near full load, there is usually a considerable amount of capacitance also in service to keep the delivered power factor near 1.0. When the transmission line breakers open, the generator(s) are suddenly unloaded, and there is generally enough capacitance to make the induction machines self-excite. This, in combination with the line capacitance, will cause the voltage to increase above one (pu) at the generator terminals and consequently on the transmission line.

When a synchronous generator is at full load, the excitation system creates a high equivalent internal voltage, supplying the necessary vars to keep the overall delivered power factor near 1.0 and assist with local voltage control. When the system breakers open, unloading the generator, the high internal excitation will increase the voltage on the generator terminals and on the transmission line.

If the generator rating is about the same as the local load on the islanded transmission line, additional overvoltages above 1.7 pu would not be expected. Studies show that if the generator rating is considerably smaller (1/3 or less) than the minimum local load, then the voltage on the islanded system should quickly collapse.

10.1.4.1.4 Acceptable Solutions to Transmission Line Overvoltages

Overvoltages can potentially fail lightning arresters and other equipment connected to an isolated transmission line. There are three acceptable solutions to resolve the potential overvoltage problems resulting from the Δ-YG transformer neutral shift following a line to ground fault on the transmission line.

- High Side Grounding
- The best and preferred solution to eliminate the 1.7 pu overvoltages is to replace the Δ-YG transformer with a YG-Δ or YG-Δ-YG transformer or install a separate ground source on the transmission line. Wind turbine sites usually require a grounded distribution or collection system, so the YG-Δ-YG transformer configuration is

necessary. See Figure 9. If the transformer configuration is changed or a separate grounding transformer added, overcurrent protection similar to that described in Section 10.1.4.1.1 can be used.

- Transfer Trip
- Transfer trip is installed from the circuit breaker(s) that clear the transmission line to breakers that can isolate the generator. The breaker that is used for this separation should be as fast as available. One of the line end breakers may even need delayed trip to insure that it clears last, preventing islanded generator operation. Transfer trip is usually necessary when the high side grounding solution is not feasible or for an existing station with a delta connected high side transformer winding. Transfer trip may still be required, even with high side grounding, to meet special protection and/or remedial action requirements.
- Broken Delta 3V0 Voltage Detection Scheme
- It may be possible to use a zero sequence overvoltage (3V0-59) relay connected to the high side of the ∆-YG transformer to detect this ungrounded operation. The 3V0 protection scheme uses three voltage transformers on the primary side of the transformer connected phase-to-ground. The voltage transformers must have a full line-to-line voltage rating and must be capable of measuring voltages up to 1.9 pu voltage continuously. The relay initiates a trip to eliminate the generator infeed on the faulted line. BPA will review each application to determine the acceptability of this scheme. If the 3V0 voltage detection scheme is selected, it may also require the replacement of lightning arresters on the transmission line. The new arresters require a higher rated voltage and higher temporary overvoltage capability properly sized to withstand the expected overvoltage conditions. Other high-voltage line-to-ground equipment that may be damaged by the overvoltage also needs to be replaced.
- The 3V0 open delta scheme cannot protect for the case of overvoltages created when a small generator is isolated in a ‘local island’ with a relatively large amount of capacitance, such as a long line or a capacitor bank. Under and overvoltage relays (27, 59) measuring each phase voltage may be used in conjunction with the 3V0 overvoltage relay to provide additional protection for these conditions.

If a transfer trip scheme or 3V0 scheme is selected to detect a ground on the transmission side of the step-up transformer, it is also critical that the device trip a circuit breaker on the low voltage or grounded side of the step-up transformer. Neutral shift on the high side can limit the interrupting capability of high side devices, possibly causing failure. The number of low side devices allowed to trip for a high side fault may be a consideration. BPA reserves the right to require additional equipment, such as a low side circuit breaker on the transformer, to minimize the number of devices tripped.

10.1.4.2 Synchronizing and Reclosing

The generator operator is responsible to synchronize the unit to the BPA Grid. See Section 14.6. Circuit breakers under the control of the BPA, required to maintain system integrity, shall not be used for synchronization. The BPA Dispatcher must give the generator operator permission before a generator is synchronized to the BPA Grid. All circuit breaker closing operations must automatically synchronize the generator to the transmission system.

If the generator connects to an existing line, automatic reclosing schemes at the remote terminals require modification to accommodate the generator interconnection. A hot bus/dead line check is usually applied at one terminal before attempting an automatic reclose. Hot bus/hot line with synchronism check supervision is necessary for automatic reclosing at the other terminal.

10.1.4.3 Required Relay Settings for Generators Connected to the Transmission Grid

Voltage and frequency relays used for protecting a generator and preventing an unintentional island condition from persisting must meet the requirements listed below to allow proper coordination with the power system. These relays are usually installed at the generation site or at the interconnecting substation. See Section 10.1.2.2.4.

The ranges, settings, and delays below for both voltage and frequency relays are understood by BPA to be well within the capabilities of small and large modern steam turbines as well as other generators. BPA will evaluate proposed alternative voltage/frequency settings based upon the impact on system performance and reliability. The settings must comply with existing WECC and NERC requirements.

10.1.4.3.1 Voltage Relays (27, 59)

The over/under voltage relay setting/delays listed below are intended to insure that generators trip when the connections to the power system have been interrupted, preventing extended unintentional islanding. However, minimum time delays before tripping are required to allow generators to ride through temporary low or high voltages that result from system faults or other transient events. The table below shows these minimum time delays and follow the voltage ride-through requirements of NERC PRC-024.

In areas where under-voltage load shedding plans are in use it is critical that generators do not trip prior to the completion of all automatic undervoltage load shedding. BPA may require additional time delays to those shown below on generation applied in an area which is part of an under-voltage load shedding plan.

Overvoltage (59)

Voltage	Action
≥1.200 pu	Instantaneous tripping allowed
≥1.175 pu	0.20 second minimum delay before unit tripping
≥1.150 pu	0.50 second minimum delay before unit tripping

≥1.100 pu	1.00 second minimum delay before unit tripping
<1.100 pu	no over-voltage tripping allowed

Undervoltage (27)

Voltage	**Action**
<0.45 pu	0.15 second minimum delay before unit tripping
<0.65 pu	0.30 second minimum delay before unit tripping
<0.75 pu	2.00 second minimum delay before unit tripping
<0.90 pu	3.00 second minimum delay before unit tripping
≥0.90 pu	no under-voltage tripping allowed

10.1.4.3.2 Frequency Relays (81)

If a generator facility includes a frequency relay (81) for under and/or overfrequency protection, the frequency settings and time delays must coordinate with the underfrequency load shedding plan. The frequency ranges and minimum setting/delay requirements for over/under frequency relays (81), shown in Table 4, were established by the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Program and the NWPP Enhanced Underfrequency Load Shedding Program and have now been incorporated in NERC Standard PRC-024. The objective of these settings is to use the machine capability to support the power system and prevent unnecessary loss of system load during disturbances, and ultimately, to help prevent system collapse. Generating resources must not trip off before load is shed by underfrequency relays. A generator should not be tripped by frequency relays for frequencies between 59.4 Hz and 60.6 Hz. For frequencies equal to or below 57.0 Hz or above 61.7 Hz there are no special requirements for tripping times. Table 4 specifies the under and overfrequency limits and minimum time delays. The intent is to coordinate generator tripping with load shedding schemes.

Table 4.— Under and Overfrequency Relay Settings and Operate Times

Underfrequency Limits (Hz)	Overfrequency Limits (Hz)	Minimum Time Delay Setting
60.0 > f > 59.4	*60.0 < f < 60.6*	*No generator tripping allowed*
59.4 ≥ f > 58.4	60.6 ≤ f < 61.6	3 minutes
58.4 ≥ f > 57.8	61.6 ≤ f < 61.7	30 seconds
57.8 ≥ f > 57.3		7.5 seconds
57.3 ≥ f >57.0		45 cycles
f ≤ 57.0	f ≥ 61.7	Instantaneous trip

For generators that are not susceptible to damage for the frequency ranges listed above (e.g. typical hydro units), tripping above 61.7 Hz and at or below 57.0 Hz, with no intermediate steps is suggested. For steam turbines and similar units, relay(s) with multiple frequency setpoints and discrete time delays could be used to realize the settings above.

Often, large generation resources are directly connected to a substation at the transmission level voltage and would not be part of the unintentional islanding condition previously described in Section 10.1.2. For these generators, the 61.7 Hz trip level may be raised and the 57.0 Hz trip level may be lowered. However, the minimum delays listed above for all frequency deviations from 60 Hz must be maintained. For those generators that may become part of an unintentional island, a maximum delay of 0.1 sec at ≤57.0 Hz and >61.7 Hz should be used. This will help insure that the generator trips for the unintentional island condition.

Voltage and frequency relays must have a dropout time no greater than two cycles. Frequency relays shall be solid state or microprocessor technology; electro-mechanical relays used for this function are unacceptable.

10.1.4.4 Generator Relays

Except as specifically identified in these technical requirements, BPA does not have requirements for the type of protection used for a generator. Generator protection is the responsibility of the Requester. However, the protection should meet the general requirements of NERC and WECC Standards. The level of redundancy and overlap of protection schemes are determined by the Requester. BPA's primary concern with generator protection is that the protection is available to isolate a generator fault from the BPA Grid. Types of protection used to isolate a generator from the BPA Grid include:

Percentage differential	(87)
Phase balance current	(46)
Phase sequence voltage	(47)
Reverse power	(32)
Thermal	(49)
Loss of field	(40)
Over-spped device	(12)
Transformer sudden pressure	(63)
Voltage controlled/retrained o.c.	(51-V)
Volts per Hertz (overexcitation)	(24)
Neutral overvoltage	(59-N)
Under-, overvoltage relays	(27, 59)*
Under-, overfrequency relays	(81)*

*The settings of 27, 59 and 81 relays must be reviewed and approved by BPA.

10.1.5 *Special Protection or Remedial Action Schemes*

Connections to the BPA Grid may require special protection or Remedial Action Schemes (RAS). BPA determines the RAS requirement during the interconnection studies. All Wide Area Protection RAS schemes must be fully compliant with WECC Class 1 requirements. WECC RAS criteria specifies that there be “no credible single point of failure” that would keep the scheme from operating, which, in most cases, requires geographically diverse communication paths. Redundancy or equivalent, as determined by BPA, is required for all RAS. WECC compliant RAS schemes must also be tested regularly by BPA personnel. BPA’s Wide Area Protection RAS target functional test date is Annually, with a do not exceed date of two years. BPA’s Local Area Protection RAS target functional test date is every 5 years with a do not exceed date of 75 months. BPA reserves the right to alter the test frequency for all RAS as rules change at WECC. BPA selects the timing of the RAS functional test during times of low transmission system stress in the area protected by the RAS. The most common special protection schemes include load shedding, line loss detection, and generator tripping.

BPA staff will design the RAS schemes to ensure the design meets BPA and WECC requirements.

The Requester is expected to provide sufficient rack space in their facilities to accommodate additional equipment for relaying, telecommunications, special protection or RAS Schemes needed to facilitate the interconnection.

10.1.5.1 Load Shedding

The proposed connection may require special load shedding schemes based upon BPA 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 resources, reduce the possibility of voltage collapse, and to minimize the impact of a system disturbance. Underfrequency load shedding generally includes a coordinated restoration plan, which is intended to minimize frequency overshoot following a load shedding condition. Tripping levels, restoration, and other details of load shedding schemes will be determined by BPA, following NERC, WECC and NWPP criteria. Section 10.1.4.3 includes specific requirements for generation tripping by voltage and frequency relays.

10.1.5.1.1 Direct Load Tripping

Direct load tripping may be required for large loads, typically in excess of 50 megawatts. Direct load tripping is achieved with the use of redundant, dedicated transfer trip schemes from the remedial action scheme controllers to the load. Communication channels should be alternately routed. BPA Dispatchers will enable or disable direct load tripping schemes depending upon system conditions.

10.1.5.1.2 Underfrequency Load Tripping

Underfrequency load tripping may be required to balance generation resources and loads. Underfrequency load shedding must meet the following requirements:

- Electromechanical frequency relays (81) are not allowed.
- Frequency relays should utilize the definite time characteristic.
- Total operate time for underfrequency load tripping, including circuit breaker tripping, shall not exceed 14 cycles.
- The frequency relay should be voltage supervised to prevent operation when the bus voltage drops below 0.7 pu voltage.
- The frequency element (81) may be included as a part of a multifunction protective relay.
- Frequency setting levels will be supplied by BPA.
- Load restoration settings will be supplied by BPA.

10.1.5.1.3 Undervoltage Load Tripping

Undervoltage load tripping may be required to prevent possible voltage collapse on loss of major transmission paths or generation resources. Undervoltage load shedding must meet the following requirements:

- Electromechanical voltage relays (27) are not allowed.
- Voltage relays should utilize the definite time characteristic.
- The voltage transformer source for the voltage relay (27) must be on the source side of any automatic load tap changers or voltage regulators.
- A three-phase voltage element must be used to detect the undervoltage condition. Averaging of the three phase voltages is not acceptable.
- The undervoltage element (27) may be included as a part of a multifunction protective relay.
- The undervoltage relay should not operate for a single-phase low voltage nor for a three phase low voltage below 0.5 pu.
- Total operate time for undervoltage load tripping shall be greater than expected fault clearing times, typically 30 cycles or 0.5 seconds.
- Voltage setting levels and operate time delays will be supplied by BPA. Typical settings may be in the range of 0.9 to 0.92 pu voltage with a delay of 3.5 to 8 seconds.
- Restoration settings will be determined by BPA.

10.1.5.2 Generation Tripping

New generation installations are required to participate in any Remedial Action Scheme required to assure reliability of the transmission system. BPA uses RAS generator tripping to maintain dynamic stability, voltage stability, and prevent transmission system overload. BPA Dispatchers arm and disarm generator tripping schemes based upon system conditions. RAS schemes must be fully redundant. BPA RAS controllers will send generator reduction signals to the generators via redundant transfer trip channels. If the new connection includes generation not previously part of the BPA Control Area, the generation may also require additional special trip schemes and RAS arming procedures. These schemes typically require a sequential events recorder as described in Section 10.1.6.1

It is the plant operator's responsibility to develop and maintain procedures for RAS arming of the individual generator units, and procedures for plant restoration following a RAS action.

10.1.5.3 Transmission Line Loss Detection Logic

To sense an outage that would trigger RAS action, transmission lines may require Line Loss detection Logic, (LLL). Line loss is typically sensed by the position of the circuit breaker (52/b) auxiliary switch, isolating disconnect switch status, and also from the circuit breaker trip bus. Substation bus configuration and the type of protective line relaying will determine the exact requirements for implementing line loss detection logic. Line loss sensing must be implemented at all terminals of the transmission line. Line loss detection is sent to the appropriate BPA RAS controllers via redundant telecommunications channels.

10.1.5.4 Other Special Protection and Control Schemes

The location of the POI, the amount of load or generation expected, and various other system conditions may require special protection schemes. The need for and type of schemes required are determined during the interconnection studies. For example, RAS may be required for stability purposes or out-of-step tripping may be needed for controlled system grid separations. Generator or load tripping may be required to prevent line or equipment overloading. Special breaker tripping or closing schemes such as staggered closing or 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.

10.1.5.5 Telecommunications Requirements for Special Protection or Remedial Action Schemes

The special protection schemes described in this section require telecommunications channels between the RAS controllers and the remote devices. The schemes will require redundant remote devices, redundant channels, and in most cases, geographically diverse communication paths. Specific details for telecommunications channels are in Section 11 Telecommunications Requirements.

10.1.5.6 Remedial Action Scheme Design and Operational Requirements

Minimum requirements for a RAS scheme include the following:

- The RAS should be independent of all other control actions.
- The RAS will have a common architecture as much as possible with existing schemes.
- The RAS will utilize standard alarms to identify operation actions and trouble.
- The RAS scheme must be designed with the ability to safely test the scheme.
- The RAS will be provided with the ability to arm/disarm via SCADA if a SCADA RTU is available.

10.1.5.7 Future Modifications or Revisions to Special Protection or Remedial Action Schemes

Any modification, change, or revision of an installed RAS scheme at a requestor's site must be reviewed by BPA before it is implemented. Proposed changes may also require review by the WECC Remedial Action Scheme Subcommittee.

10.1.6 *Disturbance Monitoring*

Depending upon the type of connection, location, and operating voltage, disturbance monitoring equipment may be required. The monitoring equipment is intended to record system disturbances, identify possible protection scheme problems, and to provide power quality measurements. Sequential event recorders, digital fault recorders, (DFR) and dynamic disturbance recorders may be required. BPA may require remote access to these recorders and relay systems at the POI. Upon request, and if available, BPA will reciprocate by supplying the Requester with limited access to the corresponding equipment at the remote BPA terminals. Refer to section 7.5 for Synchro-phaser (PMU) requirements for generation facilities.

10.1.6.1 Sequential Event Recorders (SER)

A Sequential Event Recorder (SER) time tags and records digital events with one millisecond time resolution. The SER uses a Global Positioning Satellite (GPS) clock receiver for a timing reference. The SER must have sufficient channels to monitor relay and RAS performance, circuit breaker positions, generator status, and other events within the interconnecting substation or generator plant. SERs are required in all 500 kV substations. Generators that are part of a RAS must also have SERs. The SER must have capability for remote communications to connect to BPA's SER master station. At lower voltage substations, multifunction digital relay event recording capability may serve as a possible substitute for a dedicated SER.

10.1.6.2 Digital Fault Recorders (DFR)

The Digital Fault Recorder (DFR) must have sufficient analog channels to monitor critical currents and voltages. The DFR may also include digital channels to monitor selected equipment status in the substation. The DFR must be time synchronized via a GPS satellite clock. A stand-alone DFR is required in 500 kV substations. For lower voltages, it may be acceptable to use multifunction digital relays that have oscillographic capability; if so, the relay must be synchronized to a GPS clock.

11. TELECOMMUNICATION DESIGN

11.1 Introduction

Telecommunications facilities shall be installed to fulfill the control, protection, operation, dispatching, scheduling, and revenue metering requirements. They may be owned by BPA, another utility or a third party. 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 to which the new generation or loads will be connected. Telecommunications facilities will be identified on the Project Requirements Diagram (PRD) and will employ redundant equipment and geographically diverse paths when required by WECC criteria. 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:

11.2 Radio Systems

A radio system requires transmitters, receivers, telecommunication fault alarm equipment, antennas, batteries, chargers, 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. In order to meet power system reliability requirements, radio path diversity, equipment redundancy or route redundancy may be required. These measures protect against telecommunications outages caused by equipment failure or atmospheric conditions. In the vicinity of wind turbines the use of radio systems may be limited because of interference from the turbine blades.

11.3 Fiber Optic Systems

A fiber optic system requires light wave transmitters, receivers, telecommunication fault alarm equipment, multiplex equipment, batteries, chargers, emergency power systems, fiber optic cable (underground or overhead) and rights-of-way. Cable route redundancy may be required in order to prevent telecommunications outages caused by cable breaks.

Customer installations are not to adversely affect the BPA communication system. In particular, the BPA sites on a fiber ring are not to be impacted by an outage or delayed restoration of either customer fiber cable or customer electronics. The following guidelines apply:

- No customer sites are to be added into BPA main rings.
- Subtending rings off BPA nodes to nodes that are owned and/or operated by foreign utilities /other parties are not acceptable. Only non-SONET electrical connections are allowed. SONET overhead is not to be passed between BPA and another entity.

Refer to STD-DT-000088 and STD-DT-000089 for additional design requirements, including those pertaining to fiber cables, demarcation, and vault requirements.

11.4 Wireline Facilities

A wireline facility (e.g., leased line) 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 in order to prevent telecommunications outage. Redundancy of the wireline communications is required when utilized to meet protection requirements per Table 2 or control requirements in Section 10.

11.5 Voice Communications

11.5.1 *Basic Requirements*

If the generation or load facility is within the BPA Control Area and any type of telemetering is required, then voice communications to the operator are also required. Voice communications may be accomplished by the Public Switched Telephone Network (PSTN), or by BPA's DATS (Dial Automatic Telephone System), or by Automatic Ringdown Trunks to each appropriate control center. Any of these are sufficient for facilities 50 MW or less. If the facility is not staffed with operators, alternative arrangements with a scheduling or control agent may be made, subject to BPA approval.

11.5.2 *Automatic Ringdown Trunks*

Dedicated, direct automatic ringdown trunk (or equivalent) voice circuits between each appropriate BPA control center and the operator of the generators or loads may be required for:

- Generators or loads of 50 MW or greater, at continuously staffed locations,
- Eccentric (non-conforming) generators or loads
- Connected networks that include automatic generation tripping for BPA Transmission system remedial action.
- A non-radial interconnection to another electric utility with a transfer capability in either direction of 50 MW or greater.

11.5.3 *Dial Automatic Telephone System – DATS*

The Dial Automatic Telephone Systems' (DATS) primary function is to provide highly reliable voice communication between operational sites for operational purposes (see STD-DC-000040).

Note: An automatic trunk has an advantage if it is important for the Gen plant to also be able to reach BPA Dispatch immediately to report conditions that are not alarmed via a SCADA RTU. This is because the BPA Dispatch DATS number that the plant is asked to call may be busy because the Dispatcher is talking to someone else on that DATS line.

11.5.4 *Independent Communications*

Independent voice communications for coordination of system protection, control and telecommunication maintenance activities between BPA and the generation facility or POI should also be provided.

11.6 Data Communications

Telecommunications for SCADA, RMS and telemetering must function at the full performance level before and after any power system fault condition. Repair personnel must restore service continuity immediately after the fault without the need for intervention. The following requirements for telemetering of data are specified:

11.6.1 *SCADA*

For communication of SCADA information, one or more dedicated circuits are typically required between a new facility and both BPA control center(s).

11.6.2 *Automatic Generator Control (AGC) Interchange & Control Telemetering*

One or more dedicated circuits are typically required between the new generation facility and the appropriate BPA control center(s) for telemetering of AGC Interchange and control information for operations and scheduling applications. If AGC services are required, data will be sent to and from the appropriate BPA control center(s) using the Inter-Control Center Communications Protocol (ICCP) over private control synchronous communication channels operating at a minimum rate of 9600 baud.

11.6.3 *General Telemetering*

General telemetering of power and energy data (in kW, Kvar, kWh) and data acquisition systems typically require one or more dedicated communication circuits. These circuits link the new facility to the master computer receiving the data. Refer to BPA's Revenue and Interchange Metering Application, Standard Number STD-DC-000005, and to Section 13 of this document.

11.6.4 *Revenue Metering System (RMS)*

Commercial dial-up telephone exchange line facilities or functional equivalent are required for support of the MV-90™ compatible remote RMS equipment. The exchange line facilities communicate with the MV-90™ compatible master computer at the Dittmer Control Center. The circuit used for this purpose may also be shared with voice communications and other dial-up data communications. Refer to BPA's Revenue and Interchange Metering Application, Standard Number STD-DC-000005, and to Section 13 of this document.

11.7 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 protection must not be tested, switched, shorted, grounded or changed in any manner by any worker, unless prior arrangements have been made through the BPA dispatcher.

11.7.1 *Application on Main Grid Transmission*

The highest telecommunications performance level as specified by the WECC is 99.95% availability. This level of performance is required on all protection circuits for lines connected to the BPA Main Grid. This performance level is also required for RAS circuits that must meet WECC compliance criteria. These circuits require totally redundant schemes.

Availability is determined for the total path of the protective relaying circuit, from one end of the transmission line to the other. Options for achieving these availability requirements by utilizing two or more separate telecommunication methods, routes or systems may be considered. When alternately routed telecommunications for protective relaying schemes are required, a combination of two of these telecommunications methods may be used to meet availability requirements.

11.7.2 *Speed of Operation*

Throughput operating times of the telecommunications system must not add unnecessary delay to the clearing or operating times of protection or RAS. System studies and WECC trip time requirements determine maximum permissible throughput operating times of control schemes.

11.7.3 *Equipment Compatibility*

Protection systems and supporting telecommunications equipment installed at the interconnecting facility must be functionally compatible or identical to the corresponding equipment employed at the BPA facility. This functionality need not extend to peripherals, such as signal counters and test switches that might be present on BPA's equipment. Teleprotection equipment employed by the Requester must be approved by BPA prior to installation. At the time of the request for interconnection BPA will supply the Requester with a list of acceptable, pre-qualified equipment. Should the Requester choose to employ equipment not on this list, BPA reserves the right to test the equipment for acceptable performance in the required control application. Equipment that passes this testing can be approved by BPA for subsequent installations.

Teleprotection systems, including transfer trip, must be properly designed and tested to demonstrate that they perform their intended functions. When applying digital telecommunications systems to protection schemes, care must be taken ensure equipment compatibility .

11.8 Telecommunications During Emergency Conditions

11.8.1 *Emergency Conditions*

Emergency telecommunications conditions may develop that affect telecommunications equipment with or without directly affecting power transmission system facilities.

Examples of telecommunications emergencies include the following:

- Interruption of power to telecommunications repeater and relay stations
- Telecommunications equipment failure, whether minor or catastrophic
- Interruption or failure of commercial, public switched 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 repair team dedicated to the telecommunications of the interconnecting facility should be retained along with an adequate supply of spare components.

11.8.2 *Backup Equipment*

Where commercial, public telephone network facilities or services support important power system telecommunications, a backup strategy should always be developed by the Requester to protect against interruption of such services. Backup methods could include redundant services, self-healing services, multiple independent routes, 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 also be considered for certain non-critical telecommunications to provide continued operation of telecommunications during interruption of transmission services.

11.8.3 *Disaster Recovery*

The Requester should have a disaster recovery plan in place for telecommunications restoration that should be exercised periodically. The disaster recovery plan should include the ability to provide equipment capable of bypassing or replacing entire telecommunication stations or major apparatus until permanent repairs can be made.

11.8.4 *Telecommunications Security*

The operation of power system telecommunications facilities should be continuously monitored at a central alarm point so that problems can be immediately reported, diagnosed and repaired. Telecommunication sites and facilities should be secured against unauthorized access.

12. COMMISSIONING

12.1 Pre-energization Inspection and Testing

The Requester is responsible for the pre-energization and testing of their equipment.

For equipment that can impact the BPA Grid, the Requester shall develop an Inspection and Test Plan for pre-energization and energization testing. BPA may request to review the test plan prior to the test(s). BPA may require additional tests. The Requester shall make available to BPA, upon request, all drawings, specifications, and test records of the POI equipment. Also upon request BPA will make available to the Requester similar documents describing the BPA POI equipment.

12.1.1 *Installation and Commissioning Test Requirements for Metering*

BPA requires meter testing prior to commissioning. Refer to Section 14.5 and the BPA Metering Application Guide, STD-DC-000005, for additional information.

12.1.2 *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 will determine the type and extent of commissioning tests required. Following are the minimum tests that must be performed on protection schemes at the POI that could affect the BPA Grid.

12.1.2.1 Verify All Protective System Inputs

- Check for proper ratio, polarity, connections, accuracy, and appropriate grounding on current and voltage transformer circuits.
- Verify that shorting of unused current transformer windings is proper and that windings used for protection systems are not shorted.
- Verify that all other inputs to the protection system including battery supplies, circuit breaker auxiliary switches, pilot channel inputs, etc. are correct.

12.1.2.2 Verify Protection System Settings

- Check protection system settings and programming.
- Perform acceptance or calibration tests of the protection system if it was not performed previously.
- Verify that any changes in relay settings required for relay acceptance testing are restored to the desired settings.

12.1.2.3 Protection System Drawings and Wiring

- Verify switchboard panel wiring is intact and matches drawings.

- Verify interconnections between protection system and other devices are intact and match drawings.
- Verify that the drawings are correct.

12.1.2.4 Verify All Protective System Outputs

- Verify that all trip outputs will trip intended trip coil(s).
- Verify that all close outputs will properly close the breaker(s).
- Verify proper relays key the appropriate pilot channel.
- Verify other outputs such as breaker failure initiate, special protection scheme signals, reclose initiate and reclose block, relay alarms, event recorder points, and any other relay outputs to other equipment.

12.1.2.5 Perform Trip or Other Operational Tests

- Assure correct operation of the overall protection systems.
- Test automatic reclosing.

12.1.2.6 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.

12.1.2.7 In Service, Load and Directional Tests

- Measure AC current and/or voltage magnitudes applied to the relay system.
- Measure AC current and/or voltage phase angles applied to the relay system.
- Test the relay system for proper directional operation when applicable.

12.1.2.8 Special Protection Scheme/Remedial Action Scheme Testing

- The RAS must be thoroughly tested prior to energization. This includes an end-to-end test, functional test, or operational tests.
- If the RAS is a part of a WECC compliant RAS, an annual functional or operational test is required.

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 method is acceptable to BPA.

Modifications to a protection system or RAS scheme also requires testing similar to that listed above. The extent of testing and types of tests required depend upon the changes made. Modifications include changes or additions to protection circuits, changes or upgrades of protective relay firmware, and changes in protective relay logic and/or programming. Many utilities also consider it good practice to perform various levels of tests and calibrations following changes in protective relay settings. When making protection system modifications, attention must be paid to any circuits that may be inadvertently affected (e.g.) an auxiliary relay having multiple circuits tied to its outputs.

12.2 Technical Operations Requirements

See Operations Requirements for Generation Interconnection, STD-N-000002.

13. COMMERCIAL OPERATIONS & METERING REQUIREMENTS

13.1 Data Requirements For System Operation And Scheduling

All transmission arrangements for power schedules within, across, into or out of the BPA Balancing Authority Area require metering and telemetering. Some generators or loads that are in another balancing authority area, referred to as a 'host' balancing authority area, also require metering and telemetering to the BPA Balancing Authority Area. Transmission arrangements with loads, generators, or new transmission facilities may include voltage control, and automatic generation control (AGC). The WECC Reliability Coordinator for the region requires data to ensure the reliable operation of the entire grid. The technical plan of service for interconnecting a load, generator, or new transmission facility is shown on the BPA Project Requirements Diagram (PRD) and includes the metering and telemetering equipment consistent with the transmission contract, or balancing authority area services agreement. Such metering and telemetering equipment may include options of being owned, operated, and maintained by BPA or by other parties approved by BPA. See the BPA Metering Application Guide, STD-DC-000005, for more information. Telecommunications requirements for data collection are included in Section 11.

Revenue billing, 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 physically connected to the BPA Grid or electronically connected via telemetering, placing the Project within the BPA Balancing Authority Area.

13.2 Telemetering Data Requirements for BPA Control Centers

BPA requires telemetering data for the integration of new interconnections at adjacent balancing authority area boundaries, as well as new generation within the BPA Balancing Authority Area. This typically consists of the continuous telemetering of active power quantities (in kW) and hourly transmission of the previous hour's energy (in kWh) from the Point Of Interconnection, (POI) to the appropriate BPA Control

Center. Table 5 lists the typical users of metering and telemetering data, and Tables 6 and 7 identify general metering and telemetering requirements for loads and generation. Tables 8 through 11 identify typical additional data requirements.

13.2.1 *Facilities Tied to the BPA Balancing Authority Area Boundary*

Telemetering is required for all normally closed interconnections at a BPA Balancing Authority Area boundary. For this case, telemetering of active power and energy (kW, kWh) is required. There may also be a need for reactive power (Kvar, Kvarh) information for purposes of billing based on power factor. High capacity interconnections may require redundant metering and telemetering.

For connections that are to be normally open, or closed only for emergencies, BPA determines telemetering needs on a case-by-case basis.

Table 5.— Typical Metering & Telemetering Data Usage

System or Quantity	BPA Dispatching and Operations	Transmission Scheduling	Revenue Billing
kW	Yes	No	No[1]
kWh	Yes[5]	Yes	Yes[4]
Kvar	Case-by-case	No	No
Kvarh	Case-by-case[5]	No	Yes
kV	Yes[6]	No	No
Load Size	≥ 3 MW	≥ 1 MW	≥ 1 kW
Date Sample Rate	kW: 1 second or other approved rate compatible with NERC policy	Last hour kWh sent each hour	Hourly kWh data retrieved daily (RMS2 type system)
Tie Capacity	All normally closed ties	All normally closed ties	All ties
AGC	Yes[3]	Yes[3]	No
Generation Reserves	Operating, spinning, regulating, & MW capability	Actuals as delivered	Actuals as delivered

Notes:

1. A kW reading for revenue billing may be required where special transmission arrangements are necessary.
2. Direct Incoming Dial Public Switched Telephone Line or its equivalent required for RMS.
3. All balancing authority area boundaries & customer connections providing ancillary services.
4. Revenue Billing typically receives kWh via the MV-90 system.
5. Electric Industry Data Exchange (EIDE) data link is an alternative to acquire and share kWh and other hourly data between utilities.

6. kV system quantity not required for generation connected to a host utility distribution system at or below 34.5 kV.

Table 6.— Metering, Telemetering and SCADA Data Requirements for Loads (L), Including Station Service, At the Meter Point and Inside BPA Balancing Authority Area

Quanity	L < 1MW	L ≥ 1MW
Billing Information [RMS[3]]; Hourly kWh & Kvarh[2]	Yes If L ≥ 1 kW	Yes
Hourly Estimate of Load (by web, FAX, or phone)	No	Yes[4]
kW Continuous Data	No	No[6]
Loss of Meter Potential Alarm	No	No[6]
Telemetering Equipment Failure Alarm	No	No[6]
Bi-Directional kW & Bi-Directional Kvar Meter[5]	Yes	Yes
kV	No	No[6]
Kvar	No	No[6]
Redundant Meters	No	No[6]

Notes:

1. Hourly estimate of load must equal the sum of transmission schedules for delivered power.
2. Hourly integration of Kvar may be used for reactive billing if Kvarh not available from meters.
3. Direct Incoming Dial Public Switched Telephone Line or its equivalent required for RMS.
4. Required from the scheduling agent to BPA.
5. BPA's standard revenue meter is bi-directional for kW. Refer to BPA's Revenue and Interchange Metering standard for additional details.
6. Required as determined by Technical Operations or Planning studies.

Table 7.— Metering, Telemetering and SCADA Data Requirements for Generation

System or Quanity	G < 3 MW	3 ≤ G < 50 MW [2]	G ≥ 50 MW
Billing Information (RMS)	Yes, if G >200 kW	Yes	Yes
Hourly Estimate of Generation [1] (by web, FAX, or phone)	Conditional[2]	Yes	Yes
Hourly kWh (telemetered)	No	Yes	Yes
kW Continuous Data[10]	No	Yes	Yes
Limit Variable Generation(See Section 13.2.6)	No	Yes[7]	Yes[7]
Loss Of Meter Potential	No	Yes	Yes
MW & Mvar On Each Unit [3]	No	No	Yes If integrated at

System or Quanity	G < 3 MW	3 ≤ G < 50 MW [2]	G ≥ 50 MW
			230 kV or above
Bi-directional kW & Bi-directional Kvar meter[6]	Yes	Yes	Yes
Redundant Meters (A & B)	No	Yes If G > 20 MW	Yes
Gen-ICCP (Redundant Links)	No	No	Yes or via SCADA[8]
kV, Kvar, Circuit Breaker Status	No	Yes[9]	Yes[9]

Notes:

1. Hourly estimate of generation must equal the sum of transmission schedules for marketed power. It is required from the scheduling agent to BPA
2. Hourly estimate is not required if generation is serving local load only. It is required if generation is being used as a marketing resource. Local load is defined as load that is on the generator side of the meter.
3. Separate meters for each unit are required when generators per line are not identical.
4. Required if BPA is the designated scheduling agent.
5. Station service metering is required for all generation, and station service telemetering may be required. See Sections 13.2.3 and 13.2.4.
6. For generating resources with nameplate rating greater than 200 kW and located in the BPA Balancing Authority Area, BPA revenue metering is required. Refer to the BPA Metering Application Guide requirements for Generation Integration Metering. For generating resources 200 kW and less connected to a Host Utility (i.e. not directly connected to the BPA transmission grid), the Host Utility is responsible for the metering requirements.
7. Wind generating plants with aggregate nameplate rating between 3 and 50 MW may use BPA's alternative Wind Limit communications (email and website) until the total wind generation connected to a single BPA POI equals or exceeds 70 MW. See Section 13.2.6.
8. Wind / variable generation may be allowed to use SCADA as determined by BPA. Redundant links required as determined by Technical Operations.
9. If there is an electrical connection to BPA.
10. Continuous kW may be required if the capacity of a BPA-managed WECC path is impacted, even if outside BPA's BA and not connected to BPA's system.

13.2.1.1 Loads Within BPA Balancing Authority Area

For loads with direct electrical connections to the BPA Balancing Authority Area, AGC telemetering is not normally required. For interruptible loads, BPA determines telemetering needs on a case-by-case basis. Significantly large and intermittent loads (e.g. arc furnaces, irrigation pumps, electric draglines) may require an interface to the

BPA 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. Table 6 summarizes metering, telemetering, and SCADA requirements for loads based upon size.

13.2.1.2 Generation Within BPA Balancing Authority Area

For generation connected internal to the BPA Balancing Authority Area, telemetering is required for generation facilities of aggregate output equaling or exceeding three MVA. For this case, telemetering of real power and energy (kW, kWh), and reactive power (Kvar, Kvarh) is normally required. BPA will determine telemetering needs on a case-by-case basis for generation sites that remain below three MVA. Station service load may require separate telemetering if it comes from a different balancing authority area. Table 7 summarizes metering, telemetering and SCADA requirements for generation within the BPA Balancing Authority Area.

Metering and telemetering for temporary generation installations (planned for less than one year of service) will be determined on a case-by-case basis.

Generation sites with an aggregate output equaling or exceeding 50 MVA may require a direct link with BPA via a generation ICCP communication server or SCADA RTU in order to send and receive data directly from the BPA AGC System. ICCP is the Inter-Control Center Communications Protocol, defined by IEC 870-6 TASE.2 standard. See Section 13.2.2.3 for additional details on the ICCP requirements.

WECC requires any generation plant over 200 MVA to have data sent to the Extra High Voltage (EHV) Data Pool. BPA will provide the required data to the EHV Data Pool for any plant over 200 MVA in the BPA Balancing Authority Area unless the generator is a WECC member. In that case, the generator is responsible for reporting to the EHV Data Pool directly or via an agent.

13.2.1.3 Jointly-owned Load or Generation

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 that 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 typically 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 BPA tariffs to properly account for transmission usage. BPA uses the NERC recommended ‘accumulator method’ for accounting, not the ‘rounding method’ for integrated values.

13.2.1.4 Generation in the BPA Balancing Authority Area Not Controlled by BPA

Telemetering is required for generation located internal to the BPA Balancing Authority Area to account for the scheduling that is required to deliver that energy to the appropriate host balancing authority area. The requirements are similar to interchange telemetering requirements. In this case, GenICCP is typically not required by BPA.

13.2.2 *Data Requirements for Balancing Authority Area Services*

The following are the data requirements for balancing authority area services if the requestor wishes to locate a load or generator in the BPA Balancing Authority Area.

13.2.2.1 Requirements for Interconnected Loads

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 generating resources. To the extent that a third party may externally supply regulating or contingency reserve services at the BPA Balancing Authority 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:

13.2.2.1.1 Supplemental AGC Services

If BPA is purchasing supplemental AGC services, AGC interface is required on a long-term basis. Prior to BPA 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 real-time dynamic signals, thus requiring telemetering.

13.2.2.2 Ancillary Services

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 responsible for meeting obligations for necessary ancillary services associated with the interconnection. Most self-provided ancillary services are scheduled and delivered using real-time dynamic signals, which require telemetering. The responsible party may fulfill these obligations in any of the following ways:

- Directly provide ancillary services by making resources available to BPA to deploy
- Contract with a third party to make resources available to BPA to deploy
- Contract with BPA to cover this ancillary services obligation

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 as well as the BPA business practices.

Where a third party is providing ancillary services, the following data is required with a sampling rate established in BPA's business practices – typically four seconds between samples for regulation and ten seconds for operating reserves:

- Net instantaneous active power transferred (in MW)
- Instantaneous reactive power (in Mvar) and total reactive power (Mvarh) transferred
- Operating reserve capability during the upcoming ten minutes
- kWh for most-recent hour
- Area Control Error (Station Control Error for Generating unit)
- Actual Scheduled Interchange

13.2.2.2.1 Supervisory Control and Data Acquisition System (SCADA)

Additional data may be required from loads such as steel rolling mills and wind tunnels, in order to make generation control performance more predictable. Such additional data may include, but not be limited to, precursor signals of expected load changes. SCADA control may also be required. Specific requirements and needs are determined for each load. This may require a separate SCADA remote terminal unit or it may require data be added into an existing SCADA as determined by BPA.

13.2.2.3 Dispatch and Data Requirements for Interconnected Generation

Dispatch and Data requirements for balancing authority area services, such as regulation or operating reserves, apply only to generation resources inside the BPA Balancing Authority Area. For resources that are not part of BPA's Balancing Authority Area, the operator of the Host balancing authority area determines the data requirements.

Inter-Control Center Communication Protocol (ICCP) is a standard communications protocol for data exchange used by BPA and many other entities. ICCP is an international standard for communications of real time data. The IEC 870-6 TASE.2 Standard defines the ICCP. The ICCP protocol is being revised to include certificate authentication and encryption for security purposes. When this package is available, all ICCP servers must be retrofitted. BPA has two systems that communicate via ICCP. The first is GenICCP used for exchanging generation data between the BPA Control Center and the Generation facility. It is an internal, point-to-point service. The second system, called simply ICCP, was previously known as inter-utility data exchange. It is used to exchange SCADA data between BPA and other utilities and balancing authority area operators. This form of data exchange uses public switched telecommunications services, not general internet communications.

For generation resources inside the BPA Balancing Authority Area, Ancillary Services, (e.g. reserves) must be acquired. Provision for all Ancillary Services are specified in the Interconnection Agreement (LGIA or SGIA) or Balancing Authority Area Services Agreement (BAASA). BPA must specifically approve all arrangements for generators intending to provide Ancillary Services to BPA. If the generator is capable of providing Ancillary Services in excess of its obligation, then BPA may choose to contract with the generator operator to provide additional Ancillary Services.

Technical discussions between BPA and generator developers are necessary before the specific implementation requirements can be determined. For generation facilities with a total capacity of 50 MVA or above, GenICCP will generally be required to transmit automated Dispatch instructions and unit status, MW, Mvar and kV from the project, among other data requirements. The AGC data to be passed over the data link may include some or all of the data quantities listed in Tables 8 and 9. For each project a detailed data requirements list with definitions will be provided during the design phase of the interconnection of the project. Actual generator specific data requirements are developed after an Interconnection Agreement or Balancing Authority Area Services Agreement is signed.

All interconnected generation projects are required to implement and maintain automatic voltage control on a voltage schedule provided by BPA Dispatchers. The status and availability of each auxiliary reactive support device is also required. Generation facilities are required to receive automated Dispatch instructions and provide other status and data as needed for the operation of the transmission system.

13.2.2.4 Ancillary Services

If BPA is purchasing ancillary services from the generation facility, AGC control of the generator capability is required on a long-term basis. Prior to purchasing AGC services, a capabilities, cost, and benefit investigation as to the AGC control capabilities of the generation facility is required to determine the specific AGC requirements.

Requirements for Ancillary Services are also driven by how the generator operator or the purchaser chooses to meet the reserve obligations of the generation facility, as described below. Either the generation operator or the entity making the transmission arrangements is liable for the reserve obligations associated with the operation of the generation facility consistent with the BPA Tariff. Generation marketed as interruptible power is treated separately under special provisions and guidelines by the WECC and BPA. The responsible party may fulfill these obligations in any of the following ways:

- Make these reserves available to BPA from the generating facility
- Make these reserves available to BPA from another one of their generation resources
- Contract with another generator operator to make these reserves available to BPA on their behalf
- Contract with BPA to cover this reserve obligation

13.2.2.4.1 Supervisory Control and Data Acquisition (SCADA) Requirements

New substations including those for generation facilities may require BPA SCADA control and status indication of the power circuit breakers and associated isolating switches used to connect with BPA. SCADA indication of real and reactive power flows and voltage levels are also required. If the connection is made directly to a host utility in BPA's Balancing Authority, SCADA control and status indication requirements shall be determined by BPA with consultation with the Host utility on division of responsibilities. SCADA control of breakers and isolating switches that are located at other than the generating facility are not normally required, although status and indication may be necessary for system security purposes. Section 11 discusses telecommunications requirements for SCADA systems.

13.2.2.4.2 GenICCP Installation

A GenICCP installation may be required for generation facilities greater than 50 MVA and is required for generation facilities over 200 MVA. If BPA is not providing any ancillary services, a GenICCP configuration with single server and single router are acceptable. If BPA is providing ancillary services, a primary server and back up server must be installed. If BPA is doing automatic generation control, redundant servers and redundant routers are required. The GenICCP installation at the generating facility provides capability to bring additional data from the generator(s) to the BPA control centers. Table 8 and Table 9 shows the typical GenICCP data required. A GenICCP installation or equivalent SCADA RTU capabilities is required for Variable (VER) generation facilities (Wind) greater than 50 MVA. Table 10 and Table 11 show the typical data and dispatch requirements.

Table 8.— Automatic Generation Control (AGC) Quantities

Generation Plant to BPA Control Center (s):	
1.	Plant in BPA AGC mode/local mode [1]
2.	Net instantaneous power output (MW), unit MW output for plants >200 MW
3.	Plant output attributed to natural governor response (MW)
4.	Plant ramp rate capability – maximum raise and lower
5.	Plant jerk rate capability (rate of change of ramp rate) – maximum raise and lower
6.	Regulating reserve capability - during next 10-minutes
7.	Spinning reserve capability - during next 10-minutes
8.	Operating reserve capability - during next 10-minutes
9.	Maximum capability - normal conditions
10.	Maximum capability - power system emergency conditions
11.	Minimum generation capability
12.	Unit power system stabilizer and automatic voltage regulation status
13.	Unit status - defined below for each generator unit in numerical order. • Out of Service - unit not available for use on 10 minutes notice. • Standby Mode - unit available for use on 10 minutes notice. • Standby Mode - unit available for use within 60 minutes

Generation Plant to BPA Control Center (s):	
	• On-line / Not on AGC • On-line / On AGC • On-line / Condensing
14.	Total Mvar output, unit Mvar output for plants >200 MW
15.	Total instantaneous maximum Mvar capacity boost or each POI voltage level
16.	Total maximum Mvar capacity boost or each POI voltage level
17.	Total instantaneous maximum Mvar capacity buck or each POI voltage level
18.	Total maximum Mvar capacity buck
19.	Plant in BPA kV mode / local kV mode [2]
20.	Acknowledge Limit Wind Generation

Table 9.— Automatic Generation Control (AGC) Quantities

BPA Control Center(s) to Generation Plant:	
1.	Generation request at rated frequency set point - AGC-requested power output level in MW for the following look-ahead time horizons: 0, 5, 10, 15, 20, and 30 minutes.
2.	Generation requested rate of response.
3.	Amount of regulating reserve to carry.
4.	Generation base point - The generation level in MW at which BPA expects to be operating the plant at the end of the ramp.
5.	Plant MW control mode - regulating, base load, standby, or off control
6.	BPA operating mode indication to the plant – normal, assist, emergency
7.	Bus voltage schedule(s) in kV and actual measurement(s)
8.	BPA AGC control center identifier - Dittmer or Munroe Control Center
9.	BPA Mvar Control Mode- coordinated voltage schedule, nominal voltage schedule
10.	Low Reserves Notification
11.	Limit Wind Generation - command
12.	Limit Wind Generation - MW amount

Notes:

1. When plant is in BPA AGC mode, the BPA AGC system is enabled at the plant. The plant is controlling power output to meet the generation request and generation rate of response (MW/minute) originating from BPA. When the plant is in local mode the BPA AGC system is disabled. The plant is not controlling its power output to meet generation request and generation rate of response originating from BPA.

2. When plant is in BPA kV mode, the coordinated var control system is enabled at the plant. The plant is controlling reactive power output to meet the voltage schedule originating from BPA. When the plant is in local kV mode, the BPA coordinated var control system is disabled at the plant but automatic voltage regulators must remain in

service. The plant is controlling its reactive power output to meet the nominal voltage schedule originating from BPA.

Table 10.— Generation Data Requirements for VERs (Wind)

Generation Plant to BPA Control Center(s):	
1.	Net instantaneous power output (MW) (BPA meter point)
2.	Net instantaneous Mvar output (BPA meter point)
3.	Instantaneous Mvar output of each collector line
4.	Instantaneous Mvar output of each reactive element (dynamic and switched)
5.	Voltage of each bus (kV) High side and each collector bus
6.	Available generation capability (MW)[1]
7.	Plant operation limit (MW)[2]
8.	Plant high speed cutout (MW – wind only) (sum of all units out due to high winds)
9.	Automatic voltage control status (on/off), each controller
10.	Automatic voltage mode status (voltage/power factor), each controller
11.	Total plant Mvar capacity boost (Mvar)[3]
12.	Total plant Mvar capacity buck (Mvar)[3]
13.	Status of each generation and reactive element Breaker or switcher
14.	Status of each high side Breaker between generation and BPA system
15.	Acknowledge Limit Wind Generation

Notes:

1. Available generation capability is sum of all units in service available to generate times the MW rated capability of each unit.
2. Plant operational limit is the MW amount the plant is limited to at any time less than the sum of the units available for generation (by BPA Dispatch or plant operator).
3. Total all units in service, available, net at POI.

Table 11.— Generation Control and Data Requirements for VERs

BPA Control Center(s) to Generation Plant:	
1.	Low Reserves Notification
2.	Limit Wind Generation – command (limit level 1, 2, etc)
3.	Limit Wind Generation - MW amount
4.	Bus voltage schedule(s) in kV (future requirement for secondary voltage control)
5.	Dispatch trip control – each generation breaker
6.	Ramp limit initiated (future)
7.	Frequency controller Dispatch initiated (future)

13.2.3 *Generation and Network Interchange Scheduling Requirements*

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

In the case of new transmission facilities, scheduling and accounting procedures are needed if the facility is part of an interface between the BPA Balancing Authority Area and another balancing authority area. This scheduling and accounting of interchange between two balancing authority areas normally requires telemetered data from the POI to the control centers of the balancing authority area operators. This data is termed interchange metering and telemetering by BPA and includes kW and kWh quantities. BPA requires that all balancing authority area transactions be pre-scheduled for each hour using the normal scheduling procedures. The end-of-hour actual interchange must be conveyed each hour to the BPA Control Center(s). This can be accomplished through the use of telemetering or data link.

When the new interconnection represents a shared or jointly owned interface to BPA, or a split resource between the balancing authority area and any other, 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 balancing authority area boundary is an example of this requirement.

13.2.3.1 Generation Metering Requirements

Generation metering usually consists of bi-directional meters and related communications systems providing active power (in kW) and energy (in kWh) from the POI. Active power is telemetered on a continuous basis for AGC and hourly energy is sent each hour to the balancing authority area accounting for BPA. All generation projects of aggregate size equaling or exceeding one MW require hourly pre-scheduling. BPA may also require indication of available spinning reserve and controlled reserves, both in MW.

13.2.3.2 Interchange Metering Requirements

Interchange telemetering consists of bi-directional meters and related telecommunications systems providing kW and kWh at or near the POI. The kW measurement is telemetered on a continuous basis for AGC and hourly kWh is sent each hour to the control center. (Table 7 summarizes the requirements). Interchange telemetering accuracy and calibration requirements are identical with those stated in Section 14.5.

Effective telemetering requires real-time knowledge of the quality of measurement. Associated with the telemetering signal are various indications of this quality. Analog telemetering is commonly accompanied with squelch and telemetering carrier fail alarms. A loss of meter potential or meter potential phase unbalance should trigger a telemetering carrier failure alarm. Digital telemetering has equivalent signal failure alarms. The metering equipment must also be monitored and alarmed in the telemetering signal. Typical alarms include but are not limited to:

- Loss of meter potential
- Loss of telemetering signal
- Loss of meter potential signal

13.2.3.2.1 Generation Parasitic Load, Station Service and Start-Up Metering

BPA requires generation projects to self-supply parasitic loads when generating. When not generating, the generation plant station service load may be served by backfeed over the transmission line that interconnects BPA and the generation plant. Generation plant station service and start-up loads must be properly and accurately metered. At a minimum, bi-directional revenue metering and extended range current transformers are required. In addition, separate dedicated instrument transformers and revenue meters may be required to measure station service and start-up loads. It is preferred to meter generation by locating bi-directional revenue meters and revenue accuracy current transformers such that accurate station service can also be metered. Then metering of net generation, start-up power and station service can be accomplished from a single location. However, if this is not possible, then metering with demand interval data recording (MV90™ compatible) revenue meters and communications is required at the station service transformer(s).

13.2.4 *Revenue and Interchange Metering System*

All facilities capable of exchanging at least 1 kW of active power and directly connected to the BPA transmission grid require BPA qualified metering for revenue and/or interchange Energy data recording is required for BPA's billing and scheduling functions. Revenue metering includes energy (kWh) and reactive power (Kvarh) produced by revenue meters and recorded on a demand interval basis. 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 POI to and from the BPA Grid.

The revenue metering system (RMS) includes a remote metering system to record the hourly kWh data. The hourly kWh data is downloaded from the metering recorder on a daily basis over voice-grade telephone lines. All recorders must be fully compatible with the MV-90™ protocol. Upon request, MV-90, or functional equivalent data is available to the customer or its agent.

13.2.4.1 Requirements for Revenue and Interchange Metering

Refer to BPA's Metering Application Guide, Standard Number STD-DC-000005. Three-element, three-phase, four-wire meters shall be used on grounded power systems. Two-element, three-phase, three-wire meters can be used on balanced, ungrounded power systems. Both revenue metering and interchange metering shall be bi-directional to record both active and reactive power flows to or from the POI. Metering packages include a kWh recording device compatible with the BPA RMS or BPA scheduling system, as applicable.

Tables 6 and 7 identify revenue metering requirements. Section 11.6.4 discusses telecommunications requirements for the RMS system.

13.2.5 *Calibration of Metering, Telemetering, and Data Facilities*

13.2.5.1 Calibration of Revenue and Interchange Metering

Revenue and interchange metering must be calibrated at least every two years. More frequent calibration intervals may be negotiated. All parties to the transmission interconnection agreement may witness the calibration.

13.2.5.2 SCADA and ICCP Data

SCADA and ICCP data shall be calibrated every two years as a minimum or more often if significant errors occur affecting the state estimator results. All parties to the transmission interconnection agreement may witness the calibration.

13.2.6 *Variable Generation Remote Dispatch and Data Requirements*

The requirements below are described with respect to Wind Generation; however, the same rules may apply to Solar Generation. Other types of variable generation sources will be evaluated, with the expectation that these requirements will apply.

13.2.6.1 Limit Wind Generation Output

Wind generation is a variable resource, inherently difficult to forecast. Therefore, all ground-based (on-shore or off-shore) wind generation projects with aggregate nameplate capacity > 3MW within the BPA BAA are required to participate in BPA's "Limit Wind Generation" automated dispatch operational scheme to limit overgeneration and to cut schedules for undergeneration when BPA approaches its Balancing Reserves limit.

For projects with aggregate nameplate capacity between 3 and 50 MW, the designated Generator Operator (GOp) responsible for control of the wind project generation is required to either receive automated email messages and obtain access to BPA's web-based software application, or receive discrete and analog signals via a BPA installed SCADA RTU at the project site. BPA's web-based software application is available to the generation owner and GOp.

Wind generation projects with aggregate nameplate capacity 50 MW and greater, and all wind generation regardless of size that interconnect at a common BPA POI with 70 MW or greater aggregate wind generation shall be required to connect GenICCP at the designated Generation Operator control center or receive discrete and analog signals directly via a BPA installed SCADA RTU at the project site.

Regardless of the communications technology employed, the BPA Dispatcher will issue automated Dispatch instructions to the wind project operator during those times when generation output must be limited, and the project operator will be responsible to limit total plant output to the limit issued by BPA Dispatch. See Section 13.2.3.

13.2.6.2 Wind Generation Controls with Automated Dispatch

New wind projects (starting construction after 6/1/2011) greater than 50 MW are required to have the capability to respond to over-frequency and under-frequency (governor type) control and separate ramp rate control. BPA policies will be developed to address older projects when the need is determined.

As more wind and other forms of variable, non-dispatchable generation connect to the BPA system, the amount of dispatchable generation providing frequency response for system events is reduced. In the future, BPA may need to include wind generation to provide frequency response during system situations where wind is to provide a majority of the generation. This is most likely to occur at high wind-low load times at night. Providing wind generation feathering to reduce over-frequency, or when enabled to feather wind generation in advance to provide an ability to increase generation for an under-frequency event may be warranted as the least cost or preferred option to address this operational issue.

Likewise, wind ramps rates may be necessary as the wind fleet continues to expand to address severe ramps impacting balancing service capability or the AGC generating units. See section 13.2.2.3 for interface requirements. When BPA system conditions warrant, BPA will announce a program to install automated dispatch and work with the wind fleet to implement either of these systems.

13.2.6.3 Wind Generation Forecasting Data Requirements

Wind meteorological generation data is required to forecast the wind fleet impacts on the BPA transmission system and hydro system operations. BPA wind generation forecasting will provide real-time situational awareness for both transmission Dispatch and BPA Hydro Duty Scheduling including unit commitments of the Federal Columbia River Generation System (FCRPS). This will help optimize the river system making it easier for BPA to meet its non-power FCRPS objectives, including flood control, Clean Water Act, and fisheries programs among others. Additional goals are wind ramp predictions, support of smart grid and energy storage.

To support these efforts, BPA has:

- Installed 14 new meteorological sites (6 existing) to support real-time weather observation and share the data with the public.
- Developed an in-house, wind generation forecasting system.
- Is working with commercial wind generation forecasting subscription services.

- Implementing displays and situational awareness tools for operators to track wind generation forecasts and impacts on the transmission systems.
- Will publicly post BPA aggregated fleet level wind generation forecast for wind project and public usage.

13.2.6.3.1 Plant Operational Data

Each wind generation plant should provide the Number of turbines and total rated capacity installed (MW). For each turbine:

- model/type, nameplate capacity
- turbine identification number (string/collector line if available)
- individual turbine coordinates (Latitude/Longitude)

Each wind generation project will be required to provide via BPA telemetry equipment (SCADA RTU or GenICCP) the following:

- Plant output (MW via BPA metering, along with Mvar and kV)
- Available capacity (MW, updated within 10 minutes of any change in the turbine available to generate)
- High wind cutout (MW total)
- Plant control limit (MW, when output of plant is limited)

Planned outages for more than routine turbine maintenance or impacting a significant portion of the plant to be emailed to Gen Dispatcher desk with dates, capacity limitations and duration.

13.2.6.3.2 Plant Meteorological Data via web service

Each wind generation project will provide data from the wind plant's weather anemometers - to be posted or refreshed every minute (one minute averages preferred). Provide anemometer coordinates (Latitude/Longitude/elevation). Data to include:

- Wind speed (mph, integer)
- Wind direction (degrees of north, integer)
- Temperature (degrees F, integer)
- Humidity (relative %, integer)
- Pressure (inches of Mercury, inHg, three significant figures, xx.xxx)

BPA requires designated turbines (one per cluster) Meteorological Data to be provided. BPA will collaborate with the project owner on selection of turbines representative of the clusters (typical cluster will be a five blade diameter square with a center turbine designated) - to be posted or refreshed every ten (10) minutes (ten minute averages preferred). Provide selected turbine number and coordinates (Latitude/Longitude). Data to include:

- Wind speed (mph, integer)
- Wind direction (degrees of north, integer)
- Temperature (degrees F, integer)
- Humidity (relative %, integer)
- Pressure (inches of Mercury, inHg, three significant figures, xx.xxx)

Plant meteorological data is to be posted to a Web service (Business Intelligence tool such as Microsoft Web Services, Windows Communication Foundation, BizTalk or an equivalent tool for Enterprise-level data transfer). The tool cannot be FTP-based. The wind generator must provide a Web Services Description Language (WSDL) to BPA that defines the following:

- The XML schema used to send the data
- Methods that will be used
- Variables/arguments that will be passed in those methods

All wind generators must be vetted through the BPA Cyber Security approval process. Additional BPA requirements for secure communication include:

- The wind generator's web service must have a digital SSL certificate signed by an external 3rd party per industry best practices (ie, Verisign, GeoTrust, etc).
- A password-based or similar means of credential authentication must be employed.
- The service should only allow specific IP addresses on the remote end to pull or push data.

13.2.6.3.3 Historical data (last 2 years, or as available)

Data to include:

- Available Capacity (hourly average)
- Plant meteorological data (10 minute average preferred)
- Anemometer coordinates (Latitude/Longitude/height)
- Wind speed (mph, integer)
- Wind direction (degrees of north, integer)
- Temperature (degrees F, integer)
- Humidity (relative %, integer)
- Pressure (inches of Mercury, in Hg, three significant figures, xx.xxx)

Data is to be emailed to BPA in excel or mutually acceptable format.

13.3 Voltage Schedules

Voltage schedules are necessary, in order to maintain optimal voltage profiles across the transmission system. Optimal profiles minimize transmission of reactive power, and preserve flexibility in use of reactive-power control facilities. To this end, a voltage schedule will be mutually developed between BPA and the Requester, which will be coordinated via time changes developed by the NWPP for such coordination purposes. BPA maintains voltages according to the ANSI Standard C84.1. This allows for variances of ±5% from nominal for all voltage levels except the 500 kV system. The 500 kV system has a nominal voltage of 525 kV with a variance from 500 kV to 550 kV. Equipment connected to the BPA Grid must be compatible with this range of operation. Deviations from the voltage schedule may be ordered by the BPA Dispatcher. Usually the deviations are due to load changes occurring earlier than the NWPP coordinated schedule.

13.4 Reactive Power

Each entity shall provide for its own reactive power requirements, at both leading and lagging power factors unless otherwise specified by BPA. BPA generally requires customers to minimize exchange of reactive power with BPA's system, especially under peak load conditions. This can be accomplished by installing equipment to allow matching of internal supply and demand of reactive power. Closely coupled generators may also receive telemetered voltage schedules or receive the voltage schedule through ICCP to minimize var conflict. (See Section 13.1) Minimizing flow of reactive power on a given line can increase its transfer capability and reduce its losses. Reactive flows at interchange points between control areas should be kept at a minimum.

13.5 Power System Disturbances and Emergency Conditions

13.5.1 *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 not directly tripped due to the disturbance remain in service for dynamic oscillations that are stable and damped.

Large-scale blackouts can result from the excessive loss of generation, outage of a major transmission facility, or rejection of load during a disturbance. In order to prevent such events, under frequency load shedding (UFLS) has been implemented throughout WECC, including the Pacific Northwest. When system frequency declines, discrete blocks of load are automatically interrupted by frequency relays, with most of the interruptions initiated between 59.3 Hz and 58.6 Hz. This load shedding scheme attempts to stabilize the system by balancing the generation and load. It is important that lines and generators remain connected to the transmission system during frequency excursions, both to limit the amount of load shedding required and to help the system avoid a complete collapse. The limited ability of some generators to withstand off-nominal frequency operation has been taken into account in the development of frequency relay setting delays provided in Section 10.

13.5.2 *Voltages During Disturbances*

In order to prevent voltage collapse in certain areas of the Pacific Northwest, undervoltage load shedding (UVLS) 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. The undervoltage relay settings in Section 10 shall coordinate with the undervoltage load shedding program.

13.5.3 *Local Islands*

For those generators interconnected to the BPA Grid through a tapped transmission line, a local island is created when the breakers at the ends of the transmission line open. This leaves the generator and any other loads that also are tapped off this line isolated from the power system. Delayed fault clearing, overvoltage, ferroresonance, extended undervoltages, etc., can result from this local island condition and shall not be allowed to persist. Special relays and relay settings are often required to rapidly disconnect the generator(s) in the local island. See Section 10.1.2.2.4.

13.5.4 *Responsibilities During Emergency Conditions*

Each balancing authority area operator is ultimately responsible for maintaining system frequency within balancing authority area boundaries. All emergency operation involving the BPA transmission system must be coordinated with the BPA Dispatcher. Each party, as appropriate, must participate in any local or regional remedial action schemes. All loads or generators tripped by underfrequency or undervoltage action must not be restored without the balancing authority area operator’s permission. All schedule cuts need to be promptly coordinated with the appropriate balancing authority area operator. All parties have the responsibility for clear communications and to report promptly any suspected problems affecting others.

14. MAINTENANCE

14.1 Outage Planning

The Requestor’s facilities may be part of or connected to key transmission lines that must be kept in service as much as possible. They may be removed from service only after power flow 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, ”Dispatcher/System Operator Handbook” when removing such facilities from and returning them back to service.

The Requester shall not energize any de-energized BPA equipment unless the BPA Dispatcher specifically approves the energization. Where the connection is to a radial load the circuit may be interrupted and reclosed by BPA. In cases where the interconnection taps or breaks an existing BPA line, an auto isolation scheme may be required to maintain service continuity of the BPA line. If the interconnected facilities are networked or looped back to the BPA Grid 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 BPA Dispatcher or as specified in the interconnection agreement.

14.2 Switchable Devices

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

14.3 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. The operator of the Requester's facilities should respond promptly to automatic and forced outages in order to mitigate any impacts on the remaining system, and in a manner that treats all interruptions with the same priority.

14.4 Inspection, Test, Calibration and Maintenance

Transmission elements (e.g. lines, line rights of way, transformers, circuit breakers, control and protection equipment, metering, and telecommunications) that are part of the proposed connection and could affect the reliability of the BPA Grid need to be inspected and maintained in conformance with regional standards. The Requester has full responsibility for the inspection, testing, calibration, and maintenance of their equipment, up to the location of change of ownership or POI. Transmission Maintenance and Inspection Plan (TMIP) requirements are a portion of the WECC Reliability Management System for Transmission. The Requester or utility may be required by WECC to annually certify that it has developed, documented, and implemented an adequate TMIP.

14.4.1 *Summary of the WECC Transmission Maintenance and Inspection Plan (TMIP)*

WECC requires that member utilities prepare a written description of, and update as necessary, its annual TMIP. The TMIP shall provide descriptions of the various maintenance activities, schedules and condition triggers for performing the maintenance, and samples of any checklist, forms, or reports used for maintenance activities. The TMIP may be performance-based, time-based, or both, as may be appropriate. The TMIP shall address each of the following:

- Include the interval schedule (e.g., every two years) for any time-based maintenance activities and a description of conditions that will initiate any performance-based activities.
- Describe the maintenance and inspection methods including specific details for each activity or component listed below.
- Provide any checklists, forms, or reports used for maintenance activities.
- Where appropriate, provide criteria to be used to assess the condition of a transmission facility or component.
- Where appropriate, specify condition assessment criteria and the requisite response to each condition as may be appropriate for each specific type of component or feature of the transmission facilities.

14.4.2 *Transmission Line Maintenance*

The TMIP shall, at a minimum, describe the maintenance practices for all applicable transmission line activities, including the following:

- Patrols and inspections
- Vegetation management and right-of-way maintenance
- Contamination control (e.g. insulator washing)

14.4.3 *Station Maintenance*

The TMIP shall describe the maintenance practices for all applicable station facilities:

- Switchgear, i.e. circuit breakers, circuit switchers, disconnect switches
- Power transformers, shunt reactors, phase-shifting transformers, station service transformers, and instrument transformers
- Reactive devices (including, but not limited to, shunt capacitors, series capacitors, synchronous condensers, series reactors, and current limiting reactors)
- Voltage Regulators
- Protective relay systems and associated communication equipment
- Remedial Action schemes and associated communication equipment

14.4.4 *Maintenance Record Keeping and Reporting*

Maintenance records of all maintenance and inspection activities shall be retained for at least five years. The records of maintenance and inspection activities shall be made available to the WECC or other regulatory body, as requested, to demonstrate compliance with the TMIP. The transmission owner shall maintain and make available on request, records for substantial maintenance or inspection of the items listed above.

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
- Describe the inspection or maintenance that was performed

14.5 Calibration and Maintenance of Revenue and Interchange Metering

Refer to the Bonneville Metering Application Guide, STD-DC-000005. 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 test. Calibration records shall be made available to all interested parties.

Each meter shall be calibrated against a standard or reference instrument or meter that has been calibrated and certified during the preceding twelve months. Calibration of standard meters and instruments must meet accuracy requirements of the National Institute of Standards and Technology.

14.6 Synchronizing

The Requester's system or portion of system with energized generators must synchronize its equipment to the BPA Grid using automatic synchronizers, IEEE Device 25A. Synchronization shall be supervised by a separate synchronizing check relay, IEEE Device 25. The exception to this is under large-scale islanding conditions, where the BPA Dispatcher will re-synchronize the BPA grid to neighboring systems over major interties. Please refer to Sections 10.1.2.2.6 and 10.1.4.2 for specific requirements regarding synchronizing and reclosing.

15. REFERENCES

15.1 Bonneville Power Administration - United States and Other Codes

Accident Prevention Manual (APM)

Transmission System Design Standards, including, but not limited to:

STD-DC-000005, Metering Application Guide (to be Requirements in FY17)

STD-DC-000040, Telecommunications Dial Automatic Telephone System (DATS) Policy

STD-DS-000014, Substation Electrical Clearance and Insulation Policy

STD-DS-000027, Substation Dead-end Tower Loading Criteria

STD-DT-000006, Overhead Cable Selection Standard

STD-DT-000024, Transmission Line Grounding Standard

STD-DT-000052, Transmission Line Disconnect Switch Installation Standard

STD-DT-000062, ROW Width Policy

STD-DT-000064, Transmission Line Lightning Protection

STD-DT-000088, Application Guide for Fiber-Optic Cable Placement and Usage

STD-DT-000089, Fiber-Optic Cable Vault, Enclosure, and Splicing Standard

STD-N-000002, Operations Requirements for Generation Interconnection

STD-N-000003, Breaker Arrangement Application

STD-N-000011, Equipment Ownership Requirements

AGC Requirements Document (BPA)

Balancing Authority Area Services Agreement (BAASA)

http://www.transmission.bpa.gov/business/generation_interconnection/

Large Generation Interconnection Procedure (LGIP) and LGIP Business Practice

Line/Load Interconnection Procedure (LLIP) and LLIP Business Practice

National Environmental Policy Act - 42 U.S.C. & 4321 et seq.

Occupational Safety and Health Administration

Open Access Transmission Tariff – DOE/BPA-3406

Small Generation Interconnection Procedure (SGIP) and SGIP Business Practice

Uniform Building Code

15.2 *ANSI – IEEE – NFPA*

ANSI C84.1 – Electric Power System and Equipment – Voltage Ratings (60 Hz)

ANSI/IEEE Std 421.1 – IEEE Standard Definitions for Excitation Systems for Synchronous Machines

ANSI/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

IEC 870-6 TASE.2 - Inter-Control Center Communication Protocol (ICCP) Standard.

IEEE 100 – The Authoritative Dictionary of IEEE Standards Terms

IEEE 1100 – Recommended Practice for Powering and Grounding Electronic Equipment

IEEE Std – 1159 – Recommended Practice for Monitoring Electric Power Quality

IEEE Std – 1547 – Interconnecting Distributed Resources with Electric Power Systems

IEEE Std - 837 - Standard for Qualifying Permanent Connections Used in Substation Grounding

IEEE Std – C37.118 – Enclosed Field Discharge Circuit Breakers for Rotating Electric Machinery

IEEE Std 367 - Recommended Practice for Determining the Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault

IEEE Std 421.2 – IEEE Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems

IEEE Std 487 - Recommended Practice for the Protection of Wire-Line Communication Facilities Serving Electric Power Stations

IEEE Std 519 - IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

IEEE Std 80 – Guide for Safety in AC Substation Grounding

IEEE Std, C57.116, Guide for Transformers Directly Connected to Generators

NESC C2 - National Electrical Safety Code

NFPA 70 - National Electrical Code