TECHNICAL SPECIFICATIONS

FOR

SMALL GENERATION INTERCONNECTIONS,

EXCLUDING NET METERED AND FERC JURISDICTION FACILITIES

Puget Sound Energy, Inc.

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1. INTRODUCTION

1.1 GENERAL POLICY

The following document is a set of technical requirements for generators, including energy storage, that operate in parallel with PSE's electrical distribution system at voltages at or below 34.5 kV. The intended audience are the engineers responsible for the design and maintenance of the safety and reliability of the electrical distribution system. This document is intended to be comprehensive, however generation and associated technologies, such as microgrid interoperability, electric vehicles, and energy storage, are rapidly evolving. These requirements are subject to change at any time.

For the purposes of this document, "Interconnection Customer" refers to:

1) Any customer-owned generator that does not generate power for sale at wholesale or for transmission in interstate commerce, and

2) Is not subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC), and

3) Is connected to PSE distribution voltage level (34.5kV or below).

The following describes what remains outside the scope of this document:

1) Net Metering – Refer to Schedule 150.

2) Transfer Switches – Refer to Sch. 80 and see section 4.7 for more details.

"PSE" means Puget Sound Energy, Inc..

The requirements stated in this document are intended to minimize adverse conditions on the PSE system and to enable the Interconnection Customer to operate its generating equipment in parallel with PSE's system in a safe and reliable manner. The requirements cover the necessary interconnection equipment (relays, breaker, etc.) to be installed, owned, and maintained by the Interconnection Customer. The interconnection equipment is required to disconnect the parallel generation from the system whenever a fault or abnormality occurs. PSE will identify any additional enhancements needed on the PSE system to provide the capacity and protection systems needed to successfully integrate the generation into the system. **PSE's interconnection requirements are designed and intended to protect PSE's system only**. The Interconnection Customer is solely responsible for protecting its generation and interconnection equipment. It is emphasized that these requirements are general and may not cover all details in specific cases. **Interconnection Customers are advised to discuss project plans with PSE before purchasing or installing any equipment**. Any equipment not approved for installation may cause additional review and delays in acquiring a Certificate of Completion.

If the Interconnection Customer should cause harmonics, voltage fluctuation, or other system issues with PSE's system or PSE's other customers, then PSE shall have the right to require the Interconnection Customer to install suitable equipment to reasonably correct or limit such abnormalities at no expense to PSE or PSE's other customers. PSE retains the right to disconnect the Interconnection Customer's equipment until system issues are resolved.

1.2 COMPLIANCE WITH PSE TARIFFS

Interconnection Customers shall comply with the applicable requirements in these PSE Tariffs:

- Schedule 80 – General Rules and Provisions
- Schedule 150 – Net Metering Services for Customer Generator Systems
- Schedule 152 – Interconnection With Electric Generators

1.3 RESPONSIBILITY AND LIABILITY

The Interconnection Customer shall submit in a timely manner sufficient design and specifications information relating to the facilities to be installed by the Interconnection Customer and PSE shall be entitled to review and approve said facilities prior to their installation and energization. The Interconnection Customer agrees to incorporate any design changes requested by PSE prior to, during, or after installation of Customer's facilities. PSE's approval of any design and specification information related to the facilities to be installed by the Interconnection Customer shall not be construed as an endorsement of such engineering plans, specifications or other information.

1.4 <u>TERMS & DEFINITIONS</u>

1 **"Affected Systems"** means an electric system other than Company's Transmission System that may be affected by the proposed interconnection.

2 **"Application"** means the written notice, as defined in WAC 480-108-030, which the interconnection customer provides to the electrical company to start the interconnection process, as defined in WAC 480-108-010.

3 **"Business day"** means Monday through Friday excluding official federal and state holidays, as defined in WAC 480-108-010.

4 **"Certificate of completion"** means the form, described in WAC 480-108-050(2), which must be completed by the interconnection customer's electrical inspector and approved by the electrical company indicating completion of installation and inspection of the interconnection, as defined in WAC 480-108-010.

5 **"Distributed Generation (DG)"** means all generation sources, including batteries and renewables, connected to The Company's distribution system (equal to or less than 34.5kV). Sometimes referred to as Distributed Energy Resources.

6 **"Electric system"** means all electrical wires, equipment, and other facilities owned by the electrical company used to transmit electricity to customers, as defined in WAC 480-108-010.

7 **"Area Electric Power System (Area EPS)"** means an Electric Power System that serves Local Electric Power Systems as defined in IEEE 1547 Section 3.1.

8 **"Local Electric Power System (Local EPS)"** means an EPS contained entirely within a single premises or group of premises as defined in IEEE 1547 Section 3.1.

9 **"Electrical company"** means any service company, as defined by RCW 80.04.010, engaged in the generation, distribution, sale, or furnishing of electricity and subject to the jurisdiction of the commission, as defined in WAC 480-108-010.

10 **"Feeder Section"** means the portion of the Area EPS from the location of the installation to the nearest upstream three-phase protective device (Recloser or Circuit Breaker).

11 **"Generating facility"** means a source of electricity owned, or whose electrical output is owned, by the interconnection customer that is located on the interconnection customer's side of the point of interconnection, and all associated facilities, including interconnection facilities, which the interconnection customer requests to interconnect to the electric system, as defined in WAC 480-108-010.

12 **"Group Study (Clustering)"** means the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection System Impact Study.

13 **"Initial operation"** means the first time the generating facility operates in parallel with the electric system, as defined in WAC 480-108-010.

14 **"Intentional Island"** means planned electrical island that is capable of being energized by one or more local EPSs. These (1) have DER(s) and load, (2) have the ability to disconnect from and to parallel with the area EPS, (3) include one or more local EPS(s), and (4) are intentionally planned, as defined in IEEE 1547 Section 3.1.

15 **"Interconnection"** means the physical connection of a generating facility to the electric system so that parallel operation may occur, as defined in WAC 480-108-010.

16 **"Interconnection Agreement"** means an agreement between an electrical company and the interconnection customer which outlines the interconnection requirements, costs and billing agreements, insurance requirements, and ongoing inspection, maintenance, and operational requirements, as defined in WAC 480-108-010.

17 **"Interconnection customer"** means the person, corporation, partnership, government agency, or other entity that proposes to interconnect, or has executed an interconnection agreement with the electrical company, as defined in WAC 480-108-010.
The interconnection customer must:

(a) Own a generating facility interconnected to the electric system; or

(b) Be a customer-generator of net-metered facilities, as defined in RCW 80.60.010(2); or

(c) Otherwise be authorized to interconnect by law.

18 **"Interconnection facilities"** means the electrical wires, switches and other equipment owned by the electrical company or the interconnection customer and used to interconnect a generating facility to the electric system. Interconnection facilities are located between the generating facility and the Point of Interconnection, as defined in WAC 480-108-010.

19 **"Island"** means a condition in which a portion of an Area EPS is energized solely by one or more Local EPSs through the associated POIs while that portion of the Area EPS is electrically separated from the rest of the Area EPS on all phases to which the DER is connected. When an island exists, the DER energizing the island may be said to be "islanding," as defined in IEEE 1547 Section 3.1.

20 **"Minor modification"** means a physical modification to the electric system with a cost of no more than ten thousand dollars, as defined in WAC 480-108-010.

21 **"Nameplate capacity"** means the manufacturer's aggregate output capacity of the generating facility. For a system that uses an inverter to change DC energy supplied to an AC quantity, the nameplate capacity will be the manufacturer's AC output rating for the inverter(s). Nameplate capacities shall be measured in the units of kilovolt amperes (kVA), as defined in WAC 480-108-010. **<u>Alternate Definition:</u>** Nominal voltage (V), current (A), maximum active power (kW), apparent power (kVA), and reactive power (kvar) at which a DER is capable of sustained operation, as defined in IEEE 1547 Section 3.1.

22 **"Net metering (≤100kVA),"** as defined in RCW 80.60.010, means measuring the difference between the electricity supplied by an electrical company and the electricity generated by a generating facility that is fed back to the electrical company over the applicable billing period, as defined in WAC 480-108-010.

23 **"Parallel operation"** or **"operate in parallel"** means the synchronized operation of a generating facility while interconnected with an electric system, as defined in WAC 480-108-010.

24 **"Reference Point of Applicability or RPA"** means the location where the interconnection and interoperability performance requirements specified in this standard apply as defined in IEEE 1547 Section 3.1.

25 **"Point of Change of Ownership" or "POCO"** the point where ownership of the electrical facilities changes from the Interconnection Customer to the Company. The POCO may be at a unique point or be the same as the PCC or POI as described in Schedule 152.

26 **"Point of Delivery" or "POD"** – the point of the system where the load is half the size of the generator.

27 **"Point of Interconnection" or "POI" –** the point where the Interconnection Facilities connect to the Company distribution facilities that are shared with all other of the Company's Customers and the cost of which is paid by all of the Company's Customers. This is typically the point where the equipment designed to interrupt, separate or disconnect the Generating Facility from the Company's Electric System as described in Schedule 152. PSE defines POI as

equivalent to Point of Common Coupling (PCC), as defined in WAC 480-108-010 and IEEE 1547 Section 3.1.

28 **“Point of Metering” or “POM” –** the location of the meter base owned by the Interconnection Customer. The POM may be at the POI or the POCO, but does not define either the POI or POCO as described in Schedule 152.

29 **"System upgrades"** means the additions, modifications and upgrades to the electric system at or beyond the point of interconnection necessary to interconnect the generating facility, as defined in WAC 480-108-010. System upgrades do not include interconnection facilities.

1.5 GUIDING PRINCIPLES

In the process of completing interconnection studies and developing interconnection requirements, PSE’s technical focus is on meeting the following guiding principles.

1. **Provide interconnection requirements that do not reduce reliability to existing customers or sensitivity to detect/clear faults on PSE’s system.**
2. **Maintain coordination of existing protection equipment.**
3. **Maintain protective device clearing speed within acceptable limits.**
4. **Prevent unintentional islanding of existing PSE customers.**
5. **Ensure that faults on the customer’s system are isolated by customer’s equipment.**
6. **Replace single phase devices with three phase devices for larger facilities.**
7. **Provide redundancy of protective devices for larger facilities.**
8. **Ensure that fault interrupting duty of distribution equipment is not exceeded.**
9. **Provide visibility at the point of interconnection for system operations and event analysis purposes for larger facilities.**
10. **Load flow, power quality, and other general service requirements must be maintained as specified in Schedule 80.**
11. **If the generation exceeds the minimum load on a substation, the impacts on the transmission system shall be studied via a separate Transmission System Impact Study.**

1.6 CUSTOMER APPLICATION REQUIREMENTS

Note: In order to avoid any unnecessary costs associated with changes to the preliminary design plans, this preliminary design package should be approved prior to the Interconnection Customer ordering any equipment, or beginning any major detailed engineering consultant work.

The Interconnection Customer initially submits a preliminary design package to PSE in the PowerClerk portal for review and approval. This package shall include:

- A preliminary proposed electrical one-line diagram that identifies basic service voltages, manufacturer's name, and equipment rating. See example figure 1.6.1.
- Major facility equipment and ratings, such as generators (gross and net), Generating Facility address, transformers, breakers, or approximate load/station service requirements.)
- Metering and Point of Interconnection voltage.
- Any pertinent information on normal operating modes, proposed in-service dates (both Initial Operation and commercial operation).
- A Site plan including:
  - Satellite imaging background (such as Google earth, Bing maps, etc.).
  - Existing and proposed roadways for vehicle access.
  - Existing utility equipment and proposed point of interconnection.
  - Existing and proposed structures.
  - Applicable parcel lines, easements, and setbacks.
  - Applicable water ways, railroads and other notable obstructions.
  - Accurate engineer or architecture scale.
  - An arrow depicting true north.

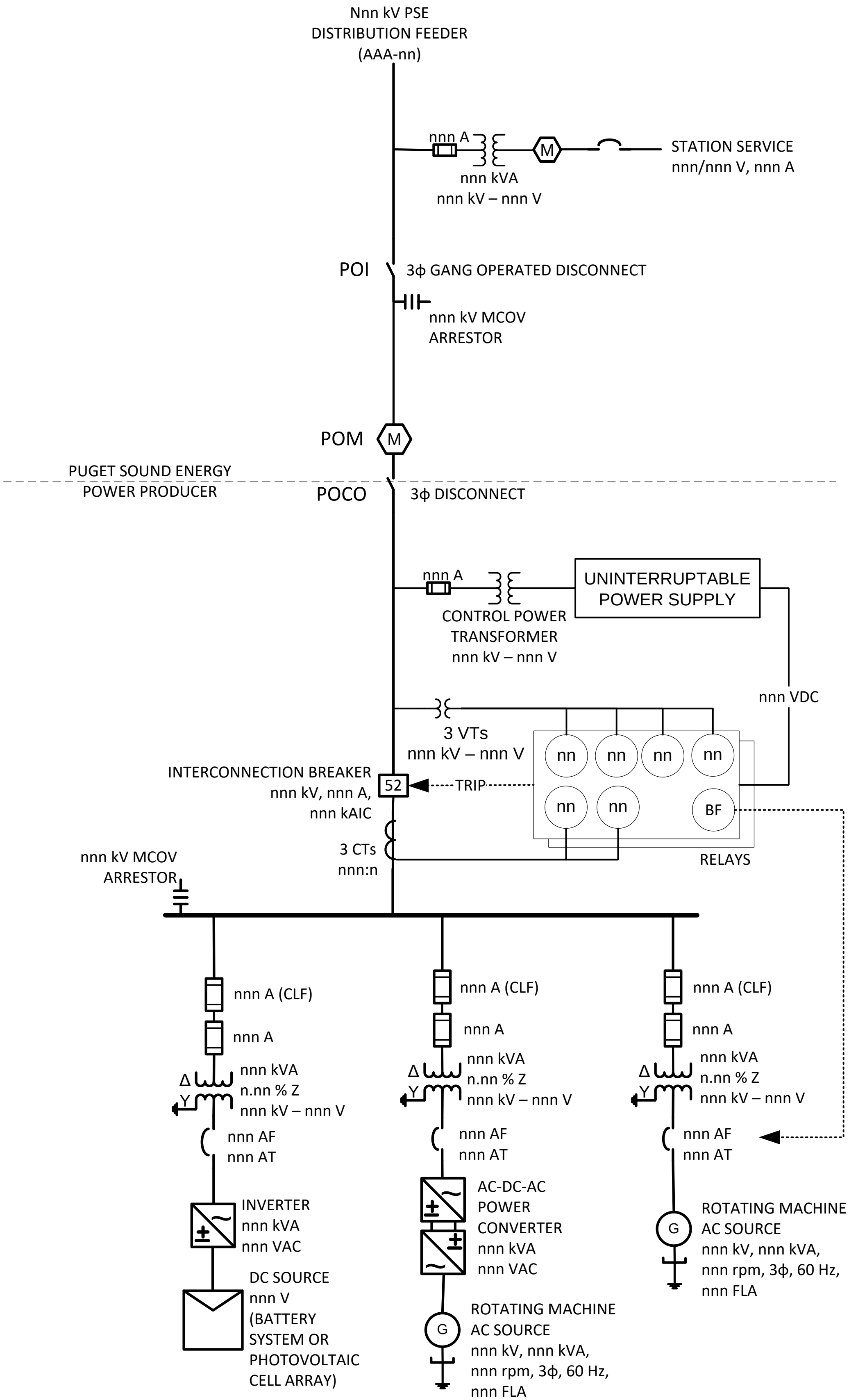


Figure 1.6.1 – Example One Line Diagram

1.7 STUDY PHASES

1.7.1 Tier’s per Schedule 152

- PSE may provide reduced level of interconnection studies for Tier 1, 2 and 3 equipment based on the complexity of the installation. See Schedule 152 for additional details on the interconnection requirements for Tier 1, 2 and 3.

1.7.1.1 Tier 1

- The purpose of the protection requirements for Tier 1 is to prevent unintentional islanding and ensure the inverter output is disconnected when PSE’s electric system is de-energized.

- Tier 1 applies to inverter based systems listed and labeled with UL 1741. The maximum size of the system is 25 kVA. It must be single phase and operate at secondary voltage (600 Volt class).

- Tier 1 systems require an interrupting device capable of safely interrupting the maximum available fault current near the point of interconnection.

- The installation must require no construction or upgrades to PSE facilities other than meter changes.

- Tier 1 applications may not be allowed based on the pre-existing aggregate generation on a segment or line. See Schedule 152 for details on these limitations.

- Tier 1 systems are protected by a controller certified to UL 1741 without additional protective relays. The customer owned generator controller must also meet Schedule 80 service requirements.

- See Section 5.4.1 for typical interconnection requirements.

1.7.1.2 Tier 2

- The purpose of the protection requirements for Tier 2 is to prevent islanding and ensure the inverter output is disconnected when PSE's electric system is de-energized. The generator will also be prevented from automatically reconnecting to PSE.

- Facilities that meet all the requirements of Tier 1, other than the construction upgrade requirements, may be reviewed for Tier 2.

- Tier 2 applies to inverter based systems.

- The maximum size of the facility to qualify for Tier 2 is 500 kVA.

- Tier 2 systems can be connected at voltages at or below 38 kV class (34.5kV nominal system voltage).

- Tier 2 systems require an interrupting device capable of safely interrupting the maximum available fault current near the point of interconnection.

- Tier 2 applications may be rejected based on the pre-existing aggregate generation on a segment. See Schedule 152 for details on these limitations.

- Inverter based system that qualify for Tier 2 and are protected by a controller certified to UL 1741 may be approved without additional protective relays. The customer owned generator controller must also meet Schedule 80 service requirements.

- See Section 5.4.2 for typical interconnection requirements.

1.7.1.3 Tier 3

- Tier 3 includes inverter based systems over 500 kVA and all rotating machines.
- See Section 5.4.3 for typical interconnection requirements.

1.7.2 Interconnection Studies

The electrical company may require a feasibility, system impact, facilities, or other studies as described in WAC 480-108-030(10)(c). These studies are intended to quantify the impacts of the generating facility on the electric system, and may include an analysis of power flow, stability, metering, relay/protection, and communications/telemetry. Acceptance of the results of these studies by the interconnection customer is a condition of approval of the application because the studies provide the basis for the detailed technical requirements for interconnection.

1.7.2.1 Preliminary Site Assessment (Optional)

There is an option to have PSE provide an overview of the distribution system at the Customers chosen site. This preliminary site assessment requires a Google type map showing at least two named roadways, and 8760 hourly estimate of generation output, and the intended Point of Interconnection. Some of the items included in the site assessment study include:

- Project Name.
- Site Address.
- Generator Nameplate Rating.
- Power and Communications Availability to Site.
- Substation and circuit proposed facility will connect to.
- Circuit distance between substation and site.
- Special site conditions (such as river crossings, etc.).
- Minimum load for substation and circuit.
- Nearest alternate substation and circuit.
- Existing aggregate generation on the circuit.

1.7.2.2 Feasibility Study (FS)

The feasibility study is used to determine if a project is developed enough to evaluate the system impact. It is generally required if there are high risk or high cost issues associated with the interconnection. The study will help PSE and the customer to understand all the potential complications associated with the project that may affect the decision to move forward in the interconnection process. This study will likely focus mostly on site control (permitting, easement, right of way, railroad, highway, and river crossings, etc.) and a very basic level of electrical issues between the proposed POI and the substation. The System Impact Study (SIS) will provide more detail related to the interconnection's impacts to PSE's electric system.

The Electric System distribution planner, with input from the project team, is responsible for determining whether a feasibility study is necessary and the content of the study. A feasibility study will result in a report outlining high level cost estimates, major obstacles, timelines and permitting issues. The following guidelines should help with determining whether a feasibility study is necessary:

- If the generator is greater than or equal to 2 MW, the interconnection will trigger a feasibility study and SCADA will be required.
- Generators less than 2 MW may also require a feasibility study based on a variety of factors as identified in Feasibility Study agreement.

1.7.2.3 System Impact Study (SIS)

An SIS outlines the requirements necessary for the distributed generation to be connected to PSE's system.

An SIS will result in a report outlining the interconnection requirements, configuration alternatives and cost estimates.

System Impact Study (SIS) Outline

1. Title Page
2. Table of Contents
3. Introduction
4. Existing facilities
5. System Improvements
6. Interconnection Requirements
7. System Protection
8. Communication Requirements
9. Metering Requirements
10. Operational Requirements
11. Interconnection Transformer
12. Short circuit analysis
13. Load Flow Analysis
14. Avian Requirements (if required)
15. Future System Modifications
16. Test Plan and Witness test / Commissioning
17. SIS Assumptions
18. Summary of Customer's Conceptual Estimated Interconnection Costs

1.7.2.4 Facilities Study

The primary author of the Facilities Study is the Project Manager. The Facilities Study is a refinement of the SIS addressing:

1. Construction Schedule with dates vetted by Program Management and all engineering groups
    a. Addressing potential construction and storm season impacts
    b. Long lead time item ordering implications
2. Address Financial Surety documentation which substantiates the developers credit worthiness for full cost of construction
3. Will a mobile sub be required and available during construction
4. Refinement of all permitting issues
    a. Will a pull out for a PSE bucket truck be required to access overhead lines
    b. Detailed final one line diagram with a Professional Electrical Engineer (registered in the state of Washington) stamp and plot plan showing exact locations of pad or pole mounted equipment (survey preferred)
    c. Rail Road, River, State and County Highway crossings addressed
    d. Determination of the impact on the transmission system (if any) and potential mitigation. This may involve 3rd parties and may impact study delivery date and interconnect agreement
5. Refined Cost Estimate

1.8 Construction Phase (Final Design and Implementation)

When the customer chooses to implement the generation interconnection the following steps are required:

- PSE prepares Construction Agreement and sends to customer.
- Customer submits signed Agreement.
- PSE creates Construction Work Order to accept deposit and begin work.
- Customer submits 50% of the estimated cost defined in Facilities Study as a deposit for construction activities.
- Customer submits Financial Surety documentation from financial institution funding project.
- Customer and PSE address long lead time equipment ordering (some equipment can take 6 months or more).
- PSE Confirms availability of line crews (service provider), substation, communications, and relay techs.
- Final Construction Design Process – typically two design meetings with entire team before ‘Design Issued for Construction’.
- PSE and Customer review and adjust construction schedule.
- Concurrent construction activities by both parties.
- Substation and Controls Commissioning (Communication, SCADA, RTU etc.).
- Witness testing (See section 9).
- Customer completes Certificate of Completion and attaches Labor and Industries (L&I) sign off on electrical inspection.
- PSE signs Certificate of Completion and notifies Customer they are approved to operate (Customer shall not generate in Parallel Operation prior to this).

2 PSE SYSTEM INFORMATION

2.1 VOLTAGE

PSE's most common primary local distribution voltage is 12.47 kV. Other local distribution voltages are sometimes used in specific areas (example 4.16 kV or 34.5 kV). The majority of the distribution circuits are "effectively grounded" (see *Section 2.3*) and are used for four-wire (phase to neutral) connected loads. The Interconnection Study will determine the voltage at the Point of Interconnection.

2.2 FREQUENCY

The frequency for connection to the PSE's system must be 60 Hz nominal sinusoidal alternating current at a standard voltage (see *Section 2.1*) and phase rotation.

2.3 PSE EFFECTIVE GROUNDING

PSE maintains effective grounding on its distribution systems as defined by IEEE Std. 142, 4.12 and 7.4. See Section 4.5 for Effective Grounding requirements.

3. SYSTEM INTEGRITY

3.1 GENERAL

The interconnection of the Interconnection Customer's generating equipment with the PSE system must not cause any reduction in the quality of service being provided to PSE's other customers. No abnormal voltages, frequencies, or interruptions will be permitted. If high or low voltage issues, transient voltage issues, and/or harmonic (voltage distortion) issues result from operation of the Interconnection Customer's generation, such generating equipment shall be disconnected from PSE's system until the problem is resolved by the Interconnection Customer. The Interconnection Customer is responsible for the expense of keeping their electrical equipment in good working order so that the voltage, total harmonic distortion, flicker, power factor, and VAR requirements are always met.

3.2 HARMONICS

The Total Harmonic Distortion (THD) from the Generating Facility will be measured at the Generating Facility's metering point or Point of Interconnection. Harmonics on the power system from all sources must be kept to a minimum. Under no circumstances will the harmonic current and voltage flicker be greater than the values listed in *Tables 1, 2, 3 and 4* from the most current version of IEEE Std. 519. PSE to measure harmonic contribution prior to first energization and post installation.

Note: Any interference with customers or communications caused by the Interconnection Customer's harmonics in excess of federal, state, or local codes will be resolved at the Interconnection Customer's expense.

3.3 VOLTAGE - DISTRIBUTION LEVEL

The Interconnection Customer shall ensure that operation of its generator(s) does not adversely affect the voltage stability of PSE's system as described in section 3.3 and 3.4. Adequate voltage control shall be provided by all Interconnection Customers to minimize voltage deviations on the PSE system caused by changing generator loading conditions.

The Interconnection Customer's generator(s) shall be capable at all times of continuous operation at 0.95 to 1.05 per unit voltage, as measured at the Point of Interconnection. The Interconnection Customer's generator(s) shall not cause the voltage as measured at the Point of Interconnection to be less than 0.95 or to exceed 1.05 per unit voltage. Steady state voltage variation shall not exceed 8% of the standard voltage, measuring from upper to lower variation within a period of one minute. The Interconnection Customer's generator(s) shall be capable during electric system disturbances of short term operation at voltages (as measured at the Point of Interconnection), and for durations as provided in the most current version of the NERC/WECC Planning Standards, Section I.A, WECC Disturbance-Performance Table.

3.3.1 Power Factor Requirement at POI

PSE would prefer a target power factor value of 1.0 or unity power factor unless specified otherwise. Automatic power factor or VAR controllers must be provided for installations utilizing synchronous generators. Generator installations over 5 kVA must maintain power factor as directed by PSE between 0.95 bucking or leading (VARS into the generator) and 0.95 boosting or lagging (VARS out of the generator), inclusive, over an operating range of 25% to 100% of maximum rated power during all hours of operation. These power factor requirements are to be met at the Point of Interconnection, *during all hours of operation and overall operating conditions*.

The *Net* Boosting or Lagging Power Factor Requirement at POI: The Interconnection Customer's generator(s) shall be designed to be able to operate in such a manner as to provide and deliver, at the Point of Interconnection, for voltage or power factor requested by PSE operators, enough VAR output to obtain a ***net*** 0.95 power factor boosting or lagging (VARS are supplied to PSE's system by the Generating Facility) minimum at the maximum rated (MW) generator capacity.

The *Net* Bucking or Leading Power Factor Requirement at POI: Additionally, the Interconnection Customer's generator(s) shall be designed to be able to operate in such a manner as to provide and deliver, at the Point of Interconnection, for voltages or power factor requested by PSE operators, enough VAR absorption to obtain a ***net*** 0.95 power factor bucking or leading (VARS are absorbed from PSE's system by the Generating Facility) minimum at the maximum rated (MW) generator capacity.

Notes: the Point of Interconnection is often not the same as the generator terminals, and typically the generator must have capability to operate at a power factor that is lower than 0.95 boosting. For example, if the Point of Interconnection is the high side of the generator step-up transformer the generator must provide the sum of transformer VARS plus 0.95 boosting at the Point of Interconnection.

3.3.2 Reactive Power Capability

For synchronous generators, sufficient generator reactive power capability shall be provided to withstand normal voltage changes on the PSE system. The generator voltage-VAR schedule, voltage regulator, and transformer ratings (including taps if applicable) will be jointly determined by PSE and the Interconnection Customer to ensure proper coordination of voltages and regulator action.

For induction generators, where starting will have an adverse impact on PSE system voltage, step-switched capacitors or other techniques may be required to limit the voltage changes and bring the unit to synchronous speed before connection to PSE.

3.3.3 Voltage Flicker

The magnitude and frequency of the voltage flicker (i.e., sudden momentary voltage change) caused by the Interconnection Customer shall not exceed the values given in the most current version of PSE's Standard Practice 0650.4100, "Voltage Flicker" (see *Figure 3.3*). Voltage flicker percentage shall be referenced to generator pre-synchronize or motor pre-start conditions. Some PSE customers have voltage sensitive loads and, if PSE receives complaints from customers affected by the Interconnection Customer, the Interconnection Customer will be responsible for reducing voltage variations even if they are within the parameters stated in the voltage flicker chart in the above referenced PSE Voltage Flicker standard.

Voltage flicker will normally be measured at the Point of Interconnection between the Interconnection Customer and PSE. However, at PSE's discretion, if voltage flicker problems are found, the measurement may be taken at the nearest possible present or future PSE customer.

The voltage flicker chart does not address the time duration of the voltage drop. For the purposes of this section, a drop of any duration shall be considered as a single occurrence. Such a voltage drop may be acceptable after consultation with PSE, but the Interconnection Customer is responsible for any associated damage caused to the equipment or lost productivity of other PSE customers. It is advised that Interconnection Customers review the most current version of IEEE Standard 141 (Red Book) for typical sensitivity to very short voltage disturbances.

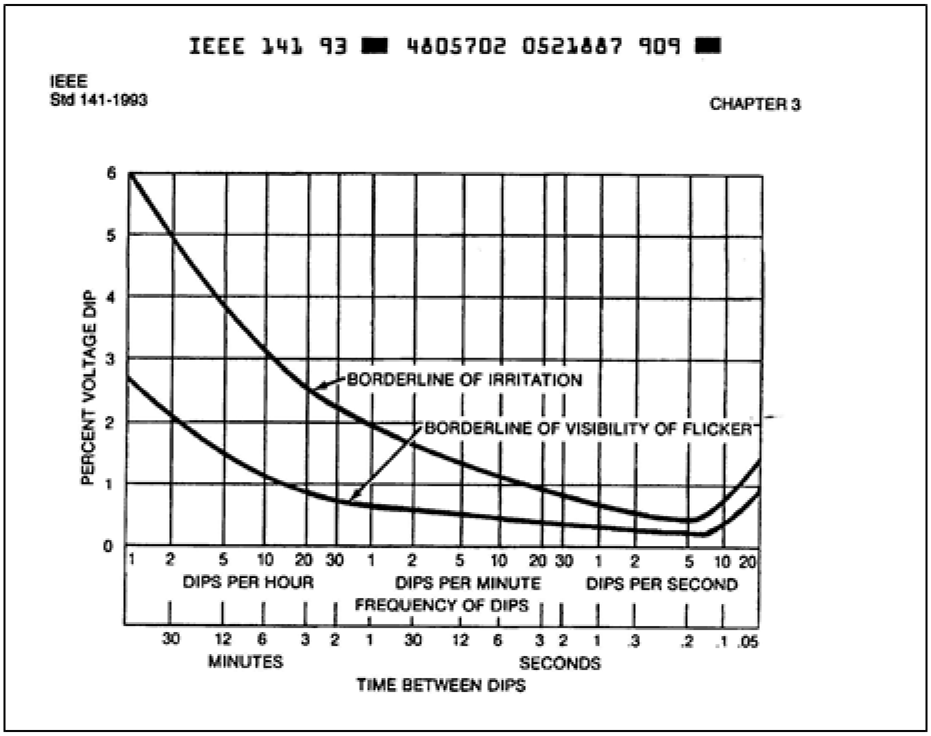


Figure 3.3 Range of observable and objectionable voltage flicker versus time, from PSE Standard 0650.4100

3.3.4 Induction Generators

Under certain conditions, a self-excited induction generator can produce abnormally high voltages that can cause damage to the equipment of other Interconnection Customers and other customers. Overvoltage relays can limit the duration of such overvoltage events, but cannot control their magnitude. Because of these problems, the reactive power supply for large induction generators must be studied on an individual basis. In general, self-excitation problems are most likely in rural areas where the PSE system capacity and load density are low. Where self-excitation problems appear likely, special service arrangements will be required.

3.4 INVERTER BASED RESOURCE VOLTAGE REQUIREMENTS

Inverter based resources must meet PSE standard voltage requirements.

4. GENERAL DESIGN REQUIREMENTS

4.1 CODES

The Interconnection Customer's installation must be in compliance with all applicable laws, regulations, codes, and jurisdictional requirements.

4.2 DISCONNECTING DEVICES

For all generation interties greater than 5 kVA, a disconnecting device (normally a disconnect switch) is required at the Point of Interconnection that separates the Interconnection Customer's Generating Facility from PSE's system. The switch must be operable by PSE, must be accessible to PSE at all times, and must be lockable in the open position with PSE's standard padlock with a visible break over 600V. For three-phase installations, gang-operated three-pole switches must be installed. Each switch or other disconnecting device shall comply with the most current versions of PSE Standard. If the switch is located on the PSE side of the Point of Interconnection, it shall be installed by PSE at the Interconnection Customer's expense. If the switch is located on the Interconnection Customer's side, it shall be installed by the Interconnection Customer. Any interconnection breaker shall comply with the most current version of PSE Standards.

4.3 INTERRUPTING DEVICES

Any interrupting device installed by the Interconnection Customer must be adequately rated for interrupting the available short circuit current. PSE will provide short-circuit data to the customer for use in calculating the required interrupting rating as part of the System Impact Study. PSE shall review and accept customer interrupting device prior to project installation.

4.4 CONTROL REQUIREMENTS

Outputs or interposing relays controlled by programmable logic controls shall not be in series with the interconnection tripping relays and breaker trip coils. All interconnection protection relays shall be capable of tripping the breakers.

All Tier 3 interconnection protection systems shall be powered by station battery DC voltage and must include a DC undervoltage detection device and alarm. The station battery design shall be in compliance with the most current version of IEEE Std. 485. The station battery design shall be reviewed and accepted by PSE prior to project installation.

4.5 EFFECTIVE GROUNDING

It is the Interconnection Customer's responsibility to ensure that its system is effectively grounded at the Point of Interconnection. As defined by IEEE Std. 142, an effectively grounded system requires that $X0/X1 < 3$ and $R0/X1 < 1$ and $X2 < 2*X1$. In general, PSE does not allow grounding banks (wye grounded – delta transformer connections) on distribution systems. Customer transformer connections will be evaluated in the System Impact Study.

In lieu of meeting the requirements above, inverters that comply with IEEE 1547 Section 7.4 and equipped with step up transformers where X0 <= X1 are considered compliant with PSE effective grounding requirement.

The customer shall provide documentation, certifications, and calculations to PSE to show compliance with this requirement for review and acceptance by PSE prior to project installation.

4.6 LOAD REJECTION

If generation system is unable to meet IEEE 1547 Section 7.4 at no load, then PSE will perform detailed studies to determine system requirements.

4.7 GENERATORS CONNECTED THROUGH A CLOSED-TRANSITION TRANSFER SWITCH

Certain installations, such as demand reducing units (sometimes referred to as "peak shaving" units, where the local demand is reduced), or emergency backup generation, may operate in parallel with PSE's system for some period of time. Although no power is intentionally shipped to PSE and no power is purchased by PSE, faults that occur on PSE's system while the generation is operating in parallel will be subject to fault contributions from the generator.

An Interconnection Agreement *is not* required for the following:

- For installations with an aggregate capacity of 25 kVA or less. The installation must comply with the requirements of PSE's Schedule 150.
- For installations up to 20 MVA of generation, paralleled to PSE's system through an automatic transfer switch that is designed to have the systems in parallel for less than 500 milliseconds. However, written approval outlining the Interconnection Customer's liability is required per Schedule 80.

An Interconnection Agreement *is* required for either of the following instance:

- Installations with an aggregate capacity greater than 25 kVA of generation that is designed to operate in parallel with PSE's system for 500 milliseconds or longer.

Note: When an Interconnection Agreement is required, the interconnection requirements in this document will apply. If the Interconnection Customer's system has a transfer switch of the open transition type (break-before-make) at the Point of Interconnection, the switch must be approved in advance by PSE.

4.8 PRODUCTION CONTROL

Developers must provide detailed technical data for the generation system to be installed. PSE reserves the right at any point to specify production ramp rate and production control based on current and future system constraints, as outlined in the interconnection agreement.

5. ENGINEERING AND PROTECTION INTERCONNECTION REQUIREMENTS

5.1 GENERAL REQUIREMENTS

- To ensure that all proposed interconnections are handled uniformly, this section outlines the minimum protection requirements for the interconnection to protect PSE's system.
- PSE reserves the right to require additional protection beyond that specified here necessary to preserve the integrity of the PSE System. Each generator interconnect request will be studied individually to identify protection requirements specific to the project, as well as required network upgrades resulting from the project.
- PSE studies will look at the existing generation on a circuit as well as any new generation proposed. If the new generation will cause the circuit or substation to exceed one of the limits, the owners of the new generation will be responsible for any additional upgrades or other modifications required to comply with this document.
- Project design shall include redundancy and backup protection for larger units, in accordance with Good Utility Practice. When required, relay redundancy may be provided by multiple single function relays or redundant multifunction relays.
- Relays not equipped with an internal isolation device must be connected through an external test device such as an ABB FT-1 switch or equivalent.
- PSE reserves the right to reject relays if there is insufficient documentation to show the relay meet the application requirements or do not meet the requirements of C37.90.
- Drawing attachments show typical arrangements for equipment. The review process will determine the actual requirements for a project. Those requirements will be based on specific generator equipment arrangement and PSE equipment as shown on the project one line diagram.
- The review process may determine transfer trip is required. PSE will determine the communication channel and power producer may be required change relaying to accommodate transfer trip.
- If lightning arresters are installed at PSE distribution voltage, they must be rated as indicated by PSE. Protection of the generators is the responsibility of the power producer.
- PSE may review settings, or specify features such as breaker fail that must be incorporated.

5.2 METHODOLOGY FOR STUDYING DISTRIBUTION GENERATION IMPACTS AND LIMITS

The purpose of this section is to describe a methodology for studying system impacts due to the interconnection of distributed generation (DG) on the feeder system. Tools such as Synergi and ASPEN will be used to simulate power system conditions which will be studied

to meet the intent of this document. The details related to using these tools are not included in this section.
Following are details related to the process for studying distribution generation impacts and limits:

- Where required, a Feasibility Study (FS) is completed to identify if there is high risk or high cost associated with the interconnection. In general, FS is required for generation over 2 MW, generation located in remote areas at the edge of the distribution system, or where there are other system challenges. See Section 1.7.2.2 for additional details.
- Performing a System Impact Study (SIS) following the receipt of a completed application(s) will allow PSE to identify the larger system impacts with high level system improvement cost estimates in a timely manner for the customer(s)
- Once the system impacts are identified by the SIS, the customer will decide whether to move forward with the project by completing a Facilities Study, which will concentrate on specific impacts, cost estimates, and an implementation schedule for their individual facility
- When multiple facilities are proposed on the same feeder or substation by one or more customers, a Group Study will be done with impacts identified for specific proposals by specific site locations. The resulting system impacts will be summarized so that each customer proposal is clearly associated with its contribution to the overall list of impacts and associated cost estimates for system improvements. See Section 5.2.3 for details on the Group Study process.

The following is a sample list of factors that will be considered for feeder and substation level studies:

5.2.1 Feeder Level Study

- Evaluate each proposed facility in the order of its application queue, identifying any resulting impact at each specific site location and associated system improvements.
- For each shared feeder (combination of PSE customers and DG customers), the aggregate sum of existing non-net metered DG plus the proposed facility(s) will be modelled
- The aggregate feeder sum cannot exceed the existing conductor/cable ratings for overhead conductors and underground cable. Actual allowable feeder limits for DG may be less than the feeder rating as determined by site locations and the impact study results. The study will identify the limiting element of a circuit to determine the capacity rating for a DG installation at each specific site.
- If the collection of aggregate DG, existing and proposed, exceeds the feeder capacity, then a dedicated circuit may be required.
- If existing infrastructure is insufficient for proposed generation, alternative solutions to increase system capacity will be provided by PSE.

5.2.2 Substation Level Study

- The substation level impacts should be studied using the aggregate sum of non-net metered DG facilities (existing and proposed) on all feeders fed from the substation
- The aggregate substation sum cannot exceed the existing substation transformer forced cooled rating for continuous loading. In the case of large DG facilities which require transfer trip islanding protection, PSE may add controls to these schemes which will disconnect this DG in the event that transformer forced cooling equipment fails to operate. Actual allowable substation limits for DG may be less than the substation rating as determined by the impact study results.
- DG above the existing substation transformer capacity would require a system improvement project to add capacity or transmission level of service.

5.2.3 Group Study Documentation

- A standard SIS level study format has been created by PSE. For each Group Study (cluster study) where multiple requests have been received at the feeder level, substation level, or both, the System Impact Study will determine capacity limitations and any associated system improvement requirements for the feeders and substation transformer.
- The cost of performing the SIS evaluation may be shared by multiple customers if the timing of the proposals enable a Group Study to be the timely option. Individual DG proposals will have unique impacts, and should be studied in the order that the completed applications were received.
- Resulting impacts and associated system improvements will either be grouped as "common" to all proposals, or specified as unique to a proposal.
- Each customer will be notified of required upgrades and associated cost estimates for system improvements, respective of where they are in the queue.

5.3 GENERAL SYSTEM REQUIREMENTS

- In all cases, the interconnection equipment must isolate the Generating Facility from the PSE system when power is disconnected from its PSE source, including but not limited to, before any reclosing (automatic or manual) takes place. The Interconnection Customer shall prevent its generation equipment from automatically re-energizing the PSE system.

- For all generation added to the PSE distribution system, the total symmetrical three-phase fault current shall not exceed 10,000 amps RMS and the total symmetrical single-phase-to-ground fault current shall not exceed 7,100 amps RMS anywhere on the distribution circuit where the generation is connected. This total includes the existing PSE system, all existing aggregate generation as calculated by PSE and the proposed new generation.

- Inverter based systems are extremely limited in the current they can produce under fault conditions. Typically this fault current is in the range of 120 percent of rated current. Fuses and overcurrent relaying may not be able to react to faults fed solely from the inverters. Because of this limitation, protection must be based on voltage and frequency deviations.

- Typically PSE will review current and potential transformer arrangements and ratings as part of the review process. PSE will require 3 voltage transformers in a Wye –Wye arrangement for voltage protection functions at PSE distribution voltage level.

5.4 TYPICAL INTERCONNECTION REQUIREMENTS

Table 5.1 Summary of Interconnection One-Line Diagrams

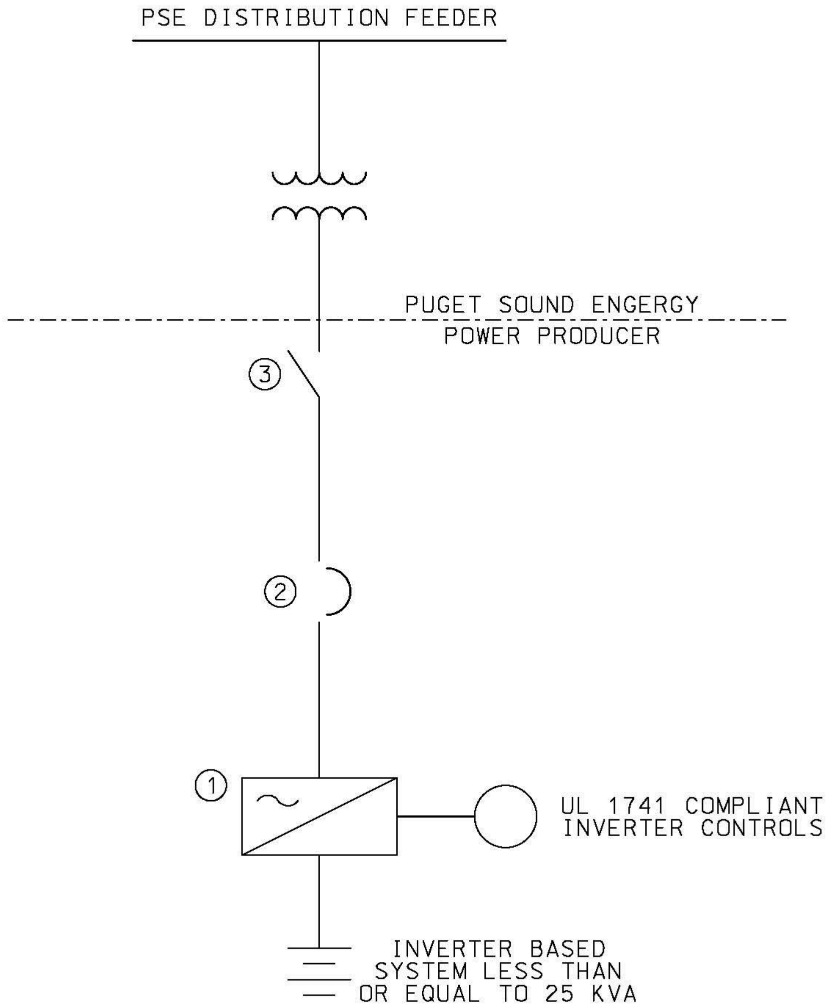
For AGGREGATE Generation Capacity:	See:
Tier 1 - Inverter Based Systems Less Than or Equal to 25 kVA	Drawing 90101
Tier 2 - Inverter Based Systems Greater Than 25 kVA but Less Than or Equal to 500 kVA	Drawing 90201
Tier 3 - Inverter Based Systems Greater Than 500 kVA but Less Than or Equal to 5 MVA	Drawing 90301
Tier 2 - Non Inverter Based Systems Less Than or Equal to 500 kVA	Drawing 90401
Tier 3 – Non Inverter Based Systems Greater Than 500 kVA but Less Than or Equal to 5 MVA	Drawings 90501 & 90502
Metering - Option A	Drawing 90701
Metering - Option B	Drawing 90801

NOTE: AGGREGATE generation includes all existing and proposed generation.

5.4.1 Tier 1 - Distributed Generation less than or equal to 25 kVA

- Generators Less than or equal to 25 kVA may be approved based on internal generator packages. PSE must still review and approve the protection and isolation capabilities of the system. Protective breaker must be capable of interrupting the current at the point of interconnection.
- Note: All Generating Facilities to provide overcurrent protection as required by the Authority Having Jurisdiction.
- See Attachment 90101 below.

Tier 1 - Inverter Based Systems Less Than or Equal to 25 kVA



1. SYSTEM IS SINGLE PHASE
2. SYSTEM CONNECTS AT LESS THAN 600V
3. CUSTOMER PROVIDED DISCONNECT OR METER BASE

INTERCONNECT REQUIREMENTS
TIER 1 - INVERTER BASED
GENERATOR SYSTEM LESS THAN OR EQUAL 25 KVA

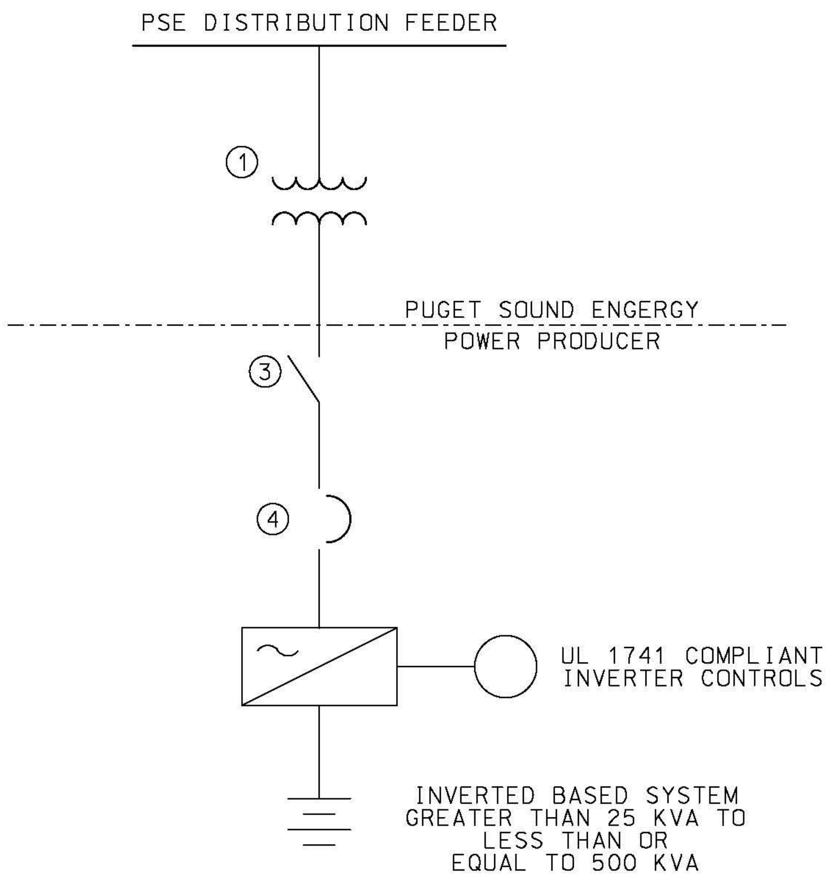
REVISION DESCRIPTION:			TESTED BY			DATE	/ /		PUGET SOUND ENERGY	SUBSTATION ENGINEERING DEPARTMENT	
DESIGNED	P. TIBBITS	2021-12-17	CADD			APPROVED			DRAWING NO	SHEET NO	REV NO
DRAWN	M. POPRAVAK	2021-12-17	CHECKED			FILED			000901	01	01

5.4.2 Tier 2 - Distributed Generation Greater than 25 kVA and less than or equal to 500 kVA

- Connection to the PSE system shall be through a service transformer that is not used to serve other customers for all Generating Facilities greater than 25 kVA, unless otherwise approved by PSE.
- The interconnection protection shall be utility grade, and shall conform to the most current version of ANSI Standard C37.90 for all non-inverter technology greater than 25 kVA. Frequency relays must be solid-state or microprocessor technology.
- All Generating Facilities greater than 50 kVA may require three-phase connections.

  Further studies will be required to determine if a single-phase connection is allowed for installations greater than 50 kVA.
- If generation less than or equal to 500 kVA connects to PSE's system through an inverter or static power converter whose controller is certified to UL 1741 and IEEE 1547, then no further protection within customer facilities is required by PSE.
- Protection is required at the point of interconnection for non-UL 1741 certified inverter and non-inverter based installations.
- A single microprocessor-based relay is typically used with an alarm on relay fail that will automatically isolate the generation from the PSE system. These systems may be protected by a single breaker.
- Note: All Generating Facilities to provide overcurrent protection as required by the AHJ.
- See Attachments 90201 and 90401 below.

Tier 2 - Inverter Based Systems Greater Than 25 kVA but Less Than or Equal to 500 kVA

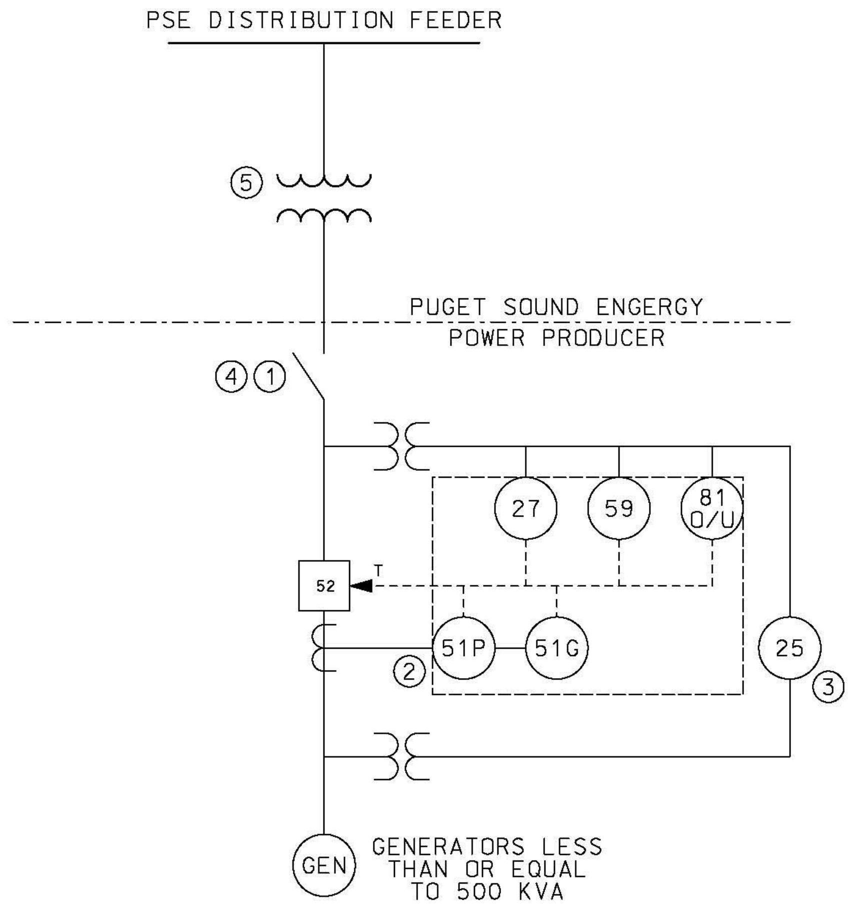


1. DEDICATED SERVICE TRANSFORMER REQUIRED
2. GENERATOR SYSTEM OVER 50 KVA MAY REQUIRE 3 PHASE CONNECTION
3. CUSTOMER PROVIDED DISCONNECT SWITCH
   GANG OPERATED SWITCH REQUIRED FOR 3 PHASE CONNECTIONS
2. PROTECTION AT POI AS REQUIRED BY THE AUTHORITY HAVING JURISDICTION (AHJ)

INTERCONNECT REQUIREMENTS
TIER 2 – INVERTER BASED
GENERATOR SYSTEM GREATER THAN 25 KVA TO LESS THAN OR EQUAL TO 500 KVA

REVISION DESCRIPTION:			TESTED BY			DATE	/ /		PUGET SOUND ENERGY	SUBSTATION ENGINEERING DEPARTMENT	
DESIGNED	P. TIBBITS	2021-12-17	CADD			APPROVED			DRAWING NO	SHEET NO	REV NO
DRAWN	M. POPRAVAK	2021-12-17	CHECKED			FILED			000902	01	01

Tier 2 - Non Inverter Based Systems Less Than or Equal to 500 kVA



1. GANG OPERATED DISCONNECT SWITCH
2. PHASE AND GROUND OVERCURRENT PROTECTION MAY BE REQUIRED DEPENDING ON PSE SYSTEM PROTECTION ANALYSIS
3. SYNCH CHECK REQUIRED FOR SYNCHRONOUS GENERATOR
4. ALL GENERATORS GREATER THAN 50 KVA MAY REQUIRE 3 PHASE CONNECTION
5. DEDICATED SERVICE TRANSFORMER MAY BE REQUIRED FOR GENERATORS GREATER THAN 25 KVA

INTERCONNECT REQUIREMENTS
TIER 2 - NON INVERTER BASED
GENERATOR SYSTEMS LESS THAN OR EQUAL TO 500 KVA

REVISION DESCRIPTION:			TESTED BY			DATE	/ /	PUGET SOUND ENERGY	SUBSTATION ENGINEERING DEPARTMENT	
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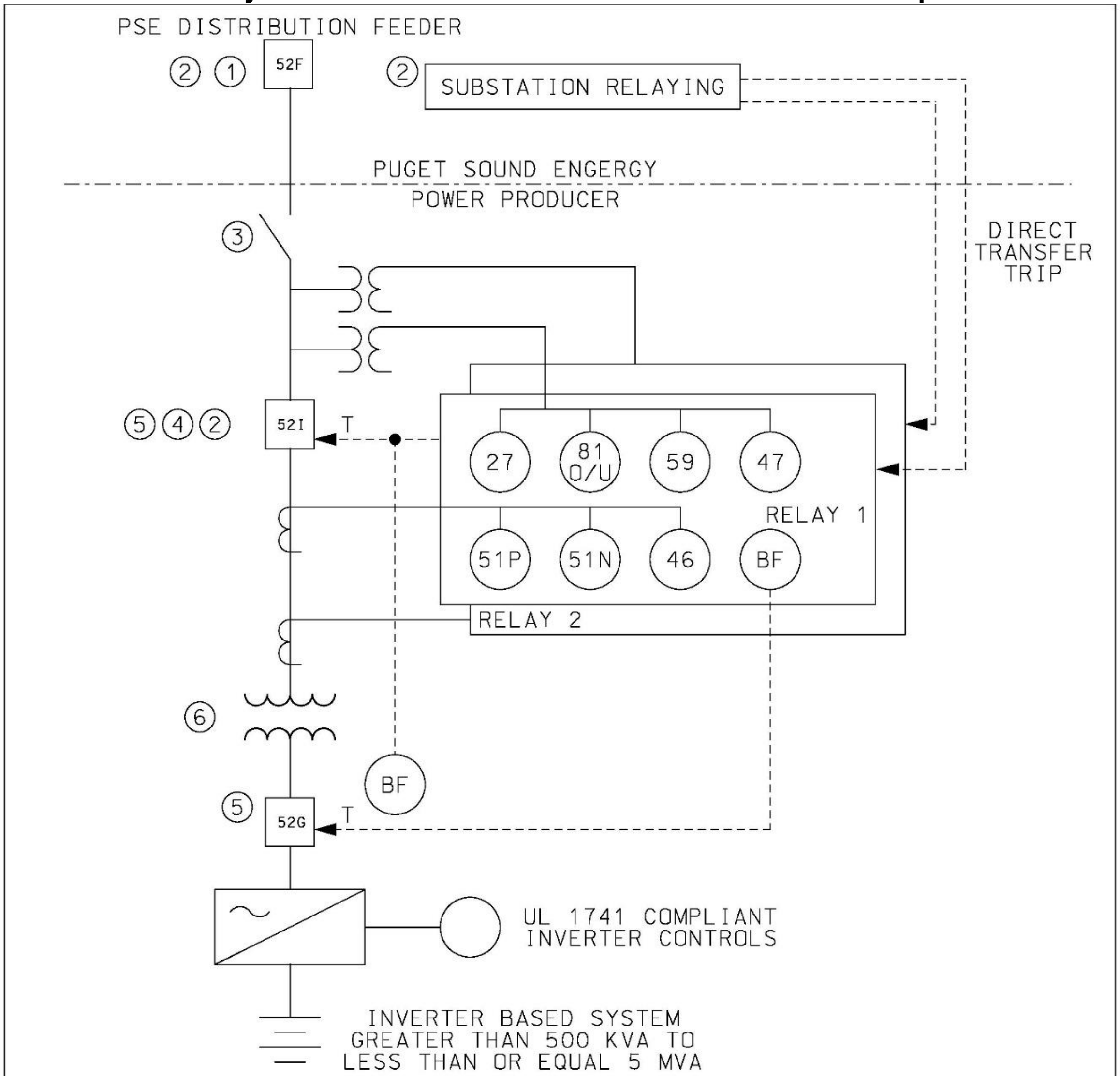
DRAWN	M. POPRAVAK	2021-12-17	CHECKED			FILED		000904	01	01

5.4.3 Tier 3 - Distributed Generation Greater than 500 kVA and less than or equal to 5 MVA

- For units larger than 500 kVA the design of the interconnection protection shall be based upon a philosophy that no single failure will compromise the ability to disconnect a generator from the PSE utility system. Redundant relays and breakers and instrument transformers will be required.
- Microprocessor relays provide event recording. Event recording is strongly recommended for all Generating Facilities greater than 500 kVA and may later be required if needed for unresolved operational or fault events.
- PSE will specify the interconnect transformer connections for projects greater than 500 kVA.
- Overcurrent protection, breaker failure detection, and tripping are all initiated by the customer generator on all generation greater than 500 kVA. Failure of the interconnection breaker must initiate secondary action to isolate the generation from PSE's system. This usually requires two generator breakers or a generator breaker and a main breaker.
- If adequate sensitivity of interconnection relays is not achievable with aggregated generation, individual relaying will be required on each generator.
- See Attachments 90301, 90501 and 90502 below.

Tier 3 - Inverter Based Systems Greater Than 500 kVA but Less Than or Equal to 5 MVA

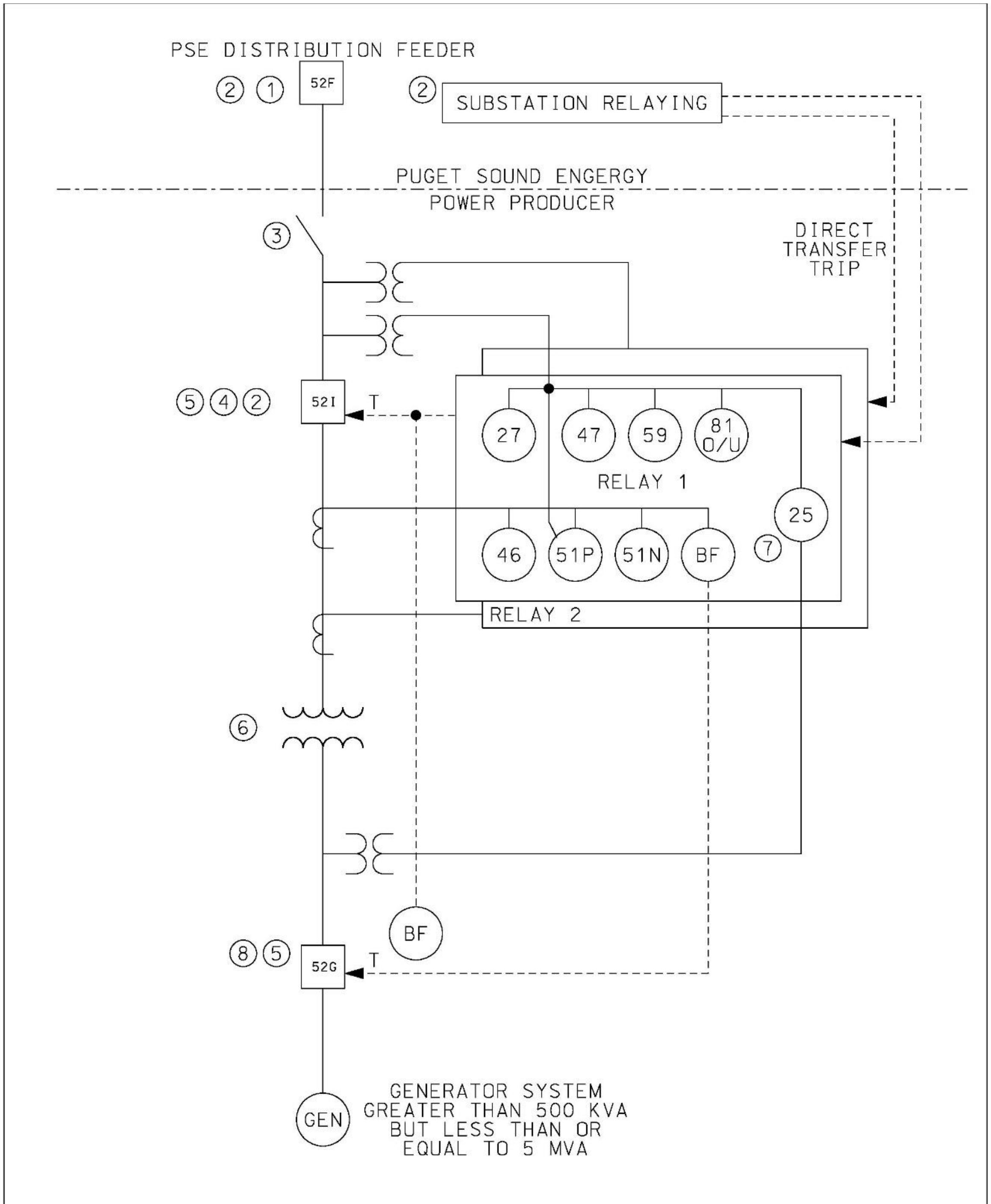


1. PSE FEEDER BREAKER AT SUBSTATION
2. DIRECT TRANSFER TRIP FROM PSE SUBSTATION TO 52I MAY BE REQUIRED
3. GANG OPERATED DISCONNECT SWITCH
4. REDUNDANT RELAYING AND INSTRUMENT TRANSFORMERS REQUIRED
5. REDUNDANT BREAKERS REQUIRED WITH BREAKER FAIL.
   BF FOR 52I TRIPS 52G, BF FOR 52G TRIPS 52I
6. PSE TO SPECIFY INTERCONNECTING TRANSFORMER CONNECTION FOR GENERATORS GREATER THAN 1 MVA

INTERCONNECT REQUIREMENTS
TIER 3 – INVERTER SYSTEM
GENERATING SYSTEMS, GREATER THAN 500 KVA BUT LESS THAN, OR EQUAL TO 5MVA

REVISION DESCRIPTION:			TESTED BY			DATE	/ /		PUGET SOUND ENERGY	SUBSTATION ENGINEERING DEPARTMENT	
DESIGNED	P. TIBBITS	2016-08-30	CADD			APPROVED			DRAWING NO	SHEET NO	REV NO
DRAWN	P. FARBER	2016-08-30	CHECKED			FILED			000903	01	00

Tier 3 – Non Inverter Based Systems Greater Than 500 kVA but Less Than or Equal to 5 MVA



INTERCONNECT REQUIREMENTS
TIER 3 – NON INVERTER BASED
GENERATOR SYSTEM GREATER THAN 500 KVA BUT LESS THAN OR EQUAL TO 5 MVA

REVISION DESCRIPTION:			TESTED BY			DATE	/ /		PSE PUGET SOUND ENERGY — SUBSTATION ENGINEERING DEPARTMENT
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DRAWN	P. FARBER	2016-08-30	CHECKED			FILED			000905 / 01 / 00

(1) PSE FEEDER BREAKER AT SUBSTATION

(2) DIRECT TRANSFER TRIP FROM PSE SUBSTATION TO 52I MAY BE REQUIRED

(3) GANG OPERATED DISCONNECT SWITCH

(4) REDUNDANT RELAYING AND INSTRUMENT TRANSFORMERS REQUIRED

(5) REDUNDANT BREAKERS REQUIRED WITH BREAKER FAIL.
BF FOR 52I TRIPS 52G, BF FOR 52G TRIPS 52I

(6) PSE TO SPECIFY INTERCONECT TRANSFORMER CONNECTION FOR GENERATORS GREATER THAN 1 MVA

(7) SYNCH CHECK REQUIRED FOR SYNCHRONOUS GENERATORS

(8) GENERATOR PROTECTION NOT SPECIFIED

INTERCONNECT REQUIREMENTS
TIER 3 - NON INVERTER BASED
GENERATOR SYSTEM GREATER THAN 500 KVA BUT LESS THAN OR EQUAL TO 5 MVA

REVISION DESCRIPTION:			TESTED BY			DATE	/ /		PUGET SOUND ENERGY	SUBSTATION ENGINEERING DEPARTMENT	
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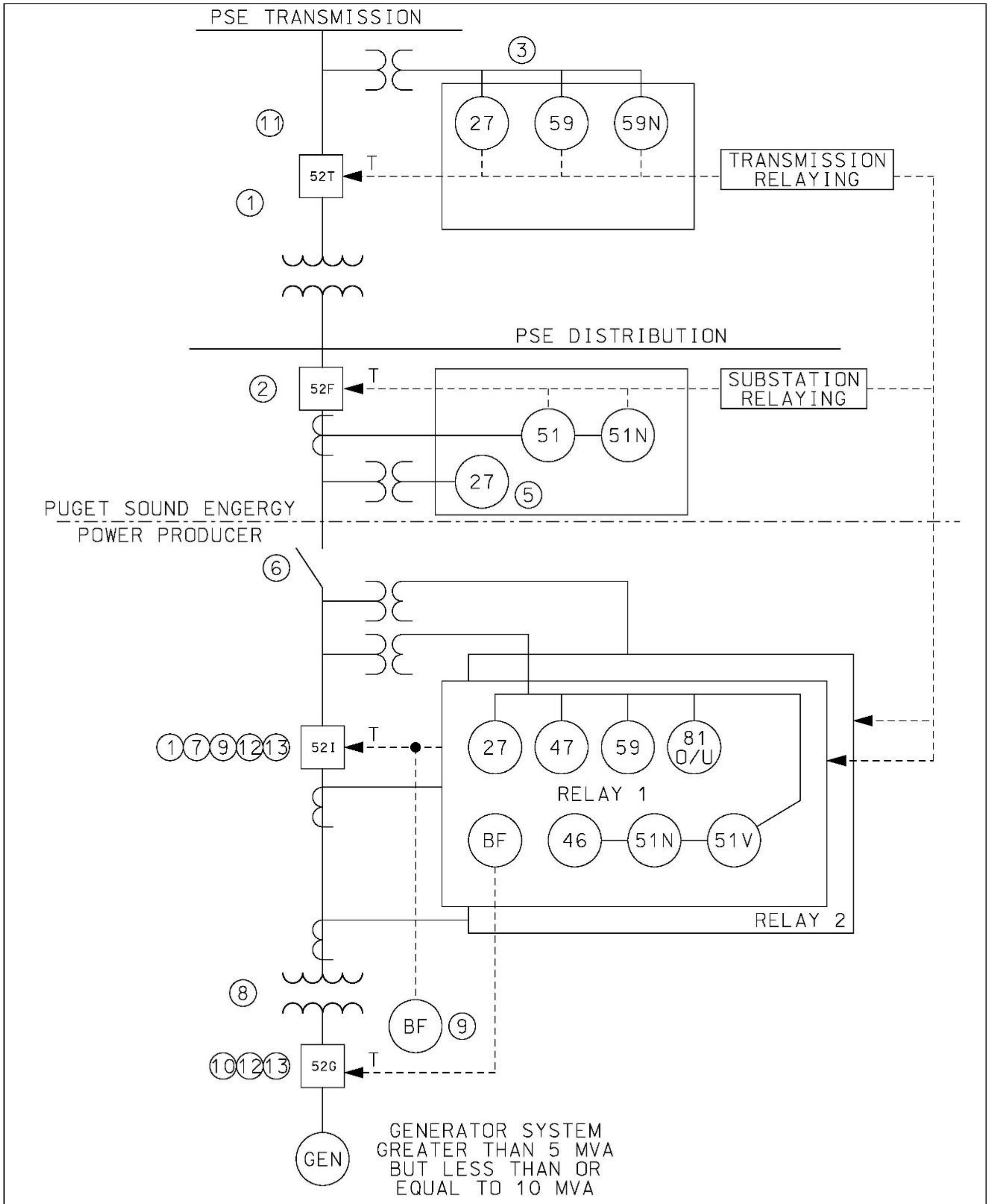
DRAWN	P. FARBER	2016-08-30	CHECKED			FILED			000905	02	00

5.4.4 Generation Facilities Greater than 5 MVA

Individual proposed generation facilities above 5 MVA will follow the study methodology in this document. Individual project requirements will be determined during the study process. See the following diagrams for an example of project requirements.



INTERCONNECT REQUIREMENTS
TIER 3 – NON INVERTER BASED
GENERATOR SYSTEM GREATER THAN 5 MVA BUT LESS THAN OR EQUAL TO 10 MVA

REVISION DESCRIPTION:			TESTED BY			DATE	/ /		PUGET SOUND ENERGY	SUBSTATION ENGINEERING DEPARTMENT	
DESIGNED	P. TIBBITS	2016-08-30	CADD			APPROVED			DRAWING NO	SHEET NO	REV NO
DRAWN	P. FARBER	2016-08-30	CHECKED			FILED			000906	01	00

1. DIRECT TRANSFER TRIP FROM PSE SUBSTATION TO 52I LIKELY REQUIRED
2. PSE SUBSTATION FEEDER BREAKER DEDICATED FOR GENERATION FACILITY
3. PSE TRANSMISSION RELAYING MAY BE REQUIRED AS PART OF GENERATOR INTERCONNECT
4.
5. CLOSE PERMISSIVE MAY BE REQUIRED
6. GANG OPERATED DISCONNECT SWITCH
7. GENERATOR INTERCONNECT RELAYING, REDUNDANT RELAYS AND INSTRUMENT TRANSFORMER REQUIRED
8. PSE TO SPECIFY INTERCONECT TRANSFORMER CONNECTION
9. BF 52I TRIPS 52G, BF 52G MUST TRIPS 52I
10. GENERATOR PROTECTION NOT SPECIFIED
11. TRANSMISSION COMMUNICATION PROTECTION LIKELY REQUIRED
12. REDUNDANT BREAKERS REQUIRED
13. SYNCH CHECK WILL BE REQUIRED AND REVIEWED

INTERCONNECT REQUIREMENTS
TIER 3 - NON INVERTER BASED
GENERATOR SYSTEM GREATER THAN 5 MVA BUT LESS THAN OR EQUAL TO10 MVA

REVISION DESCRIPTION:			TESTED BY			DATE	/ /		PUGET SOUND ENERGY — SUBSTATION ENGINEERING DEPARTMENT
DESIGNED	P. TIBBITS	2016-08-30	CADD			APPROVED			DRAWING NO: 000906 — SHEET NO: 02 — REV NO: 00
DRAWN	P. FARBER	2016-08-30	CHECKED			FILED			

5.5 PSE PROTECTION & SYSTEM UPGRADES

5.5.1 Special Protection Requirements

When the aggregate generation on a feeder, substation, or transmission line is greater than or equal to 50% of the minimum load of the feeder or Feeder Section, system modifications to PSE's system may be required to detect and clear certain faults and prevent unintentional islanding.

Certain conditions may dictate use of direct transfer trip from PSE's substation to the Generation Facility. These conditions include unacceptably slow clearing for PSE end-of-line faults, the Generation Facility being capable of carrying the minimum feeder load with the PSE source disconnected, or other undesirable conditions (such as extended over voltages or Ferro resonance) that cannot be resolved by local protection measures

5.5.2 Modifications for Distribution Interconnections

The following PSE protection system modifications may be required at the Interconnection Customer's expense in addition to the previously described requirements:

- Distribution circuits must be capable of carrying the output of the generating facility to the substations. Depending on the size of the generator this may include, but is not limited to adding a phase, increasing the wire size, removing fuses, and other modifications to the distribution circuits.
- For a Generating Facility whose total capacity is greater than or equal to 50% of the minimum load of the feeder or Feeder Section, system modifications to PSE's system may be required to detect and clear certain faults and prevent unintentional islanding.
- Certain conditions may dictate use of direct transfer trip from PSE's substation to the Generation Facility. These conditions include unacceptably slow clearing for PSE end-of-line faults, the Generation Facility being capable of carrying the minimum feeder load with the PSE source disconnected, or other undesirable conditions (such as extended over voltages or Ferro resonance) that cannot be resolved by local protection measures
- For a Generating Facility greater than 1 MVA, all existing single-phase fault interrupting devices between the generator and PSE's substation shall be replaced with three-phase interrupting devices. This will help prevent possible single-phase islanding of other PSE customers.
- When special system modifications are required on the normal feed to a Generating Facility, the generator will not be allowed to operate when fed from an alternate source, unless the alternate source has been similarly modified.
- The interconnection equipment is to be located as close as possible to the Point of Interconnection. Typical distances are within one span of overhead line or 200 feet of unspliced cable. PSE will use prudent engineering judgment to determine when additional protective devices are required at the Point of Interconnection to limit exposure to the PSE system.

5.5.3 Modifications for Impacts to the Substation

- When the aggregate generation capacity is 50% or more of the minimum load of the substation feeding the Generating Facility, and if the substation transformer feeding the Generating Facility is protected by fuses on the primary, then the fuses must be replaced with a three-phase interrupting device and necessary protection that will also trip the interconnection breaker when opened.

5.5.4 Modifications for Impacts to the Transmission System

- When the aggregate generation is greater than or equal to 50% of the minimum load of the transmission line feeding the substation, the generation must be disconnected for transmission system faults, in order to prevent islanding. Additional protection devices may be required.
- Certain conditions may dictate use of direct transfer trip between PSE's transmission stations or to the Generation Facility.
- If the generation is greater than or equal to the minimum load of the substation, the impacts on the transmission system must be studied. Groups such as Strategic System Planning and Transmission Services Planning will conduct the studies. These studies may involve affected systems, which are not bound by the timelines in the normal interconnect process and may delay studies or the interconnect date.
- These conditions may include RAS schemes, issues with clearing times, stability issues or undesired operations.

6 METERING: PSE REVENUE, OPERATIONS AND SCHEDULING REQUIREMENTS

6.1 GENERAL

Metering may be required for revenue purposes, System Operations purposes, or both, depending on the specifics of the project.

Revenue metering is required for the measurement of any function that will be billed under a PSE Scheduled Tariff. The Washington Administrative Code (WAC) requires that revenue metering be owned and operated by PSE, and that it meets stringent accuracy requirements. Even if revenue metering is not required on a project initially, it is often advisable, during the planning and construction of interconnection facilities, to include all the provisions for the possibility of future installation of PSE-owned revenue metering as retrofit installation at a later date can be extremely costly and complicated compared to the incremental cost of including those provisions during the initial construction.

Systems Operation metering is used for dispatching, reserves, accounting, and control of the PSE Distribution systems. Whether or not System Operations metering is required is the sole discretion of PSE. Often, the revenue metering can also be used to provide meter data for system operations, which is the most cost effective solution when both metering systems are necessary. If System Operations metering is required but revenue metering is not required, it may be possible for the System Operation metering to be customer-owned as Systems Operation metering does not fall under the WAC. Systems Operation metering that is customer-owned must be reviewed in advance by the PSE Electric Meter Engineering Department for function and accuracy. Accuracy must be within +/- 1.0%.

6.2 REVENUE METERING

In general, Revenue Metering installation requirements for the different categories of the Interconnection Customer-owned parallel generators are the same as those outlined in PSE's Electric Service Handbooks for Residential/Commercial/Industrial/Multifamily & Manufactured Housing Developments. In addition to the PSE Handbooks, metering installations shall comply with the requirements of the Electric Utility Service Equipment Requirements Committee (EUSERC), Section 300 or 400, as appropriate. PSE will provide a current one page EUSERC acceptability summary.

Preferably, the metering will be located on PSE's side of ownership of the electric facilities and the metering voltage shall normally be the same voltage as the Point of Interconnection for the Generating Facility output. Primary Metering Cabinet shall be required for most primary metered interconnections sized for 15kV- 600 amp main feeder or smaller, per PSE standards. If the voltage at the Point of Interconnection exceeds 15 kV, metering may be installed at the low side of the step-up transformer. In this case, loss compensation shall be applied at the meter to adjust for transformer and line losses between the meter point and the Point of Delivery. In this case, the Interconnection Customer shall provide PSE with a standard

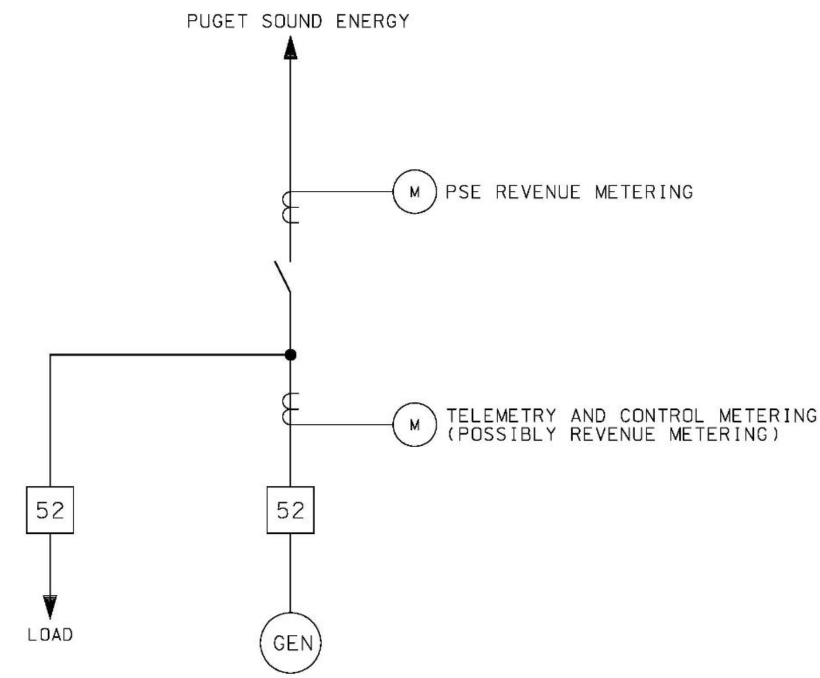
ANSI Power Transformer Test report to be used for transformer loss compensation calculations.

For Interconnection Customers who have contracted to sell the total output of the Generating Facility to PSE, two metering schemes are available.

1. **Metering Scheme Option "A"** shall be used when the Interconnection Customer's load requirements are served directly by the Interconnection Customer's generator. Bi-directional metering shall be utilized for this option, with the delivered energy registers measuring power entering the facility when load exceeds generation, and the received energy registers measuring the power leaving the facility when generation exceeds load. Metering Scheme Option “A” is illustrated in Attachment 7. This option is available where the station service loads fall within the range of accuracy for the bi-directional revenue accuracy class metering equipment.

2. **Metering Scheme Option "B"** shall be used when the Interconnection Customer has contracted to provide all generator output and PSE or another utility serves the Interconnection Customer's entire load requirements from a separate source. Two revenue meters will be used for this option. At the first metering point, the generator meter, the received energy registers of a bi-directional meter will measure the net output of the generator, that is to say the gross output of the generator minus the metered power consumed by the power production process. The delivered energy registers on the same bi-directional meter will measure the power consumed by the power production support equipment when the generator is off-line, and that is not metered separately. The second metering point, the station service meter, will measure all other loads. The Interconnection Customer is responsible for all metering costs for the generation metering. Metering Scheme Option “B” is illustrated in Attachment 8.

PSE shall provide, at the Interconnection Customer’s expense, revenue accuracy class current and potential transformers, concrete vaults, conduits, conductors, terminations, pad mounted primary metering cabinet, test switches and the meter(s) for pad mounted primary metering cabinets or overhead mounted primary metering installations where applicable. In cases where customer switchgear primary metering per EUSERC 400 is suitable, revenue accuracy class instrument transformers shall be installed by the Interconnection Customer. The Interconnection Customer is responsible for furnishing, installing, and maintaining the meter sockets, switches, enclosures, conduit, protection equipment, and all necessary wiring and connections (except CT and VT secondary wiring) where applicable.

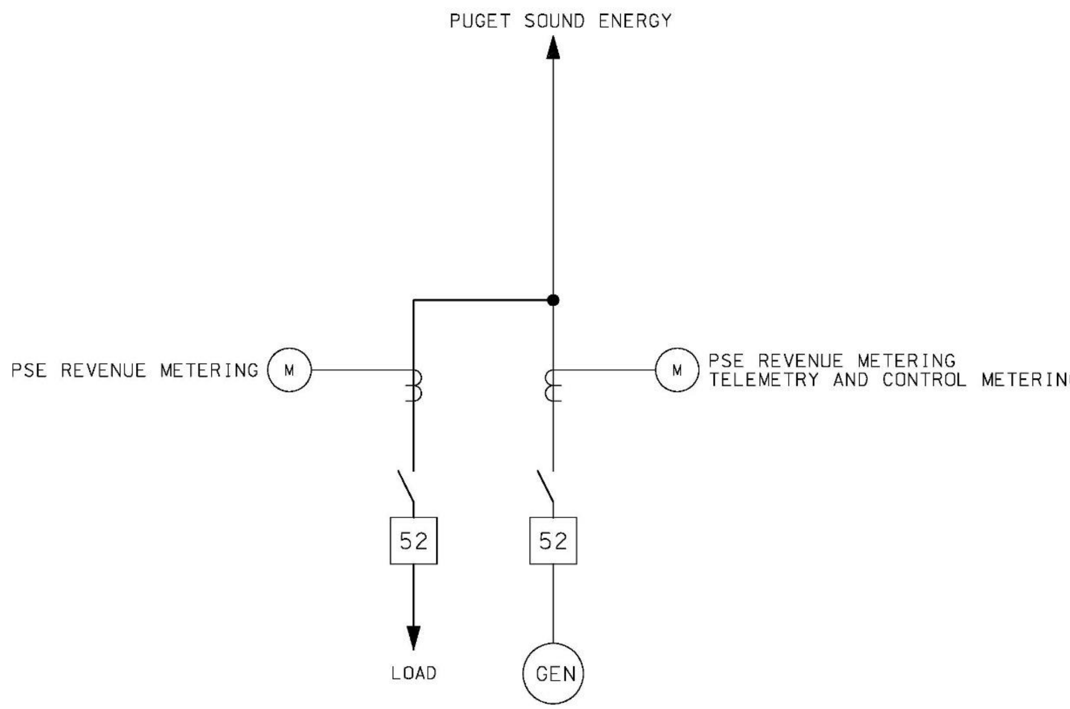


DEVICE	FUNCTION
52	AC CIRCUIT BREAKER

INTERCONNECTION REQUIREMENTS

METERING – OPTION A

REVISION DESCRIPTION:			TESTED BY			DATE	/ /		PUGET SOUND ENERGY	SUBSTATION ENGINEERING DEPARTMENT	
DESIGNED	W. WEIDERT	2019-12-10	CADD			APPROVED			DRAWING NO	SHEET NO	REV NO
DRAWN	M. POPRAVAK	2019-12-10	CHECKED			FILED			000907	01	00



DEVICE	FUNCTION
52	AC CIRCUIT BREAKER

INTERCONNECTION REQUIREMENTS

METERING - OPTION B

REVISION DESCRIPTION:			TESTED BY			DATE	/ /		PUGET SOUND ENERGY	SUBSTATION ENGINEERING DEPARTMENT	
DESIGNED	W. WEIDERT	2019-12-10	CADD			APPROVED			DRAWING NO	SHEET NO	REV NO
DRAWN	M. POPRAVAK	2019-12-10	CHECKED			FILED			000908	01	00

If wireless cellular is not available, PSE shall install fiber optic cables to the site, at the expense of the Interconnection Customer, for remote interrogation of the meter. If several meters are required, the Interconnection Customer shall provide a 1-1/2-inch conduit between meter cabinets for communication and control cables between the meters

The Interconnection Customer will provide an auxiliary single-phase 120-Volt AC source to all applicable Meter “B” points. This will provide auxiliary power to the meter in the event the interconnection metering point is de-energized.

All revenue and system operation metering installations must be reviewed and approved by the PSE Electric Meter Engineering Department prior to project installation.

6.3 SCADA RTU (REMOTE TERMINAL UNIT) METERING

Balancing Authorities, such as the one operated by PSE, are required to meet NERC and WECC standards and to conform to Good Utility Practices. System Operations uses generation SCADA RTU metering to account for reserves and load obligations. This section deals with those requirements.

6.3.1 Generator Sites with a Combined Output Less Than 2 MW

Real time monitoring is not required for generator sites having a combined output of less than 2 MW. Also, real time monitoring is not required for generators that do not operate in parallel with PSE’s system. For the purpose of this document, this includes standby generation intended for emergency use only, and generators connected to the system momentarily via closed transition switching.

6.3.2 Generator Sites with a Combined Output of 2 MW or Greater

Real-time monitoring data is required for generation sources with a combined output of 2 MW or greater. This data is sent from the generator site to PSE’s Operating Center using SCADA RTU equipment. A dedicated communication circuit is required to transmit such data, such as fiber, wireless cellular, or other connection. Generation values are transmitted continuously from the source to the Operating Center and hourly accumulations are calculated at the end of each hour for Balancing Authority accounting purposes.

These generation values are used for reserves calculations, forecasting, and for Balancing Authority energy accounting. If applicable, PSE may require indication of the spinning reserve available and for reserves under control.

The following includes specific requirements:

- Meter values sent via the SCADA RTU include bus voltage, real power (MW), energy (MWh) and reactive power (MVAR).

8

- Totalizing metering quantities from multiple generators at one site is desirable in most cases.

- PSE will determine SCADA RTU requirements for temporary generators (12 months or less) on a case-by-case basis. Energy Pre-Scheduling may be used as an alternative to a SCADA RTU for temporary sites.
- Reasonable access must be provided by the Interconnection Customer to PSE for installation, testing, and repair of the SCADA RTU equipment and circuits.
- The design, purchase, installation, testing, maintenance, and replacement of the remote generation SCADA RTU equipment will be the responsibility of PSE.

6.4 SCADA RTU REQUIREMENTS

The general SCADA RTU requirements from the Interconnection Customer to PSE are provided for each generating unit greater than or equal to 2 MW in *Table 6.5.1,* and for the Point of Interconnection the requirements are provided in *Table 6.5.2*.

PSE's 24-Hour Operating Center must have the ability to disconnect the Generating Facility from PSE's system via SCADA. Switching procedures for disconnecting the Generating Facility will vary depending upon the interconnection facility configuration.

Table 6.5.1 SCADA RTU Points on Generating Units ≥ 2 MW

Generator - Non PSE Control	• MW showing direction of flow (+ / -) • MWh delivered by PSE per hour • MWh received by PSE per hour • MVAR showing direction of flow (+ / -) • Bus Voltage • Interconnecting Breaker - Control • Alarms
Generator - Operated by PSE	• MW for each unit • MW Total Output showing direction of flow (+ / -) • MVAR Total showing direction of flow (+ / -) • MWh delivered by PSE per hour • MWh received by PSE per hour • Bus Voltage • Station Service voltage
	• Generator breaker status • Local/Remote Status • Interconnecting Breaker - Control • Start/Stop • Raise/Lower MW • Raise/Lower MVAR • Ramp Rate • Run Mode Select (peak/base) • Load Limit Select • Fuel Select (if applicable) • Alarms

7 DESIGN REVIEW AND DOCUMENTATION

7.1 REVIEW OF INTECTONNECTION CUSTOMER'S DESIGN

The PSE' Protection department will have primary responsibility for reviewing and commenting on all required protection design and associated settings. This data shall be provided after the Interconnection Customer works with PSE on the appropriate system requirements.

The Interconnection Customer shall provide the following information in addition to the requirements in Section 1.6 prior to commencement of Facilities Study:

WA State Registered Professional Electrical Engineer stamped detailed one-line diagram of entire Generating Facility system:
This drawing shows the functional arrangement of all interconnection and generation equipment using single line and standard symbol notations per ANSI 432.2 and 41.1. It must include a table that lists the equipment ratings.

An AC current and potential control schematic of the Generating Facility:
The AC schematic is a primary three line drawing showing the phasing and interconnection of the CTs and VTs with the interconnection protection. The drawings shall show all grounding of cables, CTs, etc., as well as indicating polarity.

A control schematic of the Generating Facility:
The schematic shall be functionally complete showing all DC potential circuits with all relays and control connections to the tripping and closing coils of the interconnection breaker. All relay output contacts and switches require a development table. The schematic must show the terminal designation of all devices.

A three-line diagram of the Generating Facility:
This drawing must include all the equipment shown on the one line diagram. Phasing and bushing designations for all primary equipment shall be shown.

All protective equipment ratings:
Provide ratings for all protective equipment.

Generator data:
Provide the generator data.

Ground Mat design and test data:
Provide the ground mat design and test data.

Equipment specifications and details:
This should include the specifications and details for transformers, circuit breakers, current transformers, voltage transformers, and any other major equipment or special items.

Transformer information is to include configuration, ratings, nameplate diagram, and % positive and zero sequence impedance based upon the transformer's self-cooled rating.

Specific setting information on all of the interconnection and generation relays: Information is to include the manufacturer, model, style number, and setting range information for each relay.

7.2 PSE'S REVIEW TIMELINE

PSE will review the preliminary design documentation and provide comments in a timely manner. This may include cost estimates, as appropriate, for any modifications to the PSE system required to accommodate the interconnection. PSE will also provide maximum PSE system short circuit data as requested by the Interconnection Customer.

PSE will review the final design documentation and provide comments in a timely manner. If any changes are made, the Interconnection Customer shall provide to PSE a set of revised one-lines, schematics, and construction drawings. The Interconnection Customer may elect to also supply at this time the proposed test procedure as required for PSE witnessing of tests (see *Sections 9 and 11*). This should be done in advance (at least 30 days) of the actual testing. In addition, the Interconnection Customer shall provide a copy of the electrical permit issued by the local jurisdiction prior to scheduling witness tests. Usually a coordination meeting is held with PSE and the Interconnection Customer to clarify any questions that may exist before testing begins.

7.3 AS-BUILT DOCUMENTATION DEADLINE

The final "As-Built" documentation, including all drawings and final "As-Left" relay settings, must be provided by the Interconnection Customer to PSE no later than 90 days after the date of commercial operation. If the Generating Facility is 1 MVA or greater, the final As-Built drawings shall be stamped by a Professional Electrical Engineer, registered in the State of Washington.

8 PROTECTION SETTINGS

The Interconnection Customer, in accordance with the following guidelines, shall specify all relay settings of the interconnection protection. PSE shall review and approve the settings to verify coordination with the PSE system.

The customer protection scheme shall provide the following functions:

- Clear faults and other objectionable conditions on the distribution system

- Coordinate with PSE protection equipment

- Prevent unintentional islanding of the PSE distribution system

See diagrams in Section 5 for specified protection depending on the size and type of Generators. Tier 1 or Tier 2 systems will depend on their own internal protection for the bulk of the functions. PSE will work with the customer to coordinate relaying and settings for the PSE interconnect breakers.

9 PROTECTION SYSTEM FUNCTIONAL TESTING

9.1 GENERAL

Prior to Initial Operation, the Interconnection Customer shall demonstrate to PSE that the interconnection protection system functions correctly, as described below. PSE shall not be responsible for performing such demonstration. The Interconnection Customer must provide qualified electricians, technicians, and operators to perform the demonstration(s). The Interconnection Customer must supply all personal protective equipment and designate any procedures necessary to ensure that safety precautions are taken while working near energized equipment. It is the Interconnection Customer's responsibility to demonstrate operation of all protective devices in a safe manner that does not adversely affect the PSE electric system.

Test Plan. PSE shall approve a customer written test plan/procedure prior to testing. The Interconnection Customer shall provide PSE a copy of the proposed plan at least 30 business days prior to testing. An example test plan is provided in Appendix D. The test procedures shall clearly show how the protection components and protection system will be demonstrated in a safe and non-destructive manner.

Test Scheduling. The test schedule shall be coordinated with PSE, with a minimum of 10 business days advance notice. Emergencies (i.e., storm restoration, etc.) may require test rescheduling.

> NOTE: The entire test procedure (component and system functional testing) must have been successfully completed at least once before PSE will witness the testing. These tests are referred to as the "Customer witness test" and the "PSE witness test" and shall be noted on the schedule derived during the Facilities Study. Any and all issues that appear during the "customer witness test" must be resolved prior to the "PSE witness test.

Test Equipment Calibration. All testing and calibration will be performed using test equipment of current calibration. "Current calibration" means:

- According to manufacturer's calibration specifications and intervals.
- Within a one-year interval of the last equipment calibration.
- Proof of test equipment calibration must be provided to PSE prior to testing.

Protection system functional testing shall be divided into two levels: component level testing and system level testing, as described below. The following Component and System Level Testing sections are intended to serve as general requirements. The actual demonstration will depend upon the final approved one line diagram, AC/DC schematics, relay settings, etc.

Component Level Testing. Component and relay testing is completed to ensure that components function per design and within industry and manufacturer's tolerances, the agreed-upon settings are used on each of the relays required by PSE, and the relays are functional and calibrated to manufacturer's tolerances.

Certified manufacturer's test reports may be provided in lieu of performing tests for current and voltage transformers. Certification test reports must be per standard IEEE C57.13. Certified test reports may also be accepted for other components, but this shall be coordinated with PSE in advance, contingent on PSE approval and documented in the customer-written test plan.

System Level Testing. Protection System Functional Testing is completed to ensure that each of the required relays is properly connected to the instrument transformers and operates the proper interrupting device.

9.2 COMPONENT LEVEL TESTING

9.2.1 Current Transformer (CT)

Visually check polarity mark orientation on all CTs with respect to the AC schematics in the design drawings. Perform polarity checks of the CTs per the most current version of ANSI Standard C57.

The following calibration tests shall also be performed:

- Verify the CT polarity.
- Verify that all grounding, shorting connections, and test blocks provided make good contact.
- CT single point grounding shall be confirmed for each CT circuit as shown on the drawings, with the preferred grounding location at or near the relay panel.
- Ratio CTs at specified tap ratio.
- Perform Megger® tests on all CTs to ground.
- Perform demagnetization and excitation tests on CTs as the final tests on CTs.
- Check excitation test data against CT excitation curves.

9.2.2 Voltage Transformer (VT), Potential Device (PD), Capacitor Voltage Transformer (CVT), and Coupling-Capacitor Voltage Transformer (CCVT)

Visually check polarity mark orientation on all VTs, PDs, CVTs, and CCVTs with respect to the three-line diagrams in the design drawings and the manufacturer's drawings. Test all polarities per the most current version of ANSI Standard C57.13.

- Verify polarity electrically relative to polarity marks.
- Verify ratio at specified tap.
- Verify VT, PD, CVT, and CCVT circuit single point grounding as shown on the drawings.
- Doble® power factor test all VTs, CVTs, and CCVTs.
- Adjust the PDs for the voltage and the burden of the secondary circuits to that they are being connected.

9.2.3 Relays

Relays shall be tested with actual PSE-approved setting values to verify calibration, input mapping, and output mapping. All elements (under voltage, over voltage, etc.) listed in the PSE-approved relay settings shall be tested.

9.3 SYSTEM LEVEL TESTING

All required relays shall be functionally operated to demonstrate proper interrupting device operation. Tests should be performed off-line, if possible. Tests that cannot be performed off-line must be demonstrated to operate on-line. Trip outputs and interlocks from the relay may be arrived at either by manually operating all appropriate contacts, or by injecting an electrical signal to cause a trip output.

Check continuity of the CT circuit to each relay by primary injection. Following energization, verify correct voltage polarity at relays (where applicable).

Demonstrate that the interlocks between the generator and the interconnection breaker(s) operate properly (e.g., Interconnection Customers cannot energize a dead line and can only tie to a hot line via a synchronizing device).

10 DEMONSTRATION OF GENERATING SYSTEM CONTROLS AND FUNCTIONALITY

After Protection System Functional Testing, Initial Operation and synchronization, Interconnection Customers shall demonstrate to PSE the generator voltage controls and required reactive capabilities, and the dispatch controls and monitoring equipment. PSE shall not be responsible for performing such demonstration(s). Interconnection Customers shall provide qualified personnel to perform the demonstrations. The Interconnection Customer must supply all personal protective equipment and designate any procedures necessary to ensure that safety precautions are taken while working near energized equipment. It is the responsibility of the Interconnection Customer to supply to PSE the actual written test procedures that incorporate the following types of tests, for PSE's review prior to actual demonstration of functionality.
Test Plan. PSE shall approve a customer written test plan/procedure prior to testing. The Interconnection Customer shall provide PSE a copy of the proposed plan at least 30 business days prior to testing. The test procedures shall clearly show how the generating system controls and parameters will be demonstrated in a safe and non-destructive manner. An example test plan is provided in Appendix D.

Test Scheduling. The test schedule shall be coordinated with PSE, with a minimum of 10 business days advance notice. Emergencies (i.e., storm restoration, etc.) may require test rescheduling.

> NOTE: The entire test procedure (component and system functional testing) must have been successfully completed at least once before PSE will witness the testing.

10.1 POWER FACTOR (PF) CONTROLLER TEST, IF APPLICABLE

This test is intended to demonstrate that the Generating Facility (less than 5 MVA) added to the PSE distribution system will automatically disconnect when PF goes outside the limits established in *Section 3.3*. This test is to be done with plant load that can be interrupted during test procedures. An example of the test plan is provided in Appendix D.

10.2 VAR CAPACITY TESTS

The Interconnection Customer is advised that for distribution-connected generators there may be significant VAR losses absorbed into the generator's step-up transformer. These losses will impact the Generating Facility's net VAR capability (and PF) when the metered Point of Interconnection is on the HV side of the transformer.

10.2.1 Distribution Connected Generators

Generators must demonstrate that it will maintain 0.95 leading or lagging power factor from minimum load up to 100% rated generator MW or real power load at the Point of Interconnection. The capacity tests into the lead may be limited because of operational limitations due to manufacturer's design criteria or stator end iron heating concerns. See *Section 3.3* for power factor requirements.

10.3 BATTERY ENERGY STORAGE DEVICE INITIAL AND PERIODIC TESTING

Battery Energy Storage installations shall meet testing requirements to be determined.

10.4 HARMONIC TESTING

Customer shall perform tests to meet Harmonic requirements stated in Section 3.2.

10.5 PRODUCTION CONTROL TESTING

Customer shall perform tests to meet specified Ramp Rates as stated in Section 4.8.

11. GENERAL MAINTENANCE REQUIREMENTS

11.1 INSPECTION

PSE may inspect Interconnection Customer's facilities whenever it appears that the Interconnection Customer is operating in a manner hazardous to PSE's system integrity and/or customer safety. Interconnection Customer shall perform functional testing of all breakers, relays, and instrument transformers at least every 5 years, at the Interconnection Customer's expense and provide results to PSE when requested.

11.2 DESIGN CHANGES AFTER COMMERCIAL OPERATION

The interconnection customer, prior to implementation, must submit to and receive written approval from PSE for any material modifications to the facility.

Example of material modifications are:

- An increase in generation output.
- An increase of 20% of station service load.
- Control, configuration, or protection changes for the main generators, main inverters or main transformers.

Demonstration of Relay Calibration, Trip and Circuit Tests, and On-Line Startup Testing may be required depending on the extent of the modifications.

Setting or control device changes of any interconnection protection or synchronizing device must be approved by PSE and submitted in a format acceptable to PSE.

Any "Field Modification" or "As-Built" AC/DC protection and synchronizing schematics associated with any interconnection device must be forwarded to the designated PSE representative The final As-Built drawings shall be stamped by a Professional Electrical Engineer, registered in the State of Washington.

PSE system changes may necessitate additional interconnection protection being required, which shall be paid for by the Interconnection Customer. For example, line reconfigurations may result in the Interconnection Customer's generation being greater than 50% of the high line minimum load. Therefore, high side VTs, under/over voltage relaying, and direct transfer trip to the Generating Facility may be required to avoid the parallel generator islanding the PSE system for a high side single-phase to ground fault.

12. OPERATING REQUIREMENTS

12.1 SWITCHING AND TAGGING RULES

The Interconnection Customer must review personnel safety practices for tagging and switching equipment with PSE. The Interconnection Customer must comply with these practices and obtain or provide clearances for work and for switching operations on equipment, accordingly.

12.2 DE-ENERGIZED CIRCUITS

A generation source shall not energize a de-energized PSE circuit under any circumstances unless under the direct orders of PSE's System Operator. Failure to observe this requirement will be cause for immediate (and possibly permanent) disconnection of the Generating Facility.

12.3 OPERATING LOG

The Interconnection Customer shall maintain an operating log at each Generating Facility 500 kVA and over that parallels with the PSE system. The log shall indicate changes in operating status, trip operations, and other unusual conditions. The operating log shall be open to review by PSE at any time in order to help resolve interconnected operating issues.

The Generating Facility Operator will cooperate with PSE in the analysis of disturbances to the Facility's generator or PSE's electric system by gathering and providing access to information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations, and sequence of events records.

12.4 COMMUNICATIONS - FACILITIES THAT REQUIRE SCADA

Generation sites that require SCADA must provide the following:

- A 24-hour phone for the Generating Facility operator. The Generating Facility operator shall also have information for contacting PSE's System Operator.
- Plant operating personnel shall be familiar with and follow line clearance/operating safety procedures and applicable standard practices.
- Notification to PSE's System Operator prior to bringing any generating unit on-line, unless procedures are approved for automatic restoration, as defined in the interconnection agreement.
- Immediate notification to PSE's System Operator of unplanned trip operations.

12.5 DISCONTINUANCE OF PARALLEL OPERATIONS

Interconnection Customers shall discontinue parallel operation when requested by PSE, as follows:

- To facilitate maintenance, test, or repair of PSE facilities.
- To accommodate line clearances or non-recloses on associated circuit. PSE will notify the generator operator in advance of planned clearances or non-recloses. During emergencies, PSE may not be able to give advance warning of being disconnected from the system.
- When the Interconnection Customer's generating equipment is interfering with customers on the system due to degradation of power quality or service.
- When an inspection of the Interconnection Customer's generating equipment reveals a condition hazardous to the PSE system or a lack of scheduled maintenance or maintenance records for equipment necessary to protect the PSE system.
- When Good Utility Practices warrant discontinued operation.

12.6 STATION SERVICE, STARTUP POWER AND BACKFEED POWER

Power provided for local use at a generating facility or substation to operate lighting, heat auxiliary or other equipment is defined as station service. In addition, power generated by a generator and then consumed by equipment that contributes to the generation process is considered as station service. Alternate station service is a backup source of power, only used in emergency situations or during maintenance when primary station service is not available.

Station service is the responsibility of the Interconnection Customer.

Appropriate providers of station service and alternate station service are determined during the project planning process and the Interconnection Customer is required to provide metering for station service and alternate station service. Arrangement for station service, startup power and backfeed power is required prior to energization, testing and commissioning. This is to be identified on the Schedule derived in the Facilities Study.

PSE 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 or distribution line that interconnects PSE 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.

APPENDIX D

EXAMPLE TEST PLAN

The following example plan is provided to indicate what is needed in a typical test plan. It does not cover all cases. Customer is responsible to create a test plan specific to their facility.

GENERAL

The system to be under test includes the [*Project Name]* intertie equipment consisting of protective relays, circuit breakers, power supplies, voltages transformers (VT's), current transformers (CT's), and interconnecting wiring.

The purpose of the testing defined in this procedure is to assure protective equipment required by Puget Sound Energy (PSE) is installed in accordance with design specifications and operates within industry and manufacturer's tolerances.

Successful completion of all testing defined herein is required prior to interconnection with the PSE system. Testing shall be witnessed by a PSE representative.

This entire test procedure (component testing, relay functional testing, and system functional testing) identified as the "Customer witness test" must have been successfully completed at least once before "PSE witness" procedure.

TEST EQUIPMENT

The following test equipment is needed to complete this test procedure (actual test equipment shall be listed).

- Two digital multimeters with [nn] A current range
- Appropriate power supply for system power
- Three-phase independent voltage sources (0 to [nn]% of nominal voltage) with variable phase angle to simulate VT inputs
- Three-phase independent current sources (0 to [nn]% of CT rating) with variable phase angle to simulate CT inputs
- Electronic timer accurate to at least [n] ms.

PROTECTION SYSTEM COMPONENT TESTING

GENERAL

Component and relay testing is completed to ensure that components function per design and within industry and manufacturer's tolerances, the agreed-upon settings are used on each of the relays required by PSE, and that the relays are functional and calibrated to manufacturer's tolerances.

Protection System Functional Testing is completed to ensure that each of the required relays is properly connected to the instrument transformers and operates the proper interrupting device.

CURRENT TRANSFORMER (CT)

Visually check polarity mark orientation on all CTs with respect to the AC schematics in the design drawings. Perform polarity checks of the CTs per the most current version of ANSI Standard C57.13.1.

The following calibration tests shall also be performed:

- Verify that all grounding, shorting connections, and test blocks provided make good contact.
- CT single point grounding shall be confirmed for each CT circuit as shown on the drawings, with the preferred grounding location at or near the relay panel.
- Ratio CTs at specified tap ratio.
- Perform Megger® tests on all CTs to ground.
- Perform demagnetization and excitation tests on CTs as the final tests on CTs. Check excitation test data against CT excitation curves.

TEST EQUIPMENT CALIBRATION

All testing and calibration of CTs and relays will be performed using test equipment of current calibration. “Current calibration” means:

- According to manufacturer’s calibration specifications and intervals.
- Within a one-year interval of the last equipment calibration.

Proof of test equipment calibration must be provided to PSE prior to relay testing.

CONTROL AND SIGNAL WIRING

Visually check all control and signal wiring connections between protective relay inputs and outputs and field devices.

PROTECTIVE RELAY(S) COMPONENT TESTING

Purpose: To verify the operation of both relay installations in a redundant configuration.

Load PSE approved settings into relays (to be completed prior to the start of witness testing). *[An example of typical relay settings is included at the end of this test plan.]*

Provide PSE representative with a copy of the relay settings file. PSE representative will compare these settings to PSE approved settings.

It is recommended that a digital or hard copy of these pre-test settings be retained to aid in ensuring that all settings that may have been changed to facilitate testing are restored to their correct values after testing is complete.

NOTE: In the testing defined below, if testing one protective element may cause another element(s) to operate, it is recommended that the untested element(s) be disabled.

PHASE UNDER/OVER VOLTAGE (27/59I)

Purpose: To verify the operation and accuracy of the 27and 59 protection elements.

NOTE: In the overvoltage testing below, if test equipment is not capable of requested voltage levels, testing may be done with nominal voltage set to [nnn] volts line to ground (instead of [nnn] volts line to ground).

Phase Under/Over Voltage Trip Setting (Pickup) Verification

Step 1: Monitor the 27 and 59 function operation. Operation verified by monitoring *[interconnect breaker trip output contact name]* normally open contact.

Step 2: Connect and apply a [nnn] VAC LG variable voltage, three-phase voltage source to the relay voltage input terminals.

Step 3: Slowly decrease the A-phase voltage until *[interconnect breaker trip output contact name]* closes. *[Interconnect breaker trip output contact name]* should close within ±[n.n]% of the 27 pickup setting. Slowly increase the A-phase voltage until *[interconnect breaker trip output contact name]* opens. *[Interconnect breaker trip output contact name]* should open within ±[n.n]% of the 27 pickup setting. Verify the 27 target on the relay front panel or software GUI. Reset the target.

Step 4: Continue increasing the A-phase voltage until *[interconnect breaker trip output contact name]* closes. Pickup should occur within ±[n.n]% of the lower 59 pickup setting. Slowly reduce the A-phase voltage until *[interconnect breaker trip output contact name]* opens. Dropout should occur within ±[n.n]% of the lower 59 pickup setting. Verify lower 59 target on the relay front panel or software GUI. Reset the target.

Step 5: Disable 59 element with lowest pickup setting.

Step 6: Continue increasing the A-phase voltage until *[interconnect breaker trip output contact name]* closes. *[interconnect breaker trip output contact name]* should close within ±[n.n]% of the upper 59 pickup setting. Slowly reduce the A-phase voltage until *[interconnect breaker trip output contact name]* opens. *[interconnect breaker trip output contact name]* should open within ±[n.n]% of the upper 59 pickup setting. Verify upper 59 target on the relay front panel or software GUI. Reset the target.

Step 7: Disable 59 element with higher pickup setting.

Step 8: Continue increasing the A-phase voltage until *[interconnect breaker trip output contact name]* closes. *[interconnect breaker trip output contact name]* should close within ±[n.n]% of the 59 pickup settings. Slowly reduce the A-phase voltage until *[interconnect breaker trip output contact name]* opens. *[interconnect breaker trip output contact name]* should open within ±[n.n]% of the 59I pickup settings. Verify 59I target on the relay front panel or software GUI. Reset the target.

Step 9: Enable lower and upper 59 elements.

Step 10: Repeat Steps 3 through 9 for the B-phase and C-phase voltage inputs.

Phase Under/Over Voltage Timing (Delay) Verification

Step 1: Monitor 27 and 59 element timing. Timing accuracy is verified by measuring the delay between a step voltage change and *[interconnect breaker trip output contact name]* contact closure.

Step 2: Connect and apply a [nnn] VAC LG, variable voltage three-phase voltage source to the relay voltage input terminals.

Step 3: Step the A-phase voltage down to [nnn] volts LG ([nnn] volts LG if relay nominal voltage is set to [nnn] volts line to ground). Measure the time delay between the voltage step change and *[interconnect breaker trip output contact name]* contact closure. Measured delay shall be within ± *[insert manufacturer's tolerance here]* cycles of the time delay setting. Reset A-phase voltage to [nnn] VAC LG. Verify *[interconnect breaker trip output contact name]* contacts open.

Step 4: Step the A-phase voltage up to [nnn] volts LG ([nnn] volts LG if relay nominal voltage is set to [nnn] volts line to ground). Measure the time delay between the voltage step change and *[interconnect breaker trip output contact name]* contact closure. Timing accuracy shall be within ±*[insert manufacturer's tolerance here]* cycles of the time delay setting. Reset A-phase voltage to [nnn] VAC LG. Verify *[interconnect breaker trip output contact name]* contacts open.

Step 5: Step the A-phase voltage up to [nnn] volts LG ([nnn] volts LG if relay nominal voltage is set to [nnn] volts line to ground). Measure the time delay between the voltage step change and *[interconnect breaker trip output contact name]* contact closure. Timing accuracy shall be within ±*[insert manufacturer's tolerance here]* cycles of the time delay setting. Reset A-phase voltage to [nnn] VAC LG. Verify *[interconnect breaker trip output contact name]* contacts open.

Step 6: Reset targets.

Step 7: Repeat Steps 2 through 6 for the B-phase and C-phase voltage inputs.

Step 8: Change nominal voltage back to [nnn] volts line to neutral if it was changed.

UNDER/OVER FREQUENCY (81)
Purpose: To verify the operation and accuracy of the 81 protection elements.

Under/Over Frequency Trip Setting (Pickup) Verification

Step 1: Monitor 81 function operation. Operation verified by monitoring the status of the *[interconnect breaker trip output contact name]* contact or software GUI screen.

Step 2: Connect and apply a [nnn] VAC LG, 60-hertz voltage source to the relay voltage input terminal(s) used by the 81 elements.

Step 3: Slowly decrease the frequency of the applied voltage until *[interconnect breaker trip output contact name]* closes. Contact closure should occur within ±*[insert manufacturer's tolerance here]* hertz of the pickup setting. Verify 81 target on the relay front panel or software GUI. Slowly increase the frequency until *[interconnect breaker trip output contact name]* opens. Contacts should open within ± *[insert manufacturer's tolerance here]* hertz of the pickup setting. Reset the target.

Step 4: Slowly increase the frequency of the applied voltage until *[interconnect breaker trip output contact name]* closes. Pickup should occur within ± *[insert manufacturer's tolerance here]* hertz of the pickup setting. Verify 81 target on the relay front panel or software GUI. Slowly decrease the frequency until *[interconnect breaker trip output contact name]* opens. Contacts should open within ± *[insert manufacturer's tolerance here]* hertz of the pickup setting. Reset the target.

Step 5: Repeat Steps 2 thru 4, on B and C phases.

<u>Under/Over Frequency Timing (Delay) Verification</u>

Step 1: Monitor 81element timing. Timing accuracy is verified by measuring the delay between a step frequency change and *[interconnect breaker trip output contact name]* contact closure.

Step 2: Connect and apply a [nnn] VAC LG, 60-hertz voltage source to the relay voltage input terminal(s) used by the 81 elements.

Step 3: Step the frequency of the applied voltage down from 60 hertz to a value below the 81 under frequency setting. Measure the time delay between the frequency step change and *[interconnect breaker trip output contact name]* closure. Timing accuracy shall be ±*[insert manufacturer's tolerance here]* cycles of the time delay setting. Reset A-phase frequency to 60 Hertz. Verify *[interconnect breaker trip output contact name]* contacts open. Reset the target.

Step 4: Step the frequency of the applied voltage up from 60 hertz to a value above the 81 over frequency setting. Measure the time delay between the frequency step change and *[interconnect breaker trip output contact name]* closure. Timing accuracy shall be ±*[insert manufacturer's tolerance here]* cycles of the time delay setting. Reset A-phase frequency to 60 Hertz. Verify *[interconnect breaker trip output contact name]* contacts open. Reset the target.

Step 5: Repeat Steps 2 through 4 for B and C phases.

OVERCURRENT PICKUP AND TIMING VERIFICATION (51V and 51N)

Purpose: To verify the operation and accuracy of the 51 over current protection elements.

<u>Over Current Minimum Trip Setting (Pickup) and Timing Verification</u>

Step 1: Monitor 51V element operation. Operation verified by monitoring the status of the *[relay breaker trip output contact name]* contact or software GUI screen.

Step 2: Disable 51N element.

Step 3: Connect a variable (*[nn]* to *[nn]* amp range) current source to the relay A phase current input terminals.

Step 4: Step input current to four times 51V element pickup. *[relay breaker trip output contact name]* contact should close in *[insert calculated time here]* cycles, ±*[insert manufacturer's tolerance here]* cycles, of output current reaching pickup value. Verify the 51 target on the relay front panel or software GUI. Reset current input to zero. Reset the target.

Step 5: Step input current to eight times 51V element pickup. *[relay breaker trip output contact name]* contact should close in *[insert calculated time here]* cycles, ±*[insert manufacturer's tolerance here]* cycles, of output current reaching pickup value. Verify the 51 target on the relay front panel or software GUI. Reset current input to zero. Reset the target.

Step 6: Repeat steps 3 through 5 for B and C phases.

Step 7: Disable 51V element. Enable 51N element.

Step 8: Connect a variable (*[nn]* to *[nn]* amp range) current source to the relay A phase current input terminals.

Step 9: Step input current to four times 51N element pickup. *[relay breaker trip output contact name]* contact should close in *[insert calculated time here]* cycles, ±*[insert manufacturer's tolerance here]* cycles, of output current reaching pickup value. Verify the 51 target on the relay front panel or software GUI. Reset current input to zero. Reset the target.

Step 10: Step input current to eight times 51N element pickup. *[relay breaker trip output contact name]* contact should close in *[insert calculated time here]* cycles, ±*[insert manufacturer's tolerance here]* cycles, of output current reaching pickup value. Verify the 51 target on the relay front panel or software GUI. Reset current input to zero. Reset the target.

Step 11: Enable 51V element. Also enable any other elements that were disabled to facilitate testing.

PROTECTION SYSTEM FUNCTIONAL TESTING

INTEGRATED COMPONENTS AND EQUIPMENT BEING TESTED:

- [Insert manufacturers name and model] protection relays
- Primary and backup circuit breakers (52)
- Capacitor Breaker (52)
- Lockout relays (86)
- CTs

- Interconnecting wiring
- Uninterruptable power supply

Testing described below may be completed using methods described in the PROTECTION SYSTEM COMPONENT TESTING and PROTECTIVE RELAY FUNCTIONAL TESTING sections above.

TRIP CHECK

Procedure	Test Result (Pass/Fail)
1. Simulate a 27 under voltage condition.	
2. Confirm primary, backup, and capacitor breakers trip.	
3. Confirm relay trip output indicator lights illuminate on both relays.	
4. Confirm 27 targets on front panel of both relays.	
5. Reset tripped breakers to closed position. Reset relay front panel targets.	
6. Confirm system is restored to normal operating configuration.	

Comments:

BREAKER FAILURE FUNCTION (BF)

Procedure	Test Result (Pass/Fail)
1. Isolate primary relay to test breaker failure function independent of backup relay.	
2. Simulate breaker failure condition as in PROTECTIVE RELAY FUNCTIONAL TESTING section above.	
3. Confirm primary relay initiates trip of lockout relay.	
4. Confirm lockout relay initiates trip of backup breaker and capacitor breaker	
5. Reset lockout relay and circuit breakers.	
6. Repeat steps 2 through 6 for backup relay.	
7. Repeat steps 2 through 6 with primary and backup relays simultaneously functioning.	
8. Confirm system is restored to normal operating configuration.	

Comments:

BREAKER FAILURE (BF)

Purpose: To verify the operation of the breaker failure (BF) function.

Step 1: Open the trip element wire to the trip coil of the primary breaker. This will allow the relays to send a trip signal but the primary breaker will not trip because the wiring to the trip coil has been opened. Place meter on *[interconnect breaker trip output contact name]* of each active relay to show that no breaker failure trip signal is present.

Step 2: Confirm the primary breaker is not tripped. Reset if required.

Step 3: Confirm the lockout relay is not tripped. Reset if required.

Step 4: Confirm backup breaker is not tripped. Reset if required.

Step 5: Confirm that both relays do not have an alarm or a trip. Reset alarms or trip indication on the relays if required.

Step 6: Open the incoming voltage to relays. This simulates a three phase under voltage condition at the relays.

Step 7: Confirm both relays' trip indicator lights activate.

Step 8: Confirm the primary breaker is not tripped due to the trip coil wire being open (see Step 1).

Step 9: Place meter on primary breaker status (52A) inputs on both relays to show the state of the primary breaker is closed.
Step 10: Confirm the lockout relay trips as a result of the breaker failure timer (62) output contact closing on the primary relay. Place meter on breaker failure output contact of each active relay to show the breaker failure trip has been initiated.

Step 11: Confirm backup breaker trips as a result of the lockout relay tripping.

Step 12: …

Step 13: …

Step nn: Return system to normal configuration. Compare relay settings to pre-test settings from above to ensure system is restored to its pre-test configuration.

CONTROL POWER FAILURE

Procedure	Test Result (Pass/Fail)
1. Simulate loss of control power by opening 15A breaker on existing house panel.	
2. Simulate a 27 under voltage condition.	
3. Confirm primary, backup, and capacitor breakers trip OR loss of control power alarm is set.	
4. Reset relays and breakers to closed position.	
5. Confirm system is restored back to normal operating configuration.	
6. Ensure all three overvoltage 59/59I elements are enabled.	
7. Change nominal voltage back to 277 volts line to neutral if it was changed.	
8. Compare relay settings to pre-test settings from above to ensure system is restored to its pre-test configuration.	

Comments:

CONCLUSION

Witness Test Approval

I have witnessed the required testing and determine the testing defined herein to:

Pass Fail

Notes

The signature of a Puget Sound Energy (PSE) representative below does not constitute PSE approval to connect to the PSE system. Approval to connect to the PSE system will be in the form of a Certificate of Operation that will be issued, if appropriate, after PSE has completed a final review of related data.

Testing Agent____Date__________

PSE Representative__________________________________ Date__________

Owner's Representative______________________________ Date__________

[Project Name] Relay Settings

Below are suggested relay settings based on PSE interconnection technical specifications (PSE-ET-160.70). These are only suggestions. Customer shall determine suitability of these settings for customer equipment.

Primary Relay	**Backup Relay**	**IEEE Relay Function**	**Description**
[nnn]% with [nnn] cycle delay		27	Undervoltage with Time Delay
[nnn]% with [nnn] cycle delay [nnn]% with [nnn] cycle delay		59 59	#1 Overvoltage with Time Delay #2 Overvoltage with Time Delay
[nnn]% with [nnn] cycle delay		59I	Instantaneous Peak Overvoltage
[nnn] Hz with [nnn] sec delay		81O	Overfrequency
[nnn] Hz with [nnn] sec delay		81U	Underfrequency
[nnn] sec delay		62BF	Breaker Fail (if needed)
Pickup: [nnn]A Time Dial: [nnn] Curve: [nnn]		51P	Phase Overcurrent
Pickup: [nnn] A Time Dial: [nnn] Curve: [nnn]		51N	Ground Overcurrent
[nnn] kW with [nnn] cycle delay		32	Reverse Power
±[nnn] Hz, ±[nnn] deg, ±[nnn] V		25	Synch Check
[nnn] with [nnn] cycle delay		47	Negative Sequence Overvoltage
[nnn] with [nnn] cycle delay		46	Negative Sequence Overcurrent
[nnn]		60FL	Fuse Loss