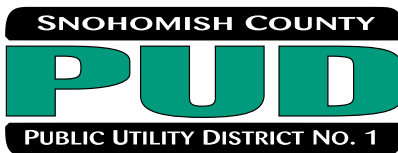


INTERCONNECTION REQUIREMENTS TRANSMISSION

Revision 3

June 2026

Distribution & Engineering Services Division
Snohomish County Public Utility District No.1
Everett, Washington



Energizing Life in Our Communities

We deliver essential utility services to help our communities thrive.

Snohomish County Public Utility District No. 1
Everett, Washington
INTERCONNECTION REQUIREMENTS: TRANSMISSION

Revised
June 18, 2026
Prepared by

System Planning & Protection Group
Distribution & Engineering Services Division

Updated by: *Emily Parry*
Emily Parry (Jun 18, 2026 10:29:49 PDT)
Emily Parry, Engineer III
System Planning & Protection

Approved: *Jeanne Harshbarger*
Jeanne Harshbager, Manager
System Planning & Protection

Approved: *Amy Carstens*
Amy Carstens (Jun 18, 2026 16:33:58 PDT)
Amy Carstens, Senior Manager
Transmission & Distribution Engineering & Operations

Contents

- 1 Glossary 6
- 2 Interconnection Process 8
 - 2.1 Overview 8
 - 2.2 Project Study Requirements 8
 - 2.3 Study Process Summary 10
 - 2.3.1 Phase 1: Feasibility Review 11
 - 2.3.2 Phase 2: System Impact Study (SIS)..... 11
 - 2.3.3 Phase 3 – Generation/Line: Interconnection Facilities Study 13
 - 2.3.4 Phase 3 – Large Load: New Large Load Policy 13
 - 2.3.5 Phase 4: Interconnection Agreement..... 14
 - 2.4 Required Data 14
 - 2.5 Cost Allocation Policy 15
 - 2.6 Qualified Change Definition 15
 - 2.7 Related Requirements and Policies 16
 - 2.8 Coordination with External Entities 17
 - 2.9 Ancillary Services 17
 - 2.10 District’s Protection Philosophy 18
 - 2.11 Technical Requirements - General..... 18
- 3 Technical Requirements – Transmission System..... 19
 - 3.1 Load (End-User) Facilities and Line Facilities..... 19
 - 3.1.1 Voltage..... 19
 - 3.1.2 Power Factor 19
 - 3.1.3 Phase Unbalance 19
 - 3.1.4 Underfrequency Load Shedding..... 19
 - 3.1.5 Facilities 20
 - 3.2 Load Facilities Protection..... 20
 - 3.3 Generation Facilities..... 20
 - 3.3.1 Voltage..... 20
 - 3.3.2 Real Power 20
 - 3.3.3 Reactive Power..... 20
 - 3.3.4 Voltage Control 21
 - 3.3.5 Frequency Control..... 21
 - 3.3.6 Energy Storage Requirements 22

3.3.7	Phase Unbalance	22
3.3.8	Harmonics	22
3.3.9	Facilities	22
3.4	Generation Facilities Protection	22
3.4.1	General Protection.....	22
3.4.2	Frequency Protection	23
3.4.3	Voltage Protection	23
3.4.4	Teleprotection.....	24
3.4.5	Breaker Duty	24
3.4.6	Utility Tie Breaker(s) Owned by the Customer.....	25
3.4.7	Disturbance Monitoring	25
3.4.8	Automatic Reclosing.....	25
3.4.9	Automatic Disconnection and Time-Delayed Automatic Reconnection.....	25
3.4.10	Surge Protection.....	26
3.4.11	Lightning Surges.....	26
4	Generation Facility Requirements	26
4.1	Placement of Generating Facilities.....	26
4.2	Visible Disconnect Switch Requirements.....	27
4.3	Generation Equipment Ratings.....	27
4.4	Generation Starting as Induction Motor	28
4.5	Islanding	28
4.6	Right to Disconnect	28
4.7	Inverter Performance Requirements	28
5	General System Details.....	28
5.1	Grounding Requirements.....	28
5.2	Equipment Ratings	29
5.3	Telecommunication Requirements	29
5.3.1	Communication Requirements.....	29
5.3.2	Dedicated Communications Link for Pilot Relaying	30
5.3.3	Dedicated Communications Link for SCADA.....	30
5.3.4	General Telemetry Requirements	30
5.4	Commissioning Requirements.....	32
5.4.1	Start-Up (Initial Energization Inspection).....	32
5.5	Operations and Metering Requirements	33
5.5.1	Revenue and Interchange Metering.....	33

5.5.2	Generation Metering System.....	33
5.5.3	Synchronizing of Facilities.....	33
5.5.4	Primary Metering	34
5.6	Maintenance Requirements	34
5.6.1	Maintenance Coordination	34
6	Documentation Requirements & Revision History.....	34
7	Appendix A: Form 6-1	36
8	Appendix B: Form 6-2	37
9	Appendix C: New Service Questionnaire (NSQ).....	38

1 Glossary

Applicant - The utility, developer or other entity that requests a new or modified connection for a line, load, or generation resource and includes both current District customers served under one of its retail electric rate schedules and entities that are not currently District electric customers but who intend to connect in the District's electric system

Applicant's Operator – The Company that operates a load delivery, transmission interconnection, or generation facility, which plans to connect to the District's electric system.

Point of Interconnection (POI) - The physical location on the power system where there is a change of ownership between the District and the facility that wants to connect.

Facility – The load delivery (end-user), transmission connection, or generation facility and all equipment associated with the Facility up to the Point of Interconnection with the District. The District owns none of the facilities that make up the Facility.

Feasibility Review – First high-level review of the proposed interconnection in the study process. This study identifies basic parameters of the interconnection, to determine which processes and technical requirements apply, and to provide a non-binding outline of key equipment and work which may be needed

IBR – Inverter Based Resource. Any generation facility that utilizes inverters to convert Direct Current to Alternating Current for delivery to the utility.

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

Interconnected Generation - Any generation that is designed to operate in parallel with the District's electric system for more than two seconds is considered to be interconnected and must meet the technical requirements for an interconnected generator.

Interconnection Facilities Study – The interconnection facilities study is the third and final study in the interconnection study process for generation interconnections. The purpose of the study is to provide the applicant with a comprehensive view of potential infrastructure upgrades and costs required to interconnect with the District.

NERC - North American Electric Reliability Corporation

New Large Load Policy – The PUD, as a not-for-profit entity, strives to ensure equity in costs between customers. As such, costs incurred by the utility to build facilities to serve large new loads are paid in advance by the applicant, then repaid as a demand credit over ten years. This policy describes the cost allocation between the applicant and the utility for construction of any upgrades that must be completed in order to accommodate the interconnection of new loads above 2.5 MVA, as well as demand credit schedules. In the SIS, a detailed estimate is provided for the construction and specifies costs paid by the applicant and by the utility.

SCADA (Supervisory Control and Data Acquisition) - A system of remote control and telemetry used to monitor and control the electric system.

Single Point Loads – A load with a single point of interconnection with the District which is owned by one customer.

System Impact Study – The second study in the interconnection study process. The purpose of this study is to provide the applicant with detailed effects to be expected due to operation of the generation or interconnection of load and a good-faith, non-binding cost and construction timeline estimates for system mitigations.

Utility Tie Breaker – A breaker located at the point of interconnection which connects the project and the utility's electrical system.

Voltage Regulation - The difference between expected maximum and minimum voltage at any particular delivery point. The voltage regulation limits are expressed as a percent of the nominal voltage and are defined for both normal and contingency conditions.

Voltage Fluctuations – Voltage fluctuations are rapid changes in voltage that occur over a time period of 1 sec or less.

Temporary Overvoltage - Temporary over-voltages can last from seconds to minutes, and are not characterized as surges. These over-voltages are present during islanding or faults.

WECC – Western Electricity Coordinating Council

2 Interconnection Process

These guidelines contain a procedural overview along with technical requirements for customers seeking interconnection of new generation resources, transmission lines, and large loads (end-user facilities) onto the Public Utility District No. 1 of Snohomish County (“District”) transmission ($\geq 100\text{kV}$) electric system. This procedure also applies to existing projects looking to make a qualified change. The procedural overview (in Section 2.3) outlines the study process that applicants are required to complete as well as basic information on cost allocations. Contractual matters, such as costs, ownership, scheduling, and billing are not the focus of these requirements and will be addressed by Key Accounts in a related part of the process. The technical requirements outlined in this document are in place to ensure the safe operating integrity and reliability of the District-owned electric system.

This document states the minimum requirements for the safe and reliable operation of the customer-owned generating facility that will be connected and operated in parallel with the Snohomish County PUD (District) electric system. The study process required before interconnecting with the District’s system is also outlined in this document. Physical laws that govern the behavior of electric systems do not recognize boundaries of electric facility ownership. Therefore, the electric power system must be studied, without regard to ownership, to develop a properly designed interconnection that is compatible with the future electric system as well as present conditions.

For any interconnection with the District electric system or qualified change, the District should be contacted as early as possible.

2.1 Overview

The interconnection process typically begins with the applicant submitting the application and requesting that the District perform a Feasibility Review for the proposed project. During the Feasibility Review, the District evaluates each interconnection request individually, in the order that completed applications were received, and identifies high-level impacts to the District electric system. The system studies and cost estimates are not included in the Feasibility Review process.

Following the Feasibility Review, if the applicant decides to proceed, the District will conduct a System Impact Study. This study will analyze the impacts to the District’s system and determine the mitigations required to minimize any negative impacts to the District’s system. In the System Impact Study, the District will provide a good-faith estimate of cost and time to construct for the mitigations required. If the project is determined to impact neighboring facilities, a “Joint Study” with other utilities to address any potential impact to the reliability of the bulk electrical system may also be needed. This may require that other entities perform their own studies and impose their own fees and schedules. Interconnection requirements are then provided back to the applicant. Interconnection requirements are intended to comply with NERC Reliability Standards FAC-001 and FAC-002.

2.2 Project Study Requirements

Specific thresholds determine the level of study required for each project. The thresholds for generator and large load projects proposed for connection to the District’s system at either distribution or transmission voltage are outlined below.

Generation

The District has a variety of programs covering the interconnection of generation of various types and sizes to its system. These programs include Net Metering, Net Billing, and Parallel Interconnected Generators. For more information about these programs, please check out the SnoPUD website or contact

Key Accounts. Commercial agreements aside, the technical requirements for these programs are all designed to ensure the operating integrity and reliability of the system.

Generation		
Type	Size	Study required
Renewable (inverter-based)	≤ 100 kW	Net Metering evaluation - ESR 6
Fuel cell, cogeneration, or renewable (inverter-based)	≤ 200 kW	Net Billing - similar to ESR 6 evaluation
Any type	> 200 kW	Both District and BPA interconnection studies are required

Renewable generation connecting to the system through UL 1741 inverters may be approved in expedited fashion as described in Electrical Service Requirements Chapter 6 ([Section 6 Generation Interconnection](#)).

Rotating-machine generation projects not connected through UL 1741 inverters are evaluated based on the machine parameters and the system to which connection is proposed.

All projects connecting generation facilities 200 kW and greater to the system require an interconnection study (see Section 2.3), which will determine whether the project will connect at distribution voltage to a shared feeder, a dedicated feeder, or at transmission voltage. In addition, a Bonneville Power Administration (BPA) interconnection study is required. Because BPA acts as the Balancing Area Authority and Planning Coordinator for the District, this study can identify whether the project will require ancillary services from BPA.

Loads

Load additions less than or equal to 2.5 MVA do not require an official study. For loads greater than 2.5 MVA, where capacity is available to serve the load, an interconnection study is not required, and the project can proceed following payment of Amp fees. Available capacity and the need for study will be determined in the Feasibility Review.

If capacity is not available to serve a load greater than 2.5 MVA, a System Impact Study is conducted, and costs are allocated in accordance with the District’s New Large Load Policy. The study will determine whether the load will interconnect at distribution voltage to a shared feeder, a dedicated feeder, or at transmission voltage.

At the present time, new loads up to 9.9 MVA can be interconnected without a power supply review. Loads at 10MVA or above will require an additional power supply analysis.

Loads		
Size	Study required	Typical feed
≤ 2.5 MVA	No	Shared feeder
> 2.5 MVA with existing capacity	Study is not required if existing capacity is available to serve the requested amount of load	Shared feeder
> 2.5 MVA without existing capacity	If existing capacity is not available to serve the requested amount of load	Determined by study results

2.3 Study Process Summary

The Interconnection Study process has up to three phases. The first phase is the Feasibility Review which is followed by the System Impact Study (SIS) and, finally, the Interconnection Facilities Study (IFS) for generation projects and New Large Load Policy (NLLP) for load projects. The purpose of the three phases is to determine how proposed interconnections will affect the District’s system and what system upgrades and improvements must be made to support the interconnection. Once the study process has been completed, a report detailing interconnection requirements are provided back to the applicant.

Interconnection requirements are designed to comply with NERC Reliability Standards FAC-001 and FAC-002 as applicable.

Applicants should contact the District as early in the planning process as possible for any potential generation, line, or large load projects within or adjacent to the District system and/or where the output will enter the District Electric System. The applicant shall not make their own assumptions about the final location, voltage, or interconnection requirements. The District may have to add or modify its distribution or transmission system substantially before connecting a customer-owned facility. An Interconnection Study is used to determine the required interconnection facilities and modifications to accommodate the customer-owned facilities. This study may also address transient stability, voltage stability, losses, voltage regulation, harmonics, voltage flicker, electromagnetic transients, machine dynamics, Ferro-resonance, metering requirements, protective relaying, substation grounding, and fault duties as applicable. The applicant will provide the District with sufficient information for adequate system study.

Assessments and studies shall comply with the latest applicable NERC Reliability Standards and WECC System Performance Criteria.

The District shall conduct stability studies or reserve the right to select a non-District competent third-party professional engineering services to assist in transient stability impact studies using WECC-approved models and format.

A link to a flow chart illustrating the “Customer Owned Generation – Interconnection Application Process” can be found on the District’s Public website: [Connecting Generation - Snohomish County PUD](#)

Similarly, a link to a flow chart illustrating the “Large Load – Interconnection Application Process” can be found on the District’s Public website: [Connecting Large Loads - Snohomish County PUD](#)

2.3.1 Phase 1: Feasibility Review

- Time Frame: ~1 month
- Fee: \$5,000
- Required Materials: For Generation or Line: Form 6-1
For Load: New Service Questionnaire (NSQ) Form

The Feasibility Review begins once the applicant submits the interconnection application signed by the end-user, pays the Feasibility Review fee, and provides all project data requested by the District. The specific data requirements vary depending on the type of interconnection. The Feasibility Review process and timeline commence only after the District confirms receipt of all required project data from the developer.

The goals of this review are to identify basic parameters of the interconnection, to determine which processes and technical requirements apply, and to provide a non-binding outline of key equipment and work which may be needed. Basic parameters of the interconnection might include availability of three-phase service at the project site if required, circuit load capacity, annual circuit and/or line section peak and minimum loads, available short-circuit current, any existing system constraints, and protective devices affected by the proposed installation. Examples of key equipment and work which may be identified include transformer upgrades, or the requirement of a new feeder or a dedicated substation. A determination of whether the applicant's generation is classified as parallel or non-parallel operation with the District's electric system will also be made. For single point loads $\geq 10\text{MW}$, the feasibility review will also include a discussion about power acquisition options available to the applicant.

The results of the Feasibility Review will be presented to the applicant during the feasibility review meeting. This meeting will be scheduled with the applicant by the District within 10 days of receiving the application. After the feasibility review meeting the applicant will then have 30 days to decide whether to continue with the interconnection study process or withdraw. If the District is not informed of the applicant's intent to proceed by day 30, the District will send the customer a notice that their project has been deemed reviewed. If a notice to proceed is provided in the following 5 business days, the project will maintain its position in the queue otherwise the project will be permanently withdrawn from the queue.

At the agreement of both the District and the applicant, the Feasibility Review may be waived, and the applicant can proceed directly to the System Impact study.

2.3.2 Phase 2: System Impact Study (SIS)

- Time Frame: ~5-8 Months
- Fee: \$10,000+
- Required Materials: For Generation/Line: Form 6-2, Project Data
For Load: Project Data

If the applicant has decided to proceed with the study process after the Feasibility Review or if the Feasibility Review has been waived, the interconnection project will proceed to the System Impact Study (SIS). Before the SIS begins, the applicant must provide the District Form 6-2 and/or the requested project data. Once the required materials have been received and reviewed, the District will tender the applicant a System Impact Study Agreement as well as an Additional Data Request if data in addition to what has been provided is required. Once the applicant has signed the System Impact Study Agreement, submitted the requested data, and paid the fee, the SIS will begin.

The System Impact study may include steady state power flow, short circuit, and transient stability analyses as appropriate depending on the project. The System Impact Study will be performed using utility industry software modeling tools.

The technical analyses begin with Western Electricity Coordinating Council (WECC) approved base cases. The model is then updated with the latest system configuration, generating resources, and projected loads. Planned maintenance outages of generation and transmission facilities matching the time frame of the applicant's service request shall also be modeled in the base case(s). To evaluate the electrical system impacts, the District employs the District's Transmission General Planning Guidelines as well as Transmission Planning criteria from the North American Electric Reliability Corporation (NERC) standard TPL-001, and system performance criteria from WECC. Short circuit analysis is also performed and benchmarked against District standards. For inverter-based resources, EMT models will be required. The EMT model's dynamic response must align with the behavior represented in the positive sequence model submitted to the District. Studies performed by the District include both near-term (years 1 through 5) studies and longer-term planning horizons.

Studies identify operation outside the acceptable ranges of facility rating limits, voltage stability limits, and transient stability limits among others. Mitigations (solutions) are proposed which may include facility additions, upgrades, and other modifications. The applicant may be responsible for all or part of the cost of the mitigation. Mitigations identified by the District must be in place before the proposed interconnection project can be put into service.

The SIS report will identify detailed effects to be expected due to operation of the generation or interconnection of load. The SIS report will also provide a high-level summary of technical requirements that may apply for the interconnection. A good-faith cost and construction timeline estimates for system mitigations required for interconnection will also be provided in the report. The results of the SIS study will be presented to the applicant initially in a draft SIS report. The applicant will have 30 days to provide comments back to the District about the report. The District will then finalize the report and send a final draft back to the applicant.

The results of the SIS will also be presented to the applicant during the SIS review meeting. This meeting will be scheduled with the applicant by the District within 10 days to occur within 30 days of the SIS completion. Any questions or comments about the draft report can be discussed during this meeting. After the final draft is sent, the applicant will then have 90 business days to decide whether to continue with the interconnection process or withdraw. If the District is not informed of the applicant's intent to proceed by day 90, the District will send the customer with a notice that their project has been deemed withdrawn. If a notice to proceed is provided in the following 5 business days, the project will maintain its position in the queue otherwise the project will be permanently withdrawn from the queue.

2.3.2.1 Neighboring Systems

Because of the networked nature of the transmission system, interconnection projects sometime can affect neighboring systems. If the District identifies that a project affects a neighboring entity's system, the District will cooperate with the affected entities to identify solutions acceptable to all parties. This may require that affected entities perform their own studies and impose their own fees and schedules. More information about this coordination process can be found in Section 2.8.

In addition, if District studies show that interconnection projects are affected by neighboring transmission limits, the District will contact the neighboring transmission provider to verify that limit. If the

neighboring transmission provider verifies the limit, the District will honor the external limit and will notify the applicant.

2.3.3 Phase 3 – Generation/Line: Interconnection Facilities Study

Time Frame: ~5 – 8 Months

Fee: \$50,000+

Required Materials: If applicable, Additional Data

If the applicant decides to proceed with the study process after the System Impact Study, the interconnection project will proceed to the Interconnection Facilities Study (IFS). To begin the IFS process, the District will tender the applicant an Interconnection Facilities Study Agreement as well as an Additional Data Request if the District has identified additional input data is needed. Once the applicant has signed the Interconnection Facilities Study Agreement, submitted any requested data, and paid the fee, the IFS will begin.

The IFS will identify a detailed cost estimate based on a preliminary design for the project. This study will also include a detailed construction timeline, any applicable electrical switching required, any controls and communications equipment required, any necessary protection equipment required, and, for generation projects, any essential generation controls. The IFS will provide the applicant with a comprehensive view of potential infrastructure upgrades and costs required to interconnect with the District.

The results of the IFS will be presented to the applicant during the IFS review meeting. This meeting will be scheduled with the applicant by the District within 10 days to occur within 30 days of the conclusion of the IFS. After the IFS review meeting the applicant will then have 30 business days to decide whether to continue with the interconnection process or withdraw. If the District is not informed of the applicant's intent to proceed by day 30, the District will send the customer with a notice that their project has been deemed withdrawn. If a notice to proceed is provided in the following 5 business days, the project will maintain its position in the queue otherwise the project will be permanently withdrawn from the queue.

Applicants who have a high degree of certainty of implementing a project may request to combine the SIS and the IFS into a single study. This request will be granted at the District's discretion. This can reduce the total time required for the District to complete its portion of the study phase of the project.

2.3.4 Phase 3 – Large Load: New Large Load Policy

Time Frame: Project Dependent

Fee: Project Dependent

Required Materials: If applicable, Additional Data

If the applicant decides to proceed with the study process after the System Impact Study, the large load project will proceed to the New Large Load Policy (NLLP). To begin the NLLP process, the District will tender the applicant an NLLP contract as well as an Additional Data Request if the District has identified additional input data is needed. Once the applicant has signed the NLLP, submitted any requested data, and paid any required fees, the first task order of the NLLP will begin.

The first task order in the NLLP will identify a more refined (than the SIS) project cost estimate based on a preliminary design for the project. This task order will also produce a more refined construction timeline. Task Order 1 of the NLLP will provide the applicant with a comprehensive view of potential infrastructure upgrades and costs required to interconnect with the District.

The results of Task Order 1 will be presented to the applicant during a review meeting. This meeting will be scheduled with the applicant by the District within 10 days to occur within 30 days of the conclusion of Task Order 1. After the review meeting the applicant will then have 30 business days to decide whether to continue with the interconnection process or withdraw. If the District is not informed of the applicant's intent to proceed by day 30, the District will send the customer with a notice that their project has been deemed withdrawn. If a notice to proceed is provided in the following 5 business days, the project will maintain its position in the queue otherwise the project will be permanently withdrawn from the queue.

Applicants who have a high degree of certainty of implementing a project may request to combine the SIS and Task Order 1 into a single study. This request will be granted at the District's discretion. This can reduce the total time required for the District to complete its portion of the study phase of the project.

2.3.5 Phase 4: Interconnection Agreement

If the applicant decides to proceed with the interconnection after the study process is complete, customer-owned generation/line interconnection project will proceed to an Interconnection Agreement. Large load projects will continue with the NLLP process. The District's Key Accounts team will coordinate these processes.

2.4 Required Data

Data required for the interconnection study process varies from stage to stage as well as project type. The forms used to submit technical data can be found on the District's Public website (links in Section 2.3) or will be provided by submitting a written request to the contact provided in Section 6. Below is an outline of which forms should be used for various scenarios.

Feasibility Review	Form 6-1 for Generation/Line New Service Questionnaire for Load
System Impact Study	Form 6-2 for Generation/Line and Project Data for All
Interconnection Facilities Study	If applicable, Additional Data
New Large Load Policy	If applicable, Additional Data

When completing the forms, the District will work with the applicant to answer any questions. If forms are not filled out to the District's standards, additional data requests will be made of the applicant for the missing or incomplete information before the study begins.

When applicable, data requested from the applicant shall comply with the "WECC Data Preparation Manual." This is a procedure from WECC for reporting and submitting data for Interconnection-wide cases for power flow, short-circuit, and dynamic data. These requirements include, but are not limited to, fuel type, maximum MW output, generator terminal voltage, transformer high-side and low-side voltages, generator MVA, generator nominal power factor, and dynamic data. The District only accepts models listed in the "WECC Approved Dynamic Model Library". WECC-approved cases only contain modeling data that have been reviewed and accepted for operation and planning base cases. Compliance with this WECC manual also ensures compliance with the District's MOD-032 Modeling Procedure which can be found on the District website.

The District will protect proprietary and confidential information as required or permitted by applicable law concerning requests for applicant transmission and distribution system information.

A selection of the information which may be requested in the data submission forms includes the following:

1. Electrical one-line diagrams, type of generation (natural gas, hydro, wind, geothermal, etc.), proposed nameplate ratings, site location maps, site plan, high-voltage system routing, and a description of the proposed connection to the District system.
2. All available generator and transformer data. Note that the machine portion of these data generally means synchronous machine data. Other types of generators (such as induction generators or DC generators with inverters) are handled on a case-by-case basis.
3. Validated models and data for power flow and dynamic (stability) simulation. This validated data can be specified as a requirement of commissioning tests. The data requirements include:
 - a. Generator reactive power limits (generator PQ capability curve) addressing effects of all control, protection, and operating/equipment limits that can restrict reactive power output,
 - b. Exciter, including power system stabilizer and other limiters, and high side voltage controls,
 - c. Prime mover, governor, overfrequency protection, and underfrequency protection,
 - d. Generator subtransient, transient, and steady-state reactance and time constant data, and
 - e. Generator step-up transformer capacity, impedance, and winding connection data.
4. A description of the anticipated operating profile of the customer-owned generating facility, including the peak monthly megawatt (MW) output of the customer-owned generating facility, expected period of operation, and maintenance periods.

2.5 Cost Allocation Policy

Contractual matters, such as costs, ownership, scheduling, and billing are not the focus of these guidelines. This section is provided as a general overview of how interconnection costs are understood at the District. For more detailed information about cost allocation please contact the District's Key Accounts team (keyaccounts@snopud.com).

The PUD is a not-for-profit, consumer-owned utility that provides electrical service at cost to its ratepayers. The costs of interconnection necessary to deliver service to each applicant are assessed in the interconnection process outlined above. These costs include all the costs of study, engineering, inspection, connection, switching, metering, transmission, distribution, safety provisions, equipment to be owned by the District, and administrative costs incurred by the District directly related to the installation and maintenance of the physical facilities necessary to permit the customer-owned generating facility operation. All costs will align with the District's customer Service Regulations for Electric Service guide.

For new loads equal to or greater than the New Large Load Policy threshold (2.5MW as of 2021), the New Large Load Policy will dictate how the costs of interconnection are split between the applicant and the District. The New Large Load Policy works to ensure that customers causing the District to incur costs associated with large load additions cover such costs. Line Extension Policy Fees may apply in addition to fees associated with New Large Load Policy.

For new loads less than the New Large Load Policy threshold (2.5MW as of 2021), the applicant will typically have to pay line extension and amps fees as applicable with the rest of the interconnection costs being borne by the District.

2.6 Qualified Change Definition

Certain types of changes to an existing facility or a previously studied facility require that new interconnection studies be performed. These changes are called "qualified changes" and are defined by BPA acting as the District's Planning Coordinator. The BPA definition of qualified change can be found in

BPA's "Technical Requirements for Interconnection to the BPA Transmission System" (in the 4/3/25 revision on pg 88 & 89).

Generally speaking, a qualified change is anything that would change the electrical parameters of the project such as differently rated equipment, equipment with significantly different electrical parameters, significant increase in load demand, etc.

If a project is identified to fall into the category of a qualified change, the project will need to be restudied in the same manner as a new interconnection project. This re-study will happen at the applicant's cost and the study timeline will reset once the project re-study begins. The re-study will also occur after any system impact studies that have been received in the interim are completed.

The District is required to study "materially modifying existing interconnections of generation, transmission or electricity end-user Facilities" connected to its BES system by NERC FAC-002.

2.7 Related Requirements and Policies

In addition to the technical requirements provided in Sections 3 and **Error! Reference source not found.** of this document, proposed projects must also comply with other District and industry standards as applicable. The latest version of each standard should be referenced. A summary of these standards and codes is outlined below.

All Projects

- National Electrical Code
- National Electrical Safety Code
- North American Electric Reliability Council Standards
- Western Electricity Coordinating Council Standards
- Washington State Safety Standards
- District Electrical Service Requirements
- District Construction Standards

Generation

- IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems, ANSI/IEEE Std 1001
- District Generating Facility Planning Requirements as applicable
- BPA's Technical Requirements for Interconnection to the BPA Transmission Grid STD-N-000001 -- sections 6,9,10 and 12.
- Standard for Interconnecting Distributed Resources with Electric Power Systems, IEEE P1547, and UL 1741
- IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems, IEEE Std 2800
- IEEE Guide for Protection Systems of Transmission-to-Generation Interconnections, IEEE Std C37.246

The primary District standard is the Electrical Service Requirements manual which contains policies, standards and general requirements for providing overhead and underground distribution service to District customers. For all interconnection requests, the applicant shall have the responsibility of reading and understanding the Electrical Service Requirements document, available from Customer Engineering or from the District's public web page.

The District reserves the right to require the customer to provide at the customer's expense corrections or additions to existing facilities in the event of modification of government or industry regulations and standards

2.8 Coordination with External Entities

The District shall, as required and necessary, coordinate with other neighboring entities if any proposed and/or implemented new or modified facilities interconnected to the District's Electric System may impact their system. This coordination process shall begin with the District reviewing each project to identify potential impacts to neighboring entities. Any entities identified as potentially impacted will be notified of the project at the earliest possible stage of the project. Additionally, this notification shall include a statement informing the affected entity that the proposed facility's Balancing Authority would be BPA. This notification will occur in writing and will request the entity review the project for impacts to their own system and notify the District of any impacts identified. In the District's initial notification, confirmation of receipt shall be requested. The applicant of the study will also be notified and instructed to contact the affected neighboring system to pursue further study with that entity.

The District complies with the process within the NERC Facility Standard FAC-002 for studying the impact of new or modified facilities on others. Furthermore, the District reviews, revises, and submits WECC base cases with projects under construction, budgeted, and planned for in the current capital construction plan. Below is the routine, annual data transmission and information exchange procedure with others to ensure correct data model exchange for use in system impact studies:

1. The District submits annual system data to Western Power Pool as the Northwest Area Coordinator for a final submittal to WECC. The system data shall include but not be limited to the projected loads, system topology, and generation resources used in its planning studies.
2. The District will submit as needed any generation dynamic characteristic modifications to WECC. The District will coordinate all dynamic data submittals to WECC.
3. Technical steady state and dynamic data used for District planning studies will be made available to other regional entities subject to appropriate non-disclosure, including the District planning base cases.
4. The District transmission system planning base-case model is to be updated annually and includes the latest updates of generation, and customer and transmission connections.
5. The applicable District General Planning Guidelines, Electric Service Requirements, and Customer Service Regulations will also be made available.
6. Transmission system steady state and dynamic data will be stored in a System Planning & Protection share drive. Data will not be located on a public share drive.
7. Information is exchanged in regional and sub-regional planning forums including WECC, BPA, WPP, and ColumbiaGrid. These listed entities have procedures to make planning information available subject to appropriate non-disclosure.

2.9 Ancillary Services

All loads, transmission, and distribution facilities connected with or a part of the District's electric system are part of the BPA's Balancing Authority (BA). The host BA provides critical ancillary services, including load regulation, frequency response, operating reserves, voltage control from generating resources, scheduling, system controls and dispatching service, as defined by FERC, or their successors. All new connections to the District's electric transmission system also require review for a transmission contract with the BA.

2.10 District's Protection Philosophy

The District is committed to providing excellent service to all of its customers. A critical part of accomplishing this goal is a robust protection system. The District's protection requirements address the following objectives:

- Ensure the safety of the general public, District and other utility personnel.
- Prevent property damage to the general public, District and customers.
- Minimize adverse operating conditions affecting the District and customers.
- Adhere to District standards and requirements.
- Comply with NERC and WECC Standards subject to enforcement.
- Comply with industry standards
- Witness testing of all protective systems will be required before the District allows commissioning and parallel operation.

Any new customers interconnecting with the District's system must take protection considerations into account. The protection schemes and equipment necessary to integrate the new connection must be consistent with District practices, standards, and guidelines. The protection system must be designed to reliably detect faults or abnormal system conditions and provide an appropriate means to isolate the equipment from the system automatically. Special relaying practices may also be required for system disturbance, such as undervoltage or underfrequency detection for load shedding or reactive device switching.

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

Each request for interconnection will be handled individually, and the District will make the final determination of the protective devices, maintenance and operation requirements, communications and control requirements, and system modifications and/or additions required. When applicable, the interconnected facility's periodic maintenance, testing, and validation are required and must be consistent with NERC/WECC standard guidelines. The Applicant shall provide equipment specifications, protection arrangements, and design drawings to the District for review and written approval prior to installation. The District will work with the customer to achieve an installation that meets the requirements of both the customer and the District.

2.11 Technical Requirements - General

The technical requirements identified in this document are not intended as a design specification or an instruction manual and the information presented is expected to change periodically based on industry events, evolving standards, and internal and external changes to the District's electric system. Technical requirements stated herein are consistent with the District's current internal electric facility planning guidelines and practices for system additions and modifications. These requirements are intended to be in full compliance with the North American Electric Reliability Corporation (NERC), and Western Electricity Coordinating Council (WECC) requirements and also to be consistent with the general principles and practices of the Institute of Electrical and Electronics Engineers (IEEE) and American National Standards Institute (ANSI) if applicable. To the extent that the codes, standards, criteria and regulations are applicable, the new or modified facilities shall be in compliance with those standards and practices.

The technical requirements contained herein generally apply to all new or expanded facilities, regardless of type or size. If a requirement is only applicable to a certain class of interconnection (voltage, generation or load, location, etc.), the application of the requirement will be noted.

The customer-owned facility and its interconnecting facilities must not degrade the safe operation, integrity, and reliability of the District's system. The District will make the final determination if the District's facilities are properly protected before an interconnection is energized.

Any questions regarding technical requirements stated in this document should be directed to System Planning and Protection Group.

3 Technical Requirements – Transmission System

These technical requirements outline the guidelines that customer-owned facilities interconnecting with the District's system at 100kV or greater voltages must adhere to. These facilities include generation facilities, transmission facilities, and load (end-user) facilities. Facilities connecting with the District's high-voltage transmission system typically require a new District substation in accordance with District Guidelines.

3.1 Load (End-User) Facilities and Line Facilities

These are the interconnection requirements that load (end-user) facilities and line facilities must meet when interconnecting with the District's transmission system. Some of these standards are operational requirements the District must meet when proposing mitigations for an interconnection project.

3.1.1 Voltage

Specification 1: Customer-owned facilities are allowed a maximum voltage of 1.05pu at the POI.

Specification 2: Customer-owned facilities are allowed a minimum voltage of 0.95pu at the POI.

3.1.2 Power Factor

Specification 1: Customers-owned facilities interconnecting with the transmission system shall maintain a power factor between 0.95 lagging/leading.

Specification 2: Unless otherwise specifically agreed, the District shall not be obligated to deliver Electric energy to the customer at any time at a power factor below 0.75 (refers to Average overall power factor for each individually metered service).

3.1.3 Phase Unbalance

Voltage unbalanced is defined as the ratio of the negative sequence voltage divided by the positive sequence voltage expressed as a percentage (BPA Interconnection Technical Requirements).

Specification 1: A single facility (interconnection) should not cause a voltage unbalance greater than 1.3%. (as required by BPA)

3.1.4 Underfrequency Load Shedding

Power system disturbances, such as faults and forced equipment outages, can expose the system to oscillations in voltage and frequency. It is important that transmission and generation remain in service for dynamic oscillations that are stable and damped. Large-scale blackouts can result from the excessive loss of generation, outage of a major transmission facility, or load rejection during a disturbance. In order to prevent such events, WECC has implemented a region-wide underfrequency load shedding (UFLS) coordinated plan: the WECC Off-Nominal Frequency Load Shedding Plan. The District participates in the

Northwest Power Pool sub-area Coordinated Plan, which is one of the three options offered by the WECC coordinated plan.

Specification 1: Depending on the type and location of any new customer load, the customer may be required to participate in this plan.

3.1.5 Facilities

Specification 1: Customer facilities connecting with the District's high-voltage transmission system typically require a new District substation in accordance with District Guidelines.

3.2 Load Facilities Protection

For the minority of load customers who own and operate their own substation which interconnects with the District's system, the District will coordinate protection and protection requirements with the customer. General protection requirements can be gathered from Section 3.4.

3.3 Generation Facilities

These are the interconnection requirements that generation facilities must meet when interconnecting with the District's transmission system; some of these are operational requirements that the District must meet when proposing mitigations for an interconnection project.

3.3.1 Voltage

Specification 1: A voltage schedule will be mutually developed between the District and the customer, which will be coordinated via time changes developed by the WECC for such coordination purposes. Voltage schedules are necessary to maintain optimal voltage profiles across the regional transmission system. Optimal profiles minimize transmission of reactive power and preserve flexibility in use of reactive power control facilities.

Specification 2: The voltage at the POI shall not deviate more than 1% due to rapid fluctuations at the generation input.

3.3.2 Real Power

Specification 1: All generation facilities with an installed capacity larger than the POI limit shall install back up automation controls or directional relaying to ensure POI limit is not exceeded.

Specification 2: If facility exceeds 102% of POI MW limit for the shorter of 30 sec or 2 control cycles, the controls and relaying shall ramp down the facility to POI limit.

Specification 3: The District has the authority to disconnect the facility at POI if the POI limit is exceeded. Reconnection shall not occur unless reasons for failed controls are communicated or test evidence of corrections is provided.

3.3.3 Reactive Power

Specification 1: Each entity shall provide for its own reactive power requirements, at both leading and lagging power factors unless otherwise specified by the District.

Specification 2: All generation facilities shall be capable of providing reactive power as defined by BPA's Minimum Plant Reactive Power Capability. For normal voltages, POI voltages inside a defined voltage band around the scheduled voltage, Minimum Reactive Power Capability is defined as $\pm 33\%$ of the plant's nameplate MW in dynamic MVARs at the POI (BPA Definition).

Specification 3: Facilities utilizing inverters which are unable to meet reactive capability requirements when actual power output is 10% or less may request study to determine if reduced reactive capability is permissible.

Specification 4: Minimum Plant Reactive Power Capability may reach zero at $\pm 4\%$ of the scheduled voltage.

Specification 5: Inverters should not use settings to limit reactive power output.

3.3.4 Voltage Control

Specification 1: Generation projects interconnecting with the District's system are expected to have voltage control at their POI.

Specification 2: During normal operation, POI voltage shall remain within $\pm 1.5\%$ of the scheduled voltage.

Specification 3: All generation facilities are required to have Automatic Voltage Regulation (AVR).

Specification 4: The facility's AVR must be operated in voltage control mode while connected with the District's system.

Specification 5: The POI voltage must be controlled with a 2% reactive droop. (as required by BPA.)

Specification 6: The control systems must operate fast enough to react to changes in generation without the need for transmission-level control devices engaging.

Specification 7: Facilities should not violate voltage schedule or Minimum Reactive Capability when transitioning between control modes.

Specification 8: A power system stabilizer (PSS) shall be installed on every synchronous generator that is larger than 20 MVA, or is part of a complex that has an aggregate capacity larger than 75 MVA, and is equipped with suitable excitation systems as defined in paragraph 1a [of WECC Policy Statement on Power System Stabilizers, dated April 18, 2002]. (as required by WECC).

Specification 9: Synchronous generation facilities must operate this excitation system in automatic voltage control mode.

Specification 10: The customer is required to obtain automatic generation control (AGC) services from Load Control Area provider (BPA). The customer is required to install the equipment required for the Load Control Area provider to provide the service. *The District is not a Load Control Area provider and does not provide any AGC services.

3.3.5 Frequency Control

Specification 1: All generation facilities must have primary frequency response capability.

Specification 2: Prime mover control (governors and inverters) shall operate freely and with appropriate characteristics to regulate frequency.

Specification 3: The total governor deadband should not exceed $\pm 0.06\%$ ($\pm 36\text{mHZ}$) (as required by BPA.)

Specification 4: The active power step response time (time to reach 90% of total final response) of the frequency control should be the fastest response the facility can achieve and less than 5 seconds. This 5 second limit can be adjusted for physical system limitations.

Specification 5: Frequency deadband implementation recommended by NERC & BPA (see BPA Technical Requirements for Interconnection to the BPA Transmission Grid pg 28)

Note 1: Anything related to ancillary services is under the direction of BPA as District's Balancing authority. The BPA Technical Requirements for Interconnection can be referenced.

3.3.6 Energy Storage Requirements

Specification 1: Storage components state of charge and mode (charging or discharging) shall be communicated in real time by energy storage projects.

Specification 2: Energy storage projects shall be able to perform sequential trip to trip off part(s) of the project in increments if applicable.

3.3.7 Phase Unbalance

Voltage unbalanced is defined as the ratio of the negative sequence voltage divided by the positive sequence voltage expressed as a percentage (BPA Interconnection Technical Requirements).

Specification 1: A single facility (interconnection) should not cause a voltage unbalance greater than 1.3%. (as required by BPA.)

3.3.8 Harmonics

Specification 1: The voltage and current harmonic content of the customer-owned generating facility output must be below that level which would cause undue interference with other customer loads, other utilities, or District equipment.

Specification 2: The voltage and current harmonic content of the customer-owned generating facility output must be at or below the distortion limits outlined in IEEE 519.

3.3.9 Facilities

Specification 1: Customer generation facilities connected with the District's high-voltage transmission system typically require a new District substation in accordance with District Guidelines.

3.4 Generation Facilities Protection

The following sub-sections outline the protection requirements for generation facilities interconnecting with the District's 115kV system. The District will not assume any responsibility for protection of the applicant's equipment. Applicants are solely responsible for protecting their equipment in such a manner that faults, imbalances, or other disturbances do not cause damage to their facilities or result in problems for other customers or the District's Transmission Grid.

3.4.1 General Protection

Specification 1: The customer is fully responsible for the protection of their generators and all associated equipment.

Specification 2: The customer must provide protection for their equipment against failures, faults, and other disturbances originating from the District's system.

Specification 3: Prior to installation, the customer shall submit equipment specifications, protection schemes, and design drawings to the District for review and written approval.

Specification 4: All circuit breakers, disconnect switches, and other current-carrying equipment connected to the District transmission system must:

- Carry normal and emergency load currents,
- Withstand available fault currents without damage,
- Not limit the District’s power transfer capability, and
- Sustain the maximum continuous current during steady-state operation.

Specification 5: All fault interrupting devices must safely interrupt any fault current they may be required to clear.

Specification 6: All equipment applications shall comply with ANSI/IEEE C37 Standards. All inverter applications shall comply with IEEE 2800.

Specification 7: The customer is responsible for ensuring the proposed Generator protective relay settings coordinate with the District’s transmission protective relay settings. The District shall review the customer’s relay settings prior to their implementation and may verify them during witness testing.

3.4.2 Frequency Protection

Specification 1: Customer-owned generating facility shall comply with the WECC Off-Nominal Frequency Load Shedding Plan¹. Customer-owned generating facilities must have relaying protection that accommodates, as a minimum, underfrequency and over frequency operation for the specified time frames as outlined in Table 1.

Table 1: Generation Over/Under Frequency Operation Timeframes

Underfrequency Limit	Over Frequency Limit	Minimum Time
>59.4 Hz	<60.6 Hz	N/A (continuous operating range)
≤59.4 Hz	≥60.6 Hz	3 minutes
≤58.4 Hz	≥61.6 Hz	30 seconds
≤57.8 Hz		7.5 seconds
≤57.3 Hz		45 cycles
≤57.0 Hz	≥61.7 Hz	Instantaneous trip

Specification 2: The customer’s frequency relay settings shall be reviewed and approved by the District prior to start-up.

Specification 3: Frequency relays shall be microprocessor-based; electro-mechanical relays used for this function are unacceptable.

3.4.3 Voltage Protection

Specification 1: To prevent any hazardous operating conditions, the customer-owned generating facility shall be isolated from the District high voltage system for over/under-voltage conditions. However, Over/Under-Voltage relays shall be set in accordance with NERC PRC-024 to ride through temporary low or high voltages that can result from faults or transients on the Transmission system.

¹ <https://www.wecc.org/sites/default/files/documents/products/2024/Off-Nominal%20Frequency%20Load%20Shedding%20Plan.pdf>

Specification 2: Applicant over/under voltage relays shall be set in accordance with the trip setpoints listed in Table 2.

Table 2: Generation Over/Under Voltage Relay Settings

Voltage	Action
≥ 1.20 pu	Instantaneous no intentional delay before unit tripping
≥ 1.175 pu	0.2-second minimum delay before unit tripping
≥ 1.15 pu	0.5-second minimum delay before unit tripping
≥ 1.10 pu	1.0-second minimum delay before unit tripping
< 1.10 pu	4.0-second minimum delay before unit tripping
< 0.90 pu	3.0-second minimum delay before unit tripping
≥ 0.90 pu	4.0-second minimum delay before unit tripping

Specification 3: Voltage relays must have a dropout time no greater than 2 cycles

Specification 4: For extremely high voltages, the over-voltage relay shall operate fast enough (without any intentional delay) to prevent equipment damage.

3.4.4 Teleprotection

Specification 1: Generating facilities interconnecting with the District’s Transmission system shall be equipped with high-speed pilot protection schemes. Dedicated communication channels between the generating facility and the District’s remote line terminal(s) are required for this function.

Specification 2: The customer-owned generating facility shall install redundant multi-function microprocessor-based relays on lines interconnecting their facilities to the District Transmission system; those relays shall be compatible with the District’s relays at the line terminals remote to those generating facilities.

Note 1: If multi-functional, microprocessor-based generator protection relay is used; the customer is strongly encouraged to install one additional relay (backup relay) with the same protective functions and settings to ensure adequate protection in the event of a device or DC supply failure.

3.4.5 Breaker Duty

The addition of the applicant’s proposed project to the District’s system may increase the fault duty in the surrounding area. To mitigate the impacts of this increase in fault duty the impacted protection systems and devices may need to be upgraded.

Specification 1: The rated interrupting times in cycles typically required of circuit breakers on the District’s 115 kV system electric system is 3 cycles or less.

Specification 2: All existing high-voltage system apparatus (such as breakers, reclosers, fuses, current transformers, etc.) near the proposed generating facility shall be upgraded to handle fault duty increases as required.

3.4.6 Utility Tie Breaker(s) Owned by the Customer

Specification 1: The customer-owned utility tie breaker's protection shall reliably detect all faults on the District system and trip to isolate the generation from the fault.

Specification 2: The nominal breaker tripping time of 3 cycles shall be required to be used as a utility tie breaker.

Specification 3: The automatic isolation shall be done prior to the District transmission switching station breaker automatically reclosing and within a reasonable period of time, typically less than 2 seconds in the absence of direct transfer trip relaying.

Specification 4: The utility tie breaker must have an automatic synchronizing capability and also be able to handle a recovery voltage of 2 times rated voltage.

3.4.7 Disturbance Monitoring

Disturbances such as faults and abnormal operating conditions such as over/under frequency and over/under voltage may cause stress or damage to the customer-owned generating facilities. Investigating the root cause of these disturbances is essential in initiating the proper corrective action to address their effects. Additionally, depending on the size and operating voltage of these generating facilities, NERC disturbance monitoring Standards PRC-002 and PRC-028 may require the installation of Disturbance Monitoring Equipment (DME) and/or Dynamic Disturbance Recorders (DDR). Appropriate monitoring and recording equipment shall be installed at the generating facilities to assist in the investigation of system disturbances as well as meet Requirements of applicable NERC disturbance monitoring Standards.

Specification 1: The customer is responsible for any studies and investigations necessary to evaluate possible stresses or damages to their generating facilities, and for all corrective actions.

Specification 2: The customer shall install the appropriate DMEs and DDRs required to meet applicable NERC disturbance monitoring Standards.

Specification 3: The customer shall provide the District with Fault Recording (FR) and Sequence of Event Recording (SER) data upon request to help assist in the investigation of system disturbances impacting the District's electric system.

3.4.8 Automatic Reclosing

Both District distribution and transmission breakers are typically designed to perform automatic reclosing attempts after protective systems-initiated trips, to restore electric service. Auto-reclosing schemes must ensure that customer generating facilities are isolated from the District's system before automatic reclosing occurs, to prevent damage to the generation equipment.

Specification 1: Bus-side and line-side Potential Transformers (PTs) shall be installed at both the generating and the District's facilities' line terminals.

Specification 2: No automatic reclosing shall be allowed to the customer-owned generator breaker(s), unless a synchronism check with the District Transmission system is performed first.

3.4.9 Automatic Disconnection and Time-Delayed Automatic Reconnection

Specification 1: The customer-owned generating facility shall be designed to automatically disconnect and lockout when the District service is interrupted for any reason.

Specification 2: Automatic reconnection to the District distribution system shall be done on Hot-Bus/Hot-Line/Sync-Check at least 5 minutes after the automatic disconnection.

3.4.10 Surge Protection

Interconnecting new projects can change equipment duty, and may require that equipment be replaced or switchgear, communications, shielding, grounding and/or surge protection added to control voltage stress to acceptable levels. Voltage stresses, such as lightning or switching surges, may affect equipment duty. Remedies depend on the equipment capability and the type and magnitude of the stress.

Specification 1: In general, stations with equipment operated at 12.5 kV and above, as well as all power transformers, shall be protected against lightning and switching surges using surge arrester devices and/or shielding. Typically, this includes station shielding against direct lightning strokes, surge arresters on all power transformers, and surge protection with rod gaps or arresters on the incoming lines.

Specification 2: The customer shall be fully responsible for the protection of their generating facility from transient surges initiated by lightning, switching, or other system disturbances.

Specification 3: The District may identify additions required to maintain an acceptable level of the District system availability, reliability, equipment insulation margins, and safety.

Note: At voltages below 230-kV, modifications to protect the District system against customer-owned generating facility-generated switching surges are not anticipated. However, the system studies will be performed to identify the actual needs.

3.4.11 Lightning Surges

High voltage lines at voltages of 115-kV and higher which terminate at District switching stations may be required to meet additional shielding and/or surge protection requirements.

Specification 1: Incoming lines may be required to be shielded for ½ mile at 115-kV and 1 mile at 230kV.

Specification 2: Rod gaps may be required to be installed at 115kV and 230kV station entrances.

Specification 3: For certain switching stations at 115-kV and below, the District may require only an arrester at the station entrance in lieu of line shielding, or a reduced shielded zone adjacent to the station. These variations depend on the line length, the presence of a power circuit breaker on the high voltage side of the transformer, and the size of the transformer.

4 Generation Facility Requirements

This section contains requirements that all generation facilities must meet regardless of interconnection voltage.

4.1 Placement of Generating Facilities

To maintain the existing District high-voltage/distribution system's reliability, all customer-owned generating facilities shall meet the following specifications:

Specification 1: A customer-owned generating facility shall not be allowed within 10 feet (horizontal clearance) from any existing overhead electrical distribution (12.47kV) facilities and 20 feet (horizontal clearance) from any existing high-voltage (115kV and higher) electrical facilities.

Specification 2: Exhaust fumes shall not be directed to any existing overhead electrical facilities.

Specification 3: All feeders capable of serving the customer-owned generating facility (including redundant feeds) shall have all required interconnection relaying.

4.2 Visible Disconnect Switch Requirements

In order to safely perform work on the system, all generation interconnections must provide a disconnect device which isolates all sources of energy from the District's electric system, provides a visible open, and has provisions to allow District personnel to lock the switch open.

Specification 1: At the point of interconnection to the District system, an isolating device(s) shall be placed in an appropriate location, by agreement of the District and affected parties.

Specification 2: The isolation device(s) shall be equipped with a lockable mechanism for clearance tagging and provide a visible air gap in the isolated state.

Specification 3: The isolation device(s) must simultaneously open all phases (gang-operated).

Specification 4: The isolation device(s) must be accessible by the District and ultimately under the District Energy Control Center jurisdiction.

Specification 5: The isolation device(s) must be lockable in the open position by the District.

Specification 6: The isolation device(s) should not be operated without advanced notice to either party, unless an emergency condition requires that the device be opened to isolate the customer-owned generating facility.

Specification 7: The isolation device(s) must be suitable for safe operation under all foreseeable operating conditions.

Specification 8: Connected facilities shall not prevent the District from taking a transmission line or line section or other equipment out of service for operation or maintenance purposes.

Note: The District personnel may lock the device in the open position and install safety grounds for the following reasons:

- If it is necessary for the protection of maintenance personnel when working on de-energized circuits.
- If the customer-owned generating facility or the District equipment presents a hazardous condition.
- If the customer-owned generating facility or the District equipment interferes with the operation of the District system.

4.3 Generation Equipment Ratings

Specification 1: Generation facility ratings shall be based on limits provided by the generator manufacturer including the generator capability curve, with all associated equipment connected in series to the interconnection point.

Specification 2: Generators shall be rated at nameplate rating unless testing provides evidence to support an increase or decrease in capabilities.

Specification 3: The nameplate rating of an IBR facility shall be the minimum nameplate rating of either the inverter or the generation equipment.

Note: The District's transmission system has been developed with careful consideration for equipment ratings and follows the NERC Standard FAC-008.

4.4 Generation Starting as Induction Motor

In general, induction generators start as motors and also synchronous generators may be designed to start as motors.

Specification 1: The customer-owned generators starting as motors shall meet the motor starting requirements in the District Electrical Service Requirements and T&D Guidelines.

Specification 2: If starting requirements are not met, the District may require the customer to provide special or additional starting equipment.

4.5 Islanding

This District does not generally permit islanding conditions to exist except when the customer's generation is feeding their own load. The customer shall be fully responsible for protecting their own facility and District's facilities under islanding conditions. Operations for larger installations must be clearly detailed in an operating procedure signed by the customer and the District.

If generation is capable of operating in parallel with other District customers in an unintentional island, additional protection and control measures will be needed.

4.6 Right to Disconnect

The District reserves the right to discontinue or interrupt the customer-owned generation to correct any system emergency condition, outage, required system maintenance, or equipment failure.

4.7 Inverter Performance Requirements

IBR resources interconnecting with the District's system must meet industry standards of performance.

Specification 1: IBRs interconnecting with the District's transmission system must adhere to IEEE 2800.

Specification 2: IBRs interconnecting with the District's transmission system must adhere to IEEE 1547.

Specification 3: All IBRs interconnecting with the District's system, regardless of interconnection voltage, must adhere to UL 1741.

5 General System Details

This section contains various requirements that facilities must meet regardless of interconnection voltage.

5.1 Grounding Requirements

Specification 1: The applicant's facilities must be designed in accordance with good utility practice, IEEE Std. 80, and the National Electric Safety Code or National Electric Code, as applicable.

Specification 2: Studies must be performed to guarantee step and touch, as well as transferred, potentials are limited to safe levels in any area accessible to District Personnel.

Specification 3: The applicant's substation must have a ground grid that is solidly connected to all metallic structures and other non-energized metallic equipment. This grid shall limit the ground potential

gradients to such voltage and current levels that will not endanger the safety of people or damage equipment which are in, or immediately adjacent to, the site under normal and fault conditions.

Specification 4: If the applicant's substation's new ground grid is close to another substation, the two ground grids may be isolated or connected.

Specification 4a: If the ground grids are to be isolated, there must be no metallic ground connections between the two substation ground grids. Cable shields, cable sheaths, station service ground sheaths and overhead transmission shield wires or distribution ground conductors can all inadvertently connect ground grids.

Specification 4b: If the ground grids are to be interconnected, the interconnecting cables must have sufficient capacity to handle fault currents and control ground grid voltage rises.

Note: The integration of generation may substantially increase fault current levels at nearby substations. Modifications to the ground grids of existing stations may be necessary to keep grid voltage rises within safe levels. The System Impact Study will determine if modifications are required and the estimated cost. Any modifications will be performed at customer cost.

5.2 Equipment Ratings

Specification 1: If it is determined that customer's project causes existing District equipment ratings to be exceeded, the customer shall pay to have the equipment upgraded to handle these increases as required.

Specification 2: The design and ratings of the applicant's facilities shall not restrict the capability of the line(s).

Note: The District's transmission system has been developed with careful consideration for equipment ratings and follows the NERC Standard FAC-008.

5.3 Telecommunication Requirements

Telecommunications facilities will be installed to fulfill the control, protection, operation, dispatching, scheduling, and revenue metering requirements. They may be owned by the District, another utility, a service customer, or a third party. Any new required telecommunication facilities will be identified in the project requirements. Telecommunications facilities must be compatible with, and have similar reliability and performance characteristics to, telecommunications facilities currently used for operation of the District power system to which the new generation or loads will be connected.

5.3.1 Communication Requirements

This section contains requirements related to the remote operation of the Districts system and how interconnected facilities are connected into that operation.

Specification 1: Applicant must designate an official point of contact so that the District's and applicant's personnel can monitor, coordinate, and cooperate to ensure the reliable operation of the electric system during normal and emergency conditions.

5.3.1.1 Normal Conditions

Specification 1: The applicant shall not energize any de-energized District equipment unless the District System Operator specifically approves the energization.

Specification 2: The circuit the generating facility is connected to may be interrupted and re-energized by the District by means of a protective device which also performs automatic reclosing .

Specification 3: If the generation or load facility requires any type of telemetering, then voice communications to the District operator are also required. If the facility is not staffed with operators, alternative arrangements may be made subject to District approval.

Specification 4: A dedicated, direct automatic ring down trunk (or equivalent) voice circuit between the District control center and the operator of the generators or loads may be required for generators or loads of 10 MVA or greater.

5.3.1.2 Emergency Conditions

Emergency telecommunications conditions may develop that affect telecommunications equipment with or without directly affecting power transmission system facilities. Equipment redundancy and telecommunication route redundancy can protect against certain kinds of failure and telecommunications path interruption.

Note 1: If SCADA communication is lost and ECC is not able to verify condition of the facility, the entity may be isolated until manual control can be established.

5.3.2 Dedicated Communications Link for Pilot Relaying

Specification 1: The signal transmission delay caused by a communications link and all associated communications equipment shall not exceed 15 milliseconds. The District prefers a fiber optic communications link, but other types of communications links may be acceptable pending approval by the District.

5.3.3 Dedicated Communications Link for SCADA

To ensure safety of working personnel and prompt response to system abnormalities, the District shall be allowed to know the status of certain breakers (e.g., utility tie breaker, interconnection breaker, and generator breaker(s)) and the real & reactive power flow at the generator breakers and at the District primary meter.

Specification 1: A dedicated communications link for SCADA shall be required at certain breakers (e.g., utility tie breaker, interconnection breaker, and generator breaker(s)).

Specification 2: A Remote Terminal Unit (RTU) shall be installed at the generating facility and it shall be able to open and close the interconnection breaker remotely. In general, a District-owned local Remote Terminal Unit (RTU) shall be installed at the customer-owned generating facility to perform certain control and monitoring functions as specified.

5.3.4 General Telemetering Requirements

The District System Operations Center requires telemetry data for the integration of new generation resources. This typically consists of the continuous telemetering of kW and kVAr quantities and hourly transmission of the previous hour's kWh and kVArh from the customer-owned generating facility to the District System Operations Center. The net customer-owned generating facility output, which is the customer-owned generating facility generation less the station service load and step-up losses, is normally telemetered.

Specification 1: A dedicated communications link is required for General Telemetry, but this link may be shared with the Revenue Metering System and Voice Communications. Table 3 summarizes telemetry requirements and the following includes specific requirements based on customer-owned generating facility size:

- a) Telemetry is required when the output of the customer-owned generating facility entering the District Electric System is 3.0 MVA or greater: For this case, the telemetry of real power and energy (kW and kWh), and reactive power (kVAr and kVArh) is normally required.
- b) For customer-owned generating facilities below 3.0 MVA, the District determines telemetry needs on a case-by-case basis. Note that should an existing plant expand to over 3.0 MVA, telemetry is required for the entire plant output.

Specification 2: A voice communications link shall be required for coordination of system protection, control, and communications maintenance activities between the District and the customer-owned generating facility.

Table 3: General Metering and Telemetry Requirements

District Data Requirements¹			
System or Quantity	Energy Control Center	High Voltage Scheduling	Revenue Billing
kW	Yes	No	No ²
kWh	Yes	Yes	Yes
kVAr	Yes	No	No
kVArh	Yes	No	Yes
kV	Yes	No	No
Number of Units	Number on Line Number Available	Number on Line Number Available	No
Resource Size	≥ 3.0 MVA ¹	≥ 1 MVA	≥ 1 kW
Data Sample Rate	1 Second or other approved rate compatible with NERC Policy	Last Hour kWh sent each hour	Hourly kWh Data Retrieved daily
Generation Reserves	Contingency non- spinning MW Contingency Spinning MW Regulating MW	Contingency non- spinning MW Contingency Spinning MW Regulating MW	No

Notes:

1. Requirements for customer-owned generating facilities below 3.0 MVA are determined on an individual basis.
2. A kW reading for revenue billing may be required where special transmission arrangements are necessary.

5.4 Commissioning Requirements

This section contains the specifications that customers must meet when commissioning their facilities.

5.4.1 Start-Up (Initial Energization Inspection)

Specification 1: For equipment that can impact the District electric system, the customer shall develop an “Inspection and Test Plan” for pre-energization and energization testing.

Specification 2: The applicant is responsible for pre-energization testing of their generation, line, and load facility equipment.

Specification 3: Prior to initial energization of the customer-owned generating facility, inspection and/or tests shall be jointly performed by both the customer and designated District personnel to verify the proper operation of the generator(s) and associated equipment to the District’s satisfaction.

Specification 4: Commissioning testing will be required to demonstrate voltage step response, and voltage and frequency control systems.

5.5 Operations and Metering Requirements

This section contains the specifications required of interconnecting facilities in regard to operations and metering.

5.5.1 Revenue and Interchange Metering

Revenue metering includes energy (kWh) and reactive energy (kVARh) recorded by revenue meters on a demand interval basis. Interchange metering includes bi-directional energy and reactive data as well as special telemetering requirements for scheduling purposes. Energy data recording is required for District's billing and scheduling functions. The District typically owns and maintains the revenue metering at the load-metering and generation metering sites.

Specification 1: All interconnections of facilities capable of exchanging at least 1 kVA of active power require District qualified metering for revenue or interchange.

Specification 2: The metering shall be located to measure the net power at the point of interface to or from the District power grid.

Specification 3: Revenue and interchange metering, telemetering, and data communication facilities require calibration and testing on a programmed periodic basis to ensure correct data readings.

5.5.2 Generation Metering System

Generation metering usually consists of bi-directional meters and related communications systems providing active power (in kW) and energy (in kWh) from the point of interface with the District. Active power is telemetered on a continuous basis and is sent each hour to the District control center for District accounting. Effective telemetering requires real-time knowledge of the quality of measurement. Associated with the telemetering signal, various indications of telecommunications quality or failure shall be included.

Generation metering, telemetering, and data communication facilities require calibration and testing on a programmed periodic basis to ensure correct data readings.

5.5.3 Synchronizing of Facilities

Specification 1: The customer-owned generating facility shall be automatically synchronized with the District system and the customer shall be responsible for the automatic synchronization.

Specification 2: Synchronization capability shall be provided both at the utility tie breaker(s) and at the generator breaker(s).

Specification 3: Breakers used for synchronization may not have more than 5-cycle closing time.

Specification 4: All automatic synchronization shall be supervised by a synchronizing check relay.

Specification 5: The output of a synchronizing check relay used to supervise synchronization must be rated to interrupt the circuit breaker closing circuit current, and the interrupting device must be capable of trip-free operation.

5.5.4 Primary Metering

Specification 1: The District shall own, furnish, and install the standard bi-directional production metering to measure the energy delivered by the District to the customer and the energy received by the District from the customer.

Specification 2: A communications link is required for this Revenue Metering System.

5.6 Maintenance Requirements

Specification 1: The customer shall maintain their generating facility in good working order.

Specification 2: The customer-owned generating facility (generator and associated equipment) may be subject to District inspection upon reasonable notice by the District.

Specification 3: The customer shall assume full responsibility for the routine maintenance of the generating facility and associated protective devices and the keeping of records for such maintenance. These records shall always be available to the District for inspection.

Specification 4: The customer is responsible for generator performance testing, monitoring, and validation. The customer may also be required to perform additional tests as necessary to ensure compliance with WECC standards.

5.6.1 Maintenance Coordination

Specification 1: Transmission and distribution elements (e.g. lines, line rights of way, power transformers, circuit breakers, control and protection equipment, metering, and telecommunications) that are part of the proposed connection and could affect the reliability of the District electric system must be inspected and maintained in conformance with NERC, WECC, and District standards and guidelines, whichever is the most stringent.

Specification 2: The customer has full responsibility for the inspection, testing, calibration, and maintenance of their equipment, up to the location of change of ownership or point of service.

Note: Plant maintenance requirements are specified by NERC.

6 Documentation Requirements & Revision History

The District shall maintain and update the Interconnection Guidelines reflected in this document as necessary to maintain compliance with current NERC, WECC and District standards and guidelines.

Copies of this document will be provided within 5 business days upon request by sending your written request to:

Manager, System Planning and Protection

Public Utility District No. 1 of Snohomish County

P.O. Box 1107

Everett, WA 98206-1107

Revision History

Note to Revisers: Please review to see if update should also be made in the Distribution Interconnection Requirements.

Number	Date	Description	By	Reviewed by	Approved by:
Original	Sept. 29, 2011	Document Origination – Compilation of: 1) SNPD Electric Service Requirements 2) SNPD Customer Service Regulations 3) SNPD General Planning Guidelines, 2/4/10 4) SNPD Electric Transmission Protection Engineering Guidelines, 12/19/08 5) SNPD Electric Distribution Protection Engineering Guidelines, 12/19/08	D. Small	Mark Oens, Manager, System Planning and Protection Derek Backholm, Principal Engineer, System Protection Long Duong, Principal Engineer, Transmission Operations John Liang, Principal Engineer, Transmission Planning Anna Miles, Sr. Manager, Power Supply	
Revision 1	Dec. 18, 2013	Renumbered sections according to the NERC standard requirements numbering change. Minor edits throughout documents.	D. Small	System Planning Dept.	E. Tobin
Revision 2	Feb. 9, 2018	Revisions to Sections 2.0, 2.5 & 2.13 plus minor edits throughout	D. Small	System Planning and Protection	J. Zyskowski
Revision 3	June 18, 2026	Renamed from “Facility Connection Requirements”, re-structure document, divided into two documents [Transmission & Distribution], add in information about DER requirements	E. Parry	System Planning and Protection, Operations	A. Carstens

7 Appendix A: Form 6-1

SNOHOMISH COUNTY PUBLIC UTILITY DISTRICT NO. 1
Preliminary Application for Operation of Customer-Owned Generation

FORM 6-1

Who should file this application: Any customer(s) expressing interest to install generation on their premises. This application should be completed as soon as possible and returned to a District representative in order to begin processing the request.

Information: This application is used by the District to perform a Preliminary Interconnection Study to determine the interface requirements at the customer's service point. The applicant should attempt to fill in as much of the form as possible. The applicant will receive a preliminary estimate for the utility interface requirements that may be used in calculating the overall project requirements.

Further Action: The Preliminary Interconnection Study will determine the need to submit a copy of the Final Application for Parallel Operation of Customer-Owned Generation.

Equipment Testing: Prior to final approval of the customer's generation, protective and control system testing is required. District representatives and Owner representatives must be present to witness and verify the testing for proper operation.

Owner/Applicant Information

Company _____

Mailing Address _____

City _____ County _____ State _____ Zip _____

Phone _____ Representative _____

Project Design/Engineering (Architect) (as applicable)

Company _____

Mailing Address _____

City _____ County _____ State _____ Zip _____

Phone _____ Representative _____

Electrical Contractor (as applicable)

Company _____

Mailing Address _____

City _____ County _____ State _____ Zip _____

Phone _____ Representative _____

Generator Data

Manufacturer (if available) _____ Model _____

Type: Synchronous Induction Phases: Single Three Frequency (Hz) _____

Rated Output: _____ kW _____ kVA

Rated Power Factor: _____ (%) Rated Voltage (Volts): _____ Rated Amperes: _____

Energy Source (gas, steam, hydro, etc.) _____

Transfer Switch Data

Manufacturer _____ Model _____

Type _____ Rating _____ ANSI /UL 1008 Listed? YES NO

What Standards does it meet? _____

Is transfer switch operational in closed-transition mode? YES NO

What is maximum time the transfer switch takes to operate? _____

Can it be programmed to operate in parallel with District for more than 100 milliseconds (0.100 sec)?

YES NO

Estimated Load Information

The following information will be used to help properly design the District/customer interconnection. This information is not intended as a commitment or contract for billing purposes.

Minimum anticipated load (generation not operating) _____ kW _____ kVA

Maximum anticipated load (generation not operating) _____ kW _____ kVA

Description of Proposed Installation and Operation

Please attach a single line diagram showing the customer's primary switchgear, transformers, and generation facilities. Give a general description of the manner of operation of the generation (cogeneration, peak shaving, emergency power, etc.) Please attach additional sheets if necessary.

Signature

Applicant Signature _____ Date _____

Information below to be completed by Snohomish County Public Utility District

PUD Customer Service Representative completes the following:

Executive Account Rep _____ Phone _____

Project Name _____

Street Address _____

City _____ County _____ Phone _____

District service point location _____
(Attach map if available)

Copy of Application and attachment to:

_____ System Planning & Protection Manager

*** Original of this document to be retained in customer's file in Customer Service Department ***

8 Appendix B: Form 6-2

SNOHOMISH COUNTY PUBLIC UTILITY DISTRICT NO. 1
Final Application for Operation of Customer-Owned Generation

FORM 6-2

Who should file this application: *Customers defined by the Preliminary Interconnection Study performed by the District as having generation capable of operating in parallel with the District system. This application should be completed as soon as possible and returned to a District Representative in order to begin processing the request.*

Information: *This application is used by the District to perform a Final Interconnection Study to determine the required equipment configuration for the District/customer interface. Every effort should be made to supply as much information as possible.*

Additional Requirements: *In addition to the items listed on this form, please attach a detailed one-line diagram of the proposed facility, all applicable elementary diagrams of major equipment (generators, transformers, inverters, circuit breakers, protective relays, etc.), specifications, test reports, etc., and any other applicable drawings or documents necessary for the proper design of the interconnection.*

Equipment Testing: *Prior to final approval of the customer's generation, protective and control system testing is required. District representatives and Owner representatives must be present to witness and verify the testing for proper operation.*

Owner/Applicant Information

Company _____
Mailing Address _____
City _____ County _____ State _____ Zip _____
Phone _____ Representative _____

Project Design/Engineering (Architect) (as applicable)

Company _____
Mailing Address _____
City _____ County _____ State _____ Zip _____
Phone _____ Representative _____

Electrical Contractor (as applicable)

Company _____
Mailing Address _____
City _____ County _____ State _____ Zip _____
Phone _____ Representative _____

Estimated Load Information

The following information will be used to help properly design the District/customer interconnection. This information is not intended as a commitment or contract for billing purposes.

Minimum anticipated load (generation not operating) _____ kW _____ kVA

Maximum anticipated load (generation not operating) _____ kW _____ kVA

**Please complete all applicable items.
Copy this page as required for additional generators.**

Synchronous Generator Data

Unit No.(s) _____ Total number of units with listed specifications on site _____
 Manufacturer _____ Mfg. Date _____
 Serial No. (each) _____
 Phases: Single _____ Three _____ RPM _____ Frequency (Hz) _____
 Rated Output (for one unit) _____ kW _____ kVA
 Rated Power Factor _____ % Rated Voltage (Volts) _____ Rated Amperes _____
 Field Volts _____ Field Amps _____ Motoring Power (kW) _____
 Synchronous Reactance (Xd) _____ % on _____ kVA base
 Transient Reactance (X'd) _____ % on _____ kVA base
 Subtransient Reactance (X''d) _____ % on _____ kVA base
 Negative Sequence Reactance (Xs) _____ % on _____ kVA base
 Zero Sequence Reactance (Xo) _____ % on _____ kVA base
 Neutral Grounding Resistor (if applicable) _____

 I²t or K (heating time constant) _____
 Additional information _____

Induction Generator Data

Rotor Resistance (Rr) _____ ohms Stator Resistance (Rs) _____ ohms
 Rotor Reactance (Xr) _____ ohms Stator Reactance (Xs) _____ ohms
 Magnetizing Resistance (Xm) _____ ohms Short Circuit Resistance (Xd'') _____ ohms
 Design Letter _____ Frame Size _____
 Exciting Current _____ Temp Rise (° C) _____
 Reactive Power Required _____ Vars (no load) _____ Vars (full load) _____
 Additional information _____

Prime Mover (please complete all applicable items)

Unit No. _____ Type _____
 Manufacturer _____ Serial No. _____
 Mfg. Date _____ HP Rated _____ HP Max _____ Inertia Constant _____ lb-ft²
 Energy Source (hydro, steam, wind, etc.) _____

Generator Transformer (please complete all applicable items)

Transformer (between generator and utility system)
Generator Unit No. _____
Manufacturer _____ Mfg. Date _____
Serial No. _____
High Voltage _____ kV, Connection: _____ delta _____ wye, Neutral solidly grounded? _____
Low Voltage _____ kV, Connection: _____ delta _____ wye, Neutral solidly grounded? _____
Transformer Impedance (Z) _____ % on _____ kVA base
Transformer Resistance (R) _____ % on _____ kVA base
Transformer Reactance (X) _____ % on _____ kVA base
Neutral Grounding Resistor (if applicable) _____

Inverter Data (if applicable)

Manufacturer _____ Model _____
Rated Power Factor _____ % Rated Voltage (Volts) _____ Rated Amperes _____
Inverter Type (ferroresonant, step, pulse-width modulation, etc.) _____
Type Commutation: Forced _____ Line _____
Harmonic Distortion: Maximum Single Harmonic % _____
Maximum Total Harmonic % _____

NOTE: Please attach all available calculations, test reports, and oscillographic prints showing inverter output voltage and current waveforms.

Power Circuit Breaker (if applicable)

Manufacturer _____ Model _____
Rated Voltage (kV) _____ Rated Amperes _____
Interrupting Rating (Amperes) _____ BIL Rating _____ kV
Interrupting medium/Insulating medium (ex: vacuum, gas, oil) _____ / _____
Control Voltage (closing): _____ Volts _____ AC _____ DC
Control Voltage (tripping): _____ Volts _____ AC _____ DC _____ Battery _____ Charged Capacitor
Close Energy: _____ Spring _____ Motor _____ Hydraulic _____ Pneumatic _____ Other
Trip Energy: _____ Spring _____ Motor _____ Hydraulic _____ Pneumatic _____ Other
Bushing Current Transformers _____ Max. Ratio _____ Relay Accuracy Class _____
Multi ratio: _____ Yes _____ No (Available taps) _____

Miscellaneous (Please use this area and any additional sheets for applicable notes and comments)

Signature

The customer agrees to provide Snohomish County Public Utility District with additional information required to complete the interconnection. The customer shall operate his equipment within the guidelines set forth by the *Interconnection Requirements for Customer-Owned Generating Facility Connected to District Distribution/High Voltage System*.

Applicant Signature _____ Date _____

Information below to be completed by Snohomish County Public Utility District

PUD Customer Service Representative completes the following:

Executive Account Rep _____ Phone _____

Project Name _____

Street Address _____

City _____ County _____ Phone _____

District service point location _____
(Attach map if available)

Equipment Testing

Testing performed and witnessed for proper operation on ____/____/____ by:

Owner _____ Owner Rep _____ Contractor _____

Executive Account Rep _____ System Protection Rep _____

Project Designer / Engineer _____ Construction Rep _____

Miscellaneous Comments / Notes

Copy of Application and Attachments to:

- ____ Power & Business Services AGM
- ____ Transmission & Distribution Engineering Services Manager
- ____ System Planning & Protection Manager
- ____ Distribution Construction Services Manager

*** Original of this document to be retained in customer's file in Customer Service Department ***

9 Appendix C: New Service Questionnaire (NSQ)

COMMERCIAL

New Service/Rewire Questionnaire/Agreement

PROJECT INFORMATION - To be completed by contractor or property owner responsible for construction costs

Name - Legal name for contracts _____ Project Name _____ UBI/FEIN _____

Type of Business: Sole Proprietor LLC Partnership Corporation Phone Numbers: _____

Billing Address for Construction Charges _____ City _____ State _____ Zip _____

Service Address for Project _____ City _____ State _____ Zip _____

Parcel No.: _____ Approximate Project start date: _____

CONSTRUCTION CONTACTS - Name Phone Number Fax Email

Business Contact			
Electrical Contractor			
Site Super			

TEMPORARY SERVICE - for construction purposes only

Overhead Underground No temporary required Approx. date temporary needed: _____

Contact information for party responsible for Temporary fees and monthly consumption billing Same as above

Name: _____ Email: _____ Phone #: _____

NEW PERMANENT SERVICE OR CHANGES TO EXISTING SERVICE

New Construction Rewire - upgrading/changing existing service - Existing AMPs _____ Multi-Meter Number of Units: _____

Specify type of Business _____ Approximate date of permanent service: _____

Contact information for party responsible for permanent monthly consumption billing Same as above

Name: _____ Email: _____ Phone #: _____

ELECTRICAL SERVICE ENTRANCE - REQUIRED

Overhead Underground 200amps 400amps _____ amps _____ voltage Single-Phase Three-Phase

Phase Wire Size: _____ Neutral Wire Size: _____ Number of runs: _____ AL CU

ELECTRICAL LOAD INFORMATION - REQUIRED Existing New Voltage Phase

Building square footage: _____									
Lighting									
Heating <input type="checkbox"/> Electric <input type="checkbox"/> Gas <input type="checkbox"/> Other _____									
Cooling <input type="checkbox"/> Electric <input type="checkbox"/> Gas <input type="checkbox"/> Other _____									
Water Heating <input type="checkbox"/> Electric <input type="checkbox"/> Gas									
Electric Vehicle Charging <input type="checkbox"/> Level 1 <input type="checkbox"/> Level 2 <input type="checkbox"/> Level 3									
Miscellaneous									
Motor Loads									
Total:									

Motor Loads* (characteristics of proposed load):

Size in HP	Quantity	Soft Start?	Starting AMPs	Running AMPs	Phase	Class	Voltage	No. of starts	Per Day or HR

Will there be any generation at this facility? Yes No If yes, what kind of interconnection? Open transition Closed transition

In order to proceed with the engineering and determination of charges, the following information may be required:

- Electronic site plan required with lot lines, dimensions, easements, ROW, sewer, storm & desired transformer location. Attached? Yes No
- Complete riser diagram / one-line with desired metering location (one location per building) Attached? Yes No
- Grades & Stakes form signed attesting that property corner locations and final grade is established. Attached? Yes No
- Will existing power facilities require relocation? Yes No

Prior to energizing the service, all PUD standards and service requirements must be met and approved by the PUD. You can find the Electrical Service Requirements at: www.snopud.com/construction. Email application and documents to: inspections@snopud.com.

It is understood that if additional work is required of the PUD, due to customer revisions of the electrical load and/or voltage requirements or other information as supplied or requested on this form, the additional costs shall be borne by the customer. **The PUD provides for installed load, not future load.**

Customer Signature _____ Date: _____

Electronic Signature: By checking the Signature box, inserting my name on the signature line, and submitting the form electronically to the PUD, I certify that I understand and agree to the above terms.

****To establish your permanent service usage billing account, please contact our Customer Service Department at 425-783-8442. We will not be able to install and energize the permanent meter without an account set-up.

PUD INTERNAL USE Date Received: _____	Billing Partner: _____	Sold to: _____	Assigned Engineer: _____
<input type="checkbox"/> Scanned to BSR@snopud.com	Connection Object: _____	Ship to: _____	Fees Paid _____












Interconnection Requirements_Transmission

Final Audit Report

2026-06-18

Created:	2026-06-18
By:	Cherilyn Suiter (CJSuiter@snopud.com)
Status:	Signed
Transaction ID:	CBJCHBCAABAyIBRm7X1XKcCsFHJJTma14yrr9Ltabkw

"Interconnection Requirements_Transmission" History

-  Document created by Cherilyn Suiter (CJSuiter@snopud.com)
2026-06-18 - 5:27:11 PM GMT
-  Document emailed to Emily Parry (eeparry@snopud.com) for signature
2026-06-18 - 5:28:54 PM GMT
-  Document emailed to Jeanne Harshbarger (jwharshbarger@snopud.com) for signature
2026-06-18 - 5:28:54 PM GMT
-  Document emailed to Amy Cartstens (acarstens@snopud.com) for signature
2026-06-18 - 5:28:54 PM GMT
-  Email viewed by Emily Parry (eeparry@snopud.com)
2026-06-18 - 5:29:22 PM GMT
-  Document e-signed by Emily Parry (eeparry@snopud.com)
Signature Date: 2026-06-18 - 5:29:49 PM GMT - Time Source: server - Signature Appearance Selected: TYPE
-  Email viewed by Jeanne Harshbarger (jwharshbarger@snopud.com)
2026-06-18 - 6:07:25 PM GMT
-  Document e-signed by Jeanne Harshbarger (jwharshbarger@snopud.com)
Signature Date: 2026-06-18 - 6:08:43 PM GMT - Time Source: server - Signature Appearance Selected: IMAGE
-  Email viewed by Amy Cartstens (acarstens@snopud.com)
2026-06-18 - 11:33:03 PM GMT
-  Document e-signed by Amy Cartstens (acarstens@snopud.com)
Signature Date: 2026-06-18 - 11:33:58 PM GMT - Time Source: server - Signature Appearance Selected: TYPE
-  Agreement completed.
2026-06-18 - 11:33:58 PM GMT