Idaho Power Facility Interconnection Requirements for Transmission Systems

(46 kV and Higher Voltages)

This document and all attachments are subject to change, and serve as a template for interconnecting new generation, lines, or end-user facilities. Not all interconnections may require all of the items in this document, and engineering judgment will be made on a case-by-case basis. The current version of this document will be posted on the Idaho Power OASIS page.

This document addresses the requirements of NERC Reliability Standard FAC-001-4 for Idaho Power's Functional Entities of Transmission Owner (TO) and Generator Owner (GO).

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1. DEFINITIONS

Affected System: An electric system other than the Transmission Provider's transmission System that may be affected by the proposed interconnection.

Affected System Operator: The entity that operates an Affected System.

Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load Interchange-generation balance within a BAA, and supports interconnection frequency in real time.

Balancing Authority Area (BAA): The collection of generation, transmission, and loads within the metered boundaries of the BA. The BA maintains load resource balance within this area.

New Generation Facilities: Facilities that have not been and are not yet connected to the Idaho Power transmission system.

2. INTRODUCTION

This document addresses the technical requirements for generation facilities, transmission facilities, and end-user facilities that are interconnected with Idaho Power's transmission system. This document, along with Idaho Power's Open Access Transmission Tariff (OATT), ensures that adverse impacts on reliability of the transmission system are avoided.

This document addresses certain aspects of interconnection; its scope is primarily technical and does not include the commercial requirements for connecting generators or transmission facilities.

Technical studies will determine whether Idaho Power will be required to modify its transmission system to interconnect the requested facilities. Technical studies may be performed by Idaho Power, a third-party contracted by Idaho Power, or some combination of the two. Parties requesting interconnection are responsible for the expense of these technical studies.

3. INTERCONNECTION REQUEST

This document applies to generation, transmission, and end-user facilities that are physically connected to, or desire to physically connect to Idaho Power's transmission system. Applicability is further defined by the categories below:

3.1 Generation Facilities

All requirements described or referred to in this policy apply to new and active generation facilities. New generation facilities are facilities that have not been and are not yet connected to the Idaho Power transmission system. Additional technical requirements may apply to special business arrangements or electrical configurations of Idaho Power's transmission system or the interconnection point(s).

Requests for new generation interconnections or existing generation interconnections seeking to make a qualified change will be consistent with the process for interconnection outlined in the Idaho Power Open Access Transmission Tariff (OATT) or the applicable State-jurisdictional process[1] (PURPA process) for generators interconnecting to the transmission system. Where applicable for generation interconnection requests, the specific timeline, queuing, and submission requirements in the Tariff or applicable PURPA process will be followed. Requests for generation interconnection require significant information regarding the Project. Specifics of required information as well as more information about the generation interconnection process and necessary forms are available on Idaho Power's OASIS at:

Idaho Power OASIS

and Idaho Power's website at:

Generator Interconnection - Idaho Power

3.1.1 Qualified Changes for Generation Facilities

Description	Detailed Example(s)
Change in Generator Output	**Examples** • Change that affects its Seasonal Real Power or Reactive Power capability by more than 10% of the last reported verified capability and is expected to last more than six months. • Change in power factor capability of the generator

Change of GSU	**Examples**
	• Change of a Generator Step-Up (GSU) transformer that results in any of the following differences:
	  ○ Reduction in rating by more than 10%
	  ○ Impedance change by more than 10%
	    ▪ Change in transformer losses
	    ▪ Change in transformer saturation differences

Change in Generator Characteristics	**Examples** • Change in the inertia of the Generator by more than 10% • Change in steady state transient and sub-transient reactance of the Generator or generator Interconnection Facilities by more than 10% • Changes that alter the equipment response characteristic ○ Includes excitation control system, plant volt/var, active power/frequency control, or turbine/governor & load control functions

[1] Schedule 72 for Idaho PURPA projects and the Oregon Qualifying Facility Large Generator Interconnection Procedures (QF-LGIP) for large Oregon PURPA projects.

<table>
<tr><th>Description</th><th>Detailed Example(s)</th></tr>
<tr><td></td><td>• Changes to a generator's electromagnetic transient models.</td></tr>
<tr><td>Change in Protection System of the generator facilities or generator interconnection facilities</td><td>Examples
• Changes in relay settings that prevent an applicable generating unit with frequency or voltage protection from meeting the criteria in this document or the removal of settings that previously limited voltage and/or frequency operation from meeting the applicable criteria of this document.
  o includes high and low frequency settings along with delay times if applicable
  o includes high and low voltage settings along with delay times if applicable</td></tr>
<tr><td>Inverter Based Resource (IBR) Only: Change in Inverter or inverter settings</td><td>Examples
• Change of 10% or more of the inverter-based resource units at a facility that is not replacement in-kind.
• Change in any control settings:
  o resulting in a difference in frequency or voltage support of the Inverter Based Resource
  o resulting in a difference in when the IBR discontinues current injection to the GRID (i.e. blocking commands)</td></tr>
<tr><td>Unplanned change in governor or governor settings</td><td>Examples
Uncharacteristic changes that result in how the generator responds to grid frequency deviations and is expected to last more than six months.</td></tr>
<tr><td>Unplanned change in exciter or exciter settings</td><td>Examples
Uncharacteristic changes that result in how the generator responds to grid voltage deviations and is expected to last more than six months.</td></tr>
<tr><td>Change in power system stabilizer</td><td>Examples
• Addition or removal of power system stabilizer
• Setting changes of power system stabilizer</td></tr>
</table>

3.2 Transmission Facilities

Any transmission facility addition shall maintain or improve the level of system reliability that existed prior to the interconnection. Real and reactive power that flows as a result of the transmission interconnection shall not overload or adversely affect Idaho Power’s transmission system or the WECC regional transmission system.

Requests for new transmission or line interconnections or existing transmission interconnections seeking to make a qualified change are initiated by completion of the request form, which can be found on Idaho Power's OASIS. No application fee is required. A scoping meeting will be held to fully discuss the request and all aspects of the proposed line interconnection. Study agreements will follow and will require deposits.

3.2.1 Qualified Changes for Transmission Facilities

Description	Detailed Example(s)
Change in Rating	**Examples** • Change in the facility thermal rating by greater than 5% • Change in the facility impedance by greater than 5% • Change in facility voltage class
Change in Protection Coordination	**Examples** • Change in the protection coordination that would alter the way a facility would clear faults or reclose.
Change in Topology	**Examples** • Change in topology that would alter power flows on the BES

3.3 End-User Facilities

Any proposed load customer interconnecting into Idaho Power's high-voltage transmission system or existing end-user interconnection seeking to make a qualified change shall be coordinated and reviewed through Idaho Power's Large Load Request process.

Information regarding Idaho Power's electric service requirements for new load (end-user) connections, applicable tariffs, project initiation information requirements and contact numbers may be found on the Idaho Power web site (Idaho Power). Submittal of project information to an Idaho Power customer service representative will start the communication and evaluation process.

3.3.1 Qualified Changes for End-User Facilities

Description	Detailed Example(s)
Increase in Demand	**Examples** • Annual increase in Demand exceeding 10% • Increase in Demand of 75 MW or greater within the next two years • Increase in Demand of 20 MW or greater within the next two years for a third-party Facility interconnected to a Generator Owner's Facility
Addition of equipment that would significantly	**Examples**

Description	Detailed Example(s)
impact the composite load model used to represent a Facility	• Installation of a motor 1,000 hp or larger where no motors previously existed • Addition of a motor exceeding the size of all other motors connected within a Facility with at least 500 hp of motors
Changes in protection schemes or settings or changes in end-user facility topology	**Examples** • Change in protection, controls, or topology that would alter power flows on the BES
Changes in harmonic levels	**Changes in harmonic levels will be evaluated based on guidelines found in IEEE 519, "IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems"**

4. INTERCONNECTION STUDIES

4.1 Generation Facilities

Generation interconnection studies will be consistent with the process for generation interconnection outlined in the Idaho Power Tariff or applicable PURPA process.

4.2 Transmission Facilities

Interconnection of a transmission facility requires a System Impact Study (SIS), which includes powerflow analysis, short circuit studies, and dynamic studies under both normal and contingency conditions as necessary. In addition, electromagnetic transient (EMT) studies may be required. For example, a series capacitor compensated transmission line may have Subsynchronous Resonance (SSR) interactions with Generation Resources. Should the transmission interconnection customer decide to move forward, the SIS is followed by a Facility Study. SIS and Facility Studies require a deposit.

4.3 End-User Facilities

An Engineering Assessment (EA) will evaluate the network impact, provide details of the network impact and upgrades required for the requested load, provide a rough estimate for the upgrade costs, and provide a timeline for installation. In addition, Idaho Power will provide the load customer with the amount of load that can be added without any network upgrades; up to the requested megawatts (MWs). The timeframe for the Engineering Assessment will vary based on project complexity. Should the interconnection customer decide to move forward the EA is followed by Construction Study. Engineering Assessments and Construction Studies require a deposit.

5. GENERATION INTERCONNECTION MODEL REQUIREMENTS

5.1 Steady State Models

Power flow models of the generation facility for each type of generation in PowerWorld or GE PSLF format, including:

- Transmission lead line to POI with impedances, MVA ratings, and line length.
- Generation substation transformer with impedances, MVA ratings, and tap position.
- Equivalent collector system(s) with impedances and MVA ratings.
- Equivalent aggregation(s) of generator step-up transformers with impedances and MVA ratings.
- Equivalent aggregation(s) of generating units including MVA and reactive capacities.
- Local service load(s).
- Reactive devices (if any).
- Automatic control settings of reactive devices or load tap changing transformers.

5.2 Dynamic Models

Dynamic models of the generation facility for each type of generation in GE PSLF format, including:

- Grid Interface (regc_* model)
- Electrical Controller (reec_* model)
- Plant-Level Controller (repc_* model)
- Voltage Protection (lhvrt model)
- Frequency Protection (lhfrt model)
- Wind projects require additional models which may include, but are not limited to, Aerodynamic Model, Pref Controller, Stabilizer, and Governor.

5.3 Data Verification

Data sufficiency verifications on the submitted technical data include:

- Model values such as impedances, capacities, ratings, line lengths, reactive capability, BESS discharge time, etc., should match the data filled out in the project's application and single-line diagram (SLD).
- AC-coupled hybrid plants must use the repc_b model for their Plant-Level Controller.
- Any plants containing BESS (except for DC-coupled hybrid plants with DC-side charging only) must use the reec_c or reec_d model for their BESS Electrical Controller.

- DC-coupled hybrid plants with DC-side charging only must use the reec_a or reec_d model for their BESS Electrical Controller.
- Voltage Protection (lhvrt) and Frequency Protection (lhfrt) model settings should meet NERC PRC-024 and PRC-029 when effective (Inverter Based Resources only) standards and should monitor the POI voltage.
- Control mode should be Voltage Control.
- The preferred voltage regulated bus is the low-side of the substation transformer, but the high-side is allowed with appropriate droop controls.
- Frequency response should be enabled with a droop of at least 5%.
- Transient stability simulation results should include:
    - i. Flat response for a no disturbance run.
    - ii. Stable recovery to pre-disturbance output following the clearing of a solid three-phase fault.
    - iii. Fault ride-through response for voltage levels required by PRC-024 and PRC-029 when effective (Inverter Based Resources only).
    - iv. Step response that regulates voltage to 90% of setpoint within 30 seconds.

5.4 Electromagnetic Transient (EMT) Model Requirements

EMT models are required to support current and future study efforts which are required to maintain a reliable power system. Some of the most common studies that require the use of EMT models are:

- Interconnection to a weak system
- Sub-synchronous oscillation (SSO)
- Control Interaction Analysis

5.4.1 Interconnection to a Weak System

When a generator interconnecting to a transmission system is large relative to the rest of the system, it has a relatively large dynamic influence on the system, and the system may be termed weak. “Weak” is a relative term, and typically does not have hard quantitative metrics associated with it. It is not always initially clear when a system will become too weak to support generation. Conventional modeling tools may not be sufficiently detailed to represent the issues which will be encountered in actual equipment.

Power electronic equipment provided by different manufacturers may respond differently to similar network conditions. Additionally, influences from nearby devices may or may not have a significant impact on a particular generator interconnection.

5.4.2 Sub-Synchronous Oscillation (SSO) Analysis

SSO is a family of stability phenomena where the electrical resonance introduced by a capacitor causes the capacitor to exchange energy with either conventional generators, or non-conventional generators like wind. Series compensated transmission lines introduce the risk of SSO.

In the case of conventional generators, these interactions are termed sub-synchronous resonance (SSR). In the case of non-conventional generators, these interactions are termed sub synchronous control interactions (SSCI). SSCI is most probable when certain types of wind turbines are operated in very close proximity to series capacitors, particularly if there are no other parallel outlets for the wind energy ("radial" connections). If unchecked, SSCI can introduce oscillations onto the power system which can very quickly grow to damaging levels. In the worst cases, it can lead to electrical instability which can trigger power system protection, damage wind turbines, or damage series capacitor equipment.

Many modern wind turbines are susceptible to SSCI, and therefore a direct connection to a series compensated line, or a connection which may (through outages) become radial or near radial, requires careful study. An SSCI study is performed using highly detailed electromagnetic transient type computer models. These models shall represent the turbine controls in fine detail, and any possible network conditions requiring operation of the wind plant directly (or nearly directly) into a series capacitor shall be simulated to ensure the specific turbines chosen will be immune to SCCI phenomena. Conventional transient stability models are unable to represent the SSCI phenomena due to inherent limitations in the model type.

5.4.3 Control Interaction Analysis

Power electronic based devices such as wind turbines, HVDC transmission system, STATCOMs, and SVCs are highly controllable, and the controls may operate to perform specific functions within a wide range of timeframes and operating conditions. If two or more of these devices are in operation in close electrical proximity to each other but have been designed and commissioned in isolation from each other, there is a potential for the controllers to interfere with each other, and the overall system performance could be degraded.

Due to the level of detail required in the models to accurately represent the fast control loops used in these devices, EMT models are required.

5.4.4 Model Requirements

The model must:

A. Represent the full detailed inner control loops of the power electronics. The model cannot use the same approximations classically used in transient stability modeling, and must fully represent all fast inner controls, as implemented in the real equipment.

B. Represent all control features pertinent to the type of study being done. Examples include external voltage controllers, customized PLLs, ride-though controllers, SSCI damping controllers, and others. As in point A, actual hardware code is required to be used for most control and protection features. Operating modes that require system specific adjustment must be user accessible.

C. Represent plant level control. Power Plant Control (PPC) representation must be included which represents the specific controllers used in the plant. Plant controllers must be represented in sufficient detail to accurately represent short term performance, including specific measurement methods, communication time delays, transitions into and out of ride-through modes, settable control parameters or options, and any other specific implementation details which may impact plant behavior. Generic PPC representation are not acceptable unless the final PPC controls are designed to exactly match the generic PPC model. If multiple plants are controlled by a common controller, or if the plant includes multiple types of IBRs (e.g., Hybrid BESS/PV) this functionality must be included in the plant control model. If supplementary or multiple voltage control devices (e.g., STATCOM) are included in the plant, these should be coordinated with the PPC.

D. Represent all pertinent electrical and mechanical configurations. This includes any filters and specialized transformers. There may be other mechanical features such as gearboxes, pitch controllers, or others which must be modeled if they impact electrical performance within the timeframe and electrical purview of the study. Any control or dynamic features of the actual equipment which may influence behavior in the simulation period which are not represented, or which are approximated, must be clearly identified.

E. Have all pertinent protections modeled in detail for both balanced and unbalanced fault conditions. Typically, this includes various OV and UV protections (individual phase and RMS), frequency protections, DC bus voltage protections, converter overcurrent protections, and often other inverter specific protections. Any protections which can influence dynamic behavior or plant ride-through in the simulation period must be included. Actual hardware code is recommended to be used for these protection features.

F. Be configured to match expected site-specific equipment settings. Any user-tunable parameters or options must be set in the model to match the equipment at the specific site being evaluated, as far as they are known. Default parameters are not appropriate unless these will match the configuration in the installed equipment.

G. Have control or hardware options which are pertinent to the study accessible to the user. Although plant must be configured to match site specific settings as far as they are known, parameters pertinent to the study must be accessible for use by the model user. Examples of this could include protection thresholds, real power recovery ramp rates, frequency or voltage droop settings, voltage control response times, or SSCI damping controllers. Diagnostic flags (e.g. flags to show control mode changes or which protection has been activated) should be visible to aid in analysis.

H. Be accurate when running at a simulation time step of 10 µs or higher.

I. Operate at a range of simulation time steps. The model must not be restricted to operating at a single time step but must be able to operate withing a range (e.g., 10 µs – 20 µs).

J. Include documentation and a sample implementation test case. Test case models must be configured according to the site-specific real equipment configuration up to the Point of Interconnection. This would include (for example): aggregated generator model, aggregated generator transformer, equivalent collector branch, main plant transformers, gen-tie line, power plant controller, and any other static or dynamic reactive resources. Test case must use a single machine infinite bus representation of the system, configured with an appropriate representative SCR.

K. Have an identification mechanism for configuration. The model documentation must provide a clear way to identify the specific settings and equipment configuration which will be used in any study, such that during commissioning the settings used in the studies can be checked. This may be control revision codes, settings files, or a combination of these and other identification measures.

L. Accept external reference variables. This includes real and reactive power ordered values for Q control modes, or voltage reference values for voltage control modes. Model must accept these reference variables for initialization and be capable of changing these reference variables mid-simulation, i.e., Dynamic signal references.

M. Be capable of initializing itself. Once provided with initial condition variables, the model must initialize and ramp to the ordered output without external input from simulation engineers. Any slower control functions which are included (such as switched shunt controllers or power plant controllers) must also accept initial condition variables if required. Note that during the first few seconds of simulation (e.g., 0-2 seconds), the system voltage and corresponding terminal conditions may deviate from nominal values due to other system devices initializing, and the model must be able to tolerate these deviations or provide a variable initialization time.

N. Have the ability to scale plant capacity. The active power capacity of the model must be scalable in some way, either internally or through an external scaling component. This is distinct from a dispatchable power order and is used for modeling different capacities of plant or breaking a lumped equivalent plant into smaller composite models.

O. Have the ability to dispatch its output to values less than nameplate. This is distinct from scaling a plant from one unit to more than one and is used for testing plant behavior at various operating points.

P. Initialize quickly. Model must reach its ordered initial conditions as quickly as possible (for example < 5 seconds) to user supplied terminal conditions.

5.4.5 Model Test Checklist

All criteria outlined in Idaho Power's EMT Model Test Checklist document must be met. The EMT Model Test Checklist document can be found on the Idaho Power OASIS page here.

6. INTERCONNECTION FACILITY DOCUMENTATION

1. Single line diagram (SLD) of the generation facility.
2. Manufacturer documentation for equipment to be installed.

7. INTERCONNECTION COORDINATION

Once a new request is considered feasible for interconnection, and Idaho Power has determined it affects other interconnected electric system owners, Affected System(s) will be identified, and Idaho Power will facilitate notification. Idaho Power may also notify the NorthernGrid regional planning group and/or WECC, as applicable to the specific interconnection request.

8. INTERCONNECTION CUSTOMER REQUIREMENTS

8.1 Access to Facilities

With reasonable notice and supervision, the interconnection customer shall allow Idaho Power personnel ingress and egress to equipment for operation, maintenance, repairs, tests (or witness tests), inspection, replacements, or removal of facilities/equipment. Idaho Power personnel shall be provided with an escort if necessary (rather than taking a special training course to enter the facility). If this access is not allowed, and it affects Idaho Power's customers, including emergency incidents or other power delivery-related activities, Idaho Power reserves the right to exercise the disconnection provision of the facility interconnection agreement.

8.2 Responsibilities

Interconnected parties are responsible for designing, installing, operating, and maintaining interconnection equipment that they own (i.e., generators, transformers, switches, relays, breakers, etc.). All protective devices necessary to protect the interconnected facilities are the responsibility of the customer.

Idaho Power's requirements specified in this policy are designed to protect Idaho Power facilities and maintain grid reliability pursuant to applicable reliability criteria.

Interconnected customers must satisfy the requirements in:

A. This policy,

B. Applicable rules and tariffs of jurisdictional state regulatory agencies and the Federal Energy Regulatory Commission (FERC),

C. Idaho Power's project-specific requirements (interconnection agreement or Electric Service Agreement [ESA] / Generation Interconnection Agreement [GIA]), and

D. Applicable policies of the Western Electricity Coordinating Council (WECC), the North American Electric Reliability Corporation (NERC), or their successor organizations,

   i. Some specific NERC standards families that may apply are:

      - BAL Resource and Demand Balancing
      - CIP Critical Infrastructure Protection

- COM Communications
- EOP Emergency Preparedness and Operations
- FAC Facilities Design, Connections and Maintenance
- INT Interchange Scheduling and Coordination
- IRO Interconnection Reliability Operations and Coordination
- MOD Modeling, Data, and Analysis
- PER Personnel Performance, Training, and Qualifications
- PRC Protection and Control
- TOP Transmission Operations
- TPL Transmission Planning
- VAR Voltage and Reactive

Idaho Power's review and written acceptance of the interconnected entity's equipment specifications and plans shall not be construed as confirming or endorsing the interconnected entity's design, as warranting the equipment's safety and durability, or in any way relieving the interconnecting entity from its responsibility to meet the above requirements. Idaho Power shall not, by reason of such review or lack of review, be responsible for strength, details of design, adequacy, or capacity of equipment built to such specifications, nor shall Idaho Power's acceptance be deemed an endorsement of such equipment.

9. OWNERSHIP POLICY AND OPERATION OF INTERCONNECTION EQUIPMENT

Idaho Power, as the Transmission Provider (TP), shall own all TP interconnection facilities and system upgrades necessary to assure reliable service to Idaho Power customers. This may include, but is not limited to: relaying, control systems, breakers, switches, bus work, and transmission lines. In all cases revenue metering will be owned and maintained by Idaho Power.

10. REVISIONS AND UPDATES

Idaho Power may revise the technical requirements periodically to comply with new requirements and/or recommendations from FERC, NERC, state, other governmental authorities. Idaho Power may require that all generator, transmission line, and end-user interconnections comply with new regulations by implementing similar procedures and/or upgrades as would be expected on Idaho Power facilities in a non-discriminatory manner. If the interconnection customer does not comply, Idaho Power may require an upgrade of the interconnection customer's facilities as necessary to be compliant. Any such upgrades shall be executed at the customer's expense. Alternately, Idaho Power may disconnect the interconnection customer after notification.

11. TRANSMISSION CAPABILITY

Interconnections to Idaho Power’s electric system may require that one or more of Idaho Power’s transmission lines be looped through a Point of Interconnection (POI) switching station (with circuit breakers) or a tapped interconnection to be sectionalized with the addition of switching equipment. The design and ratings of these facilities shall not restrict the capability of the lines and Idaho Power’s contractual transmission path rights.

12. GENERAL PROVISIONS

Idaho Power, at its sole discretion, may elect to upgrade or change the voltage level of the Idaho Power electric system serving the interconnection customer.

The interconnection design shall be capable of accommodating Idaho Power electric system reclosing practices.

The interconnection design shall incorporate protection equipment to detect system abnormalities or disturbances in either the interconnection customer’s system or the Idaho Power system. This equipment shall have the capability to isolate the sources of the disturbance.

The interconnection customer’s design and facilities shall provide all necessary equipment to protect against over-tripping or unnecessary loss of generation or inadvertent rapid and repetitive tripping and reclosing of the interconnection on the Idaho Power system.

The customer shall not cause the Idaho Power electric system to violate WECC System Performance Criterion.

The customer shall control the electrical real (MW) and reactive (MVAr) power output such that it will not exceed the capacity of the interconnection facilities.

The interconnection customer's three-phase generation shall be connected to the Idaho Power system with three-phase automatic disconnecting devices (circuit breakers), which are intended to significantly reduce the possibility of damaging the interconnection customer's generation equipment due to single-phase operation. These disconnecting devices shall be equipped with auxiliary contacts that indicate the actual status of the devices' main contacts.

An isolating device, typically a switch, must be installed to physically and visibly isolate the interconnection customer and Idaho Power systems. The disconnect switch will serve as the point of change of ownership between the customer and Idaho Power. The disconnect shall be owned and operated by Idaho Power to provide a visible air gap with clearances for adequate grounding, maintenance, and repairs of the Idaho Power electric system. Idaho Power may require the capability to apply safety grounds on the Idaho Power side of the disconnect. The customer shall not remove any Idaho Power padlocks or safety tags as per the Occupational Safety and Health Administration (OSHA) lockout/tagout requirements. In any case the device:

- must simultaneously open all phases (gang operated) to the interconnected facilities,

- must be accessible by Idaho Power and must be under Idaho Power Dispatcher jurisdiction,
- must be lockable in the open position by Idaho Power,
- shall not be operated without advance notice to affected parties, unless an emergency condition requires that the device be opened to isolate the interconnected facilities, and
- must be suitable for safe operation under all foreseeable operating conditions.

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

- if it is necessary for the protection of maintenance personnel when working on de-energized circuits,
- if the interconnected facilities or Idaho Power equipment presents a hazardous condition, or
- if the interconnected facilities jeopardize the operation of Idaho Power's system.

Industry standard basic insulation level (BIL) ratings shall be used for electric system additions and electric system interface equipment. The electric equipment shall meet IEEE C62.41 or C37.90.1, V&I Withstand Requirements.

The harmonic content of the voltage and current wave forms of both the interconnection customer's and Idaho Power's systems shall comply with the latest version of the IEEE Standard 519, *Recommended Practices and Requirements for Harmonic Control in Electric Power Systems*.

The customer shall be capable of withstanding electromagnetic interference environments in accordance with ANSI/IEEE Standard C37.90.2. The interconnection system and protection system shall not mis-operate due to electromagnetic interference, including hand-held communication devices.

Idaho Power may install disturbance recording equipment or Phasor Measurement Units (PMU), at the customer's expense.

Telecommunication services required for, but not limited to, SCADA and Phasor Measurements are the sole responsibility of the customer to establish and maintain. Failure of these circuits may result in Idaho Power disconnecting the interconnection customer after notification.

The interconnection design shall incorporate adequate facilities to enable the on-site generation to be synchronized with Idaho Power's transmission system prior to interconnection. The interconnection customer's generator protection shall incorporate elements to block out-of-sync closing of the customer's facilities. The customer shall be solely responsible for synchronizing the generator to the system.

All points at which the generator can be paralleled with the Idaho Power electrical system must be clearly defined as synchronization points in the submittal documentation. A given installation may be designed such that there are several synchronization points.

13. TRANSMISSION INTERCONNECTION METERING REQUIREMENTS

13.1 General Information

This standard provides the metering requirements for interconnection to Idaho Power Company's (IPC) transmission system.

13.2 General Information

Revenue metering equipment shall be installed to accurately measure energy delivered and received at generation connections, load connections, and at the point of interconnect. Unless otherwise agreed upon, IPC will specify, procure, own, operate, and maintain the revenue metering packages at generating and transmission facilities, including IPC metering instrument transformers (PT's and CT's), mounting structures, conduits, meter sockets, meter socket enclosures, and transformer cabinets at the interconnecting customers' expense. Auxiliary meters used for operational metering data or as a check meter may be installed in tandem with the IPC meters as needed but must be designed and installed in a manner to not impede the function, accuracy, or maintenance of IPC revenue metering equipment.

IPC meters shall be installed to measure net generation or load and account for local service and any auxiliary loads created at a generation facility. All metering shall be installed on a structure as close to the instrument transformers as practical and within 0.5 miles from the point of interconnect. Unless the facility will be exclusively owned and operated by IPC, local service and/or auxiliary loads shall be independently metered. The interconnecting customer's protection equipment shall not share electrical equipment and instrument transformers associated with IPC revenue metering.

Final net metering shall take place at the point of interconnect, typically inside an IPC owned substation/facility. This final net meter shall sum all quantities of energy delivered and received from each generation and/or load connection and will be utilized for data and financial reporting.

Metering configuration, design, type, and layout will be determined by the type of generating equipment, the location of the facility on IPC's transmission system, and the required system operations (bi-directional vs. unidirectional power flow). For all metering configurations, IPC's grid will be considered the source. Energy flowing to the customer's load will be represented as channel 1 and energy flowing to the grid as generation will be represented as channel 2. A simplified metering layout schematic shall be provided to outline metering locations and energy flows. Typical interconnection metering layouts are provided in Exhibit A.

If metering standards cannot be met, an exception may be requested by providing information on what exception is being requested, why an exception is needed, and any alternate proposals to the IPC project representative.

13.3 Loss Compensation

All metered data must be compensated to the point of interconnect. Meters installed on the low side of the transformer must correct for losses from energy generation and energy consumption. Similarly, if the distance from any meter to the point of interconnect results in line losses of 0.1% or greater, loss compensation must be applied. IPC requires any applicable loss compensation be calculated and stored in IPC's MV-90 data (transformer losses) and Web Accounting (line losses) systems. A transformer test record and loss calculation report shall be submitted by the interconnecting customer indicating percentages of calculated additive or subtractive losses.

Any transmission interconnection metering that requires loss calculations shall be reviewed by IPC for approval.

13.4 Multiple Generation and Energy Storage

Sites with multiple generating technologies such as solar arrays, batteries, or wind collectors that are considered as **one unified transaction** are defined as a **Hybrid resource** and require metering for each generating technology and at a single point of interconnection.

Sites with multiple generating technologies that are considered as **separable transactions** are defined as a **Co-located resource** and require metering at each generation point. Co-located resources will require separate metering for each local service or auxiliary load connection.

When Energy Storage (batteries) are charged from the Idaho Power Transmission system and a generation solar/wind site, separate metering will be required — metering will be required at the Generation Facility/Energy Storage Facility and at the Point of Interconnect substation. Station auxiliary loads should be metered separately and exclusively for both a Storage Facility and Generation Facility. Local service or auxiliary loads must be metered in a manner to distinguish energy used for storage purposes or energy used for load within the station. To differentiate how energy from IPC's grid is utilized, local service must not be supplied from the grid site of any generation or storage device metering.

13.5 Revenue Metering Equipment

Metering equipment shall be of revenue grade, meeting all applicable industry standards (e.g., ANSI, IEEE, NEMA), and be compliant with the local regulatory authority (LRA) and CAISO standards (if applicable). Unless otherwise required by the system configuration and approved by IPC, IPC's most current standard high-end form 9S socket meter shall be used for all transmission interconnection projects.

13.6 Specifications

Generation and Transmission Interconnection Metering data shall be collected utilizing 4-quadrant metering and meters shall be capable of recording, storing, and transmitting bidirectional data recorded in 5-minute intervals. The metering package shall be capable of storing data for a minimum of 60 days. IPC will require real-time data for individual generators with ratings 3 MW and above or individual generators whose combined output exceed 3 MW at the same point of interconnection. The following quantities are required for all meters in accordance with CAISO standards: meter requirements.

(a) Kilowatt-hours—delivered
(b) Kilowatt-hours—received
(c) Kilovar-hours—delivered, received, for each quadrant
(d) Kilovoltamp-hours—delivered, received, for each quadrant
(e) Ampere-squared-hours
(f) Volts-squared-hours
(g) Kilowatts—delivered
(h) Kilowatts—received
(I) Kilovars—delivered, received, for any quadrant
(J) Kilovoltamps—delivered, received, for any quadrant

End-User Facility Metering is used for energy delivery to a customer's load, typically these meters do not require real-time data and are used primarily for accounting purposes. The meter will supply load profile and register data stored using IPC's data system.

13.7 Instrument Transformers

All instrument transformers shall be of revenue grade in accordance with applicable industry standards and fall within the CAISO instrument transformer requirements. CTs shall have a minimum accuracy of +/- 0.3% for Burdens B0.1 through B1.8 and have a continuous current thermal rating factor sized appropriately for the application.

13.8 Communications

Metering requires an ethernet, cellular, or other data quality communication for use with the IPC MV-90 remote meter data collection system and to remotely interrogate the meter. The interconnecting customer shall supply the communications facilities to an IPC provided demarcation point unless the Point of Interconnect is located inside an IPC station where existing IPC communication circuits are in place and available for utilization. Communications used to support metering data transfer shall be provided at the metering and utilize an ethernet network connection. Exceptions may be allowed if ethernet connections are proven not practical, in which case, an RS232 serial connection shall be utilized as an alternate.

13.9 Meter Compliance Testing

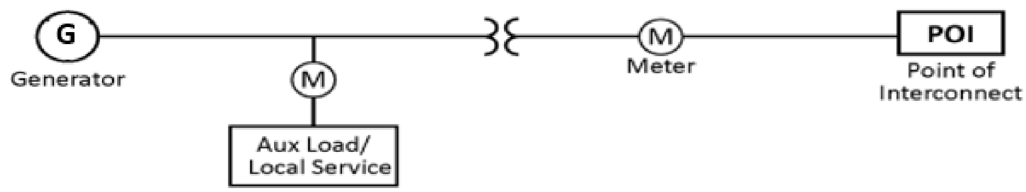
If the interconnecting site is a part of an Energy Imbalance Market (EIM), IPC shall inspect, test, recalibrate, and certify all metering equipment upon installation and at least biennially thereafter to verify and maintain accuracy according to CAISO and/or IPC requirements.

Non-EIM facilities testing will occur biennially for facilities over 10 MW, every four years for facilities between 10 MW and 1 MW, and as part of IPC's random sampling process for facilities below 1 MW.

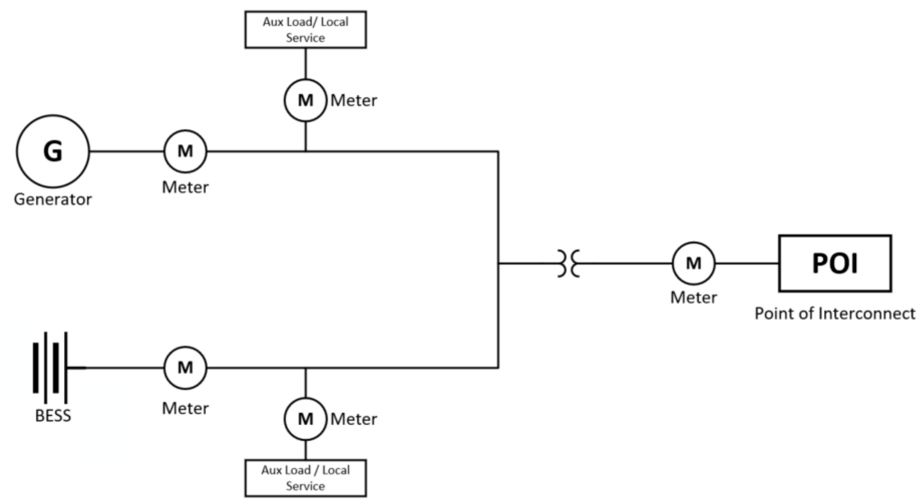
Upon request, IPC will give copies of the test results and advance notice of testing schedules. Requests for additional unscheduled testing will be honored at the expense of the requester unless the meters are found to be out of tolerance.

13.10 Exhibit A – Typical Generation Metering Layouts

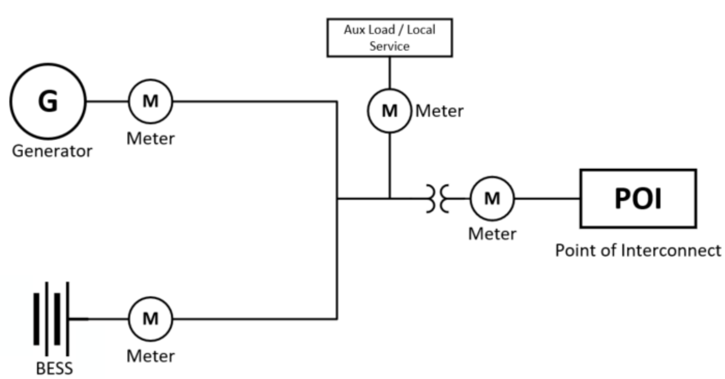
Single Generator



Multiple Generation Co-Located Resource



Multiple Generation Hybrid Resource



Note: Figures are intended for general use and guidance. Adjustments may be permitted.

14. TELECOMMUNICATION REQUIREMENTS FOR FACILITY INTERCONNECTION

14.1 Application

Before a new facility is interconnected to the Idaho Power system, Idaho Power will specify the associated telecommunications-related equipment required. This involves multiple critical systems on the power grid including metering and telemetering, protective relaying and interrupting devices, supervisory control and data acquisition (SCADA), and other data channels to support integration of the new facility. Due to the safety and reliability considerations involved, Idaho Power requires that all such telecommunications-related equipment be owned, installed, and maintained by Idaho Power at the generation facility's expense. For the protective relaying component, this requirement is limited to equipment installed to protect Idaho Power's system, or to the tie line into Idaho Power's system (if pilot line relay systems are required). The protective relays intended for protection of the interconnected generation facility are owned, installed, and maintained by the interconnection customer. When telecommunication channels are required as part of a protection and/or metering scheme, the general requirements below are to be followed.

Typical SCADA points required include but are not limited to:

From the point of interconnection substation:

<u>Analogs</u>:

- Net generation MW
- Net generator MVAR

<u>Accumulator Pulses</u>:

- Interchange metering kWh

From the interconnection customer's substation:

<u>Feedback and Control</u>:

- Generation Output Limit Control (GOLC)
- Frequency Response
- Voltage Control

<u>Status</u>:

- Main breaker 52A status
- Capacitor breaker 52A status

<u>Analog Written to the RTU</u>:

- Max Gen Limit MW Set Point

<u>Analogs</u>:

- Max Gen Limit MW Set Point Feedback

Additional SCADA points required for solar generation projects:

<u>Analogs</u>:

- Ambient Temperature (°C)

- Wind Direction (Degrees from North 0°-360°)
- Wind Speed (M/sec)
- Relative Humidity (%)
- Global Horizontal Irradiance (W/m^2)
- Plane of Array (W/m^2)

Additional SCADA points required for wind generation projects:

Analogs:

- Ambient Temperature (°C)
- Wind Direction (Degrees from North 0°-360°)
- Wind Speed (M/sec)
- Relative Humidity (%)
- Turbines in High-Speed Cutout (#)

14.2 General Requirements

The interconnection customer will be responsible for acquiring the communication lines from the local telephone company or multiple telephone companies as required to meet the telecommunications required of the new generation facility for the alternate metering data circuit. Due to the critical nature of the protection, metering, and SCADA, Idaho Power will own the communication facilities providing these circuits. The only exception to this is if no communication is required for protective relaying, in which case the SCADA may be on a leased communication circuit.

14.3 Telecommunication Circuit Requirements

14.3.1 New Generation Facilities < 3 MW with No Teleprotection Requirement

Metering requires a cell phone or other data communication connection for use with the Idaho Power MV-90 remote meter data collection system. An Ethernet connection is encouraged, but not required.

14.3.2 New Generation Facilities ≥ 3 MW or New Generation Facilities < 3 MW with Teleprotection Requirement

An Ethernet connection for use with the Idaho Power MV-90 remote meter data collection system is required. If an Ethernet connection is not possible, a land line or other data communication connection is required to remotely interrogate the meter.

14.3.2.1 Dispatch Business Telephone Line

A business telephone line is required so operating instructions from Idaho Power can be given to the designated operator of the generation facility equipment. Unless other arrangements are made to use Idaho Power’s existing telecommunications network, the interconnection customer must provide a local telephone service.

14.3.2.2 Protective Relay Remote Access Business Telephone Line

A business telephone line is required at the location of the protective relay equipment for remote access to the protective relay equipment. Unless other arrangements are made to use Idaho Power's existing telecommunications network, the interconnection customer must provide a local telephone line. Relevant CIP standards apply.

14.3.2.3 Protective Relays

Idaho Power will determine if non-pilot protective relays will be adequate for emergency tripping of the generation facility and/or protection of the distribution or transmission system or if tele-protected-type protection equipment is required. Idaho Power will design and provide telecommunications channels suitable for the protective relay package required at the expense of the generation facility. Local telephone company leased lines are not acceptable for protective relay channels. Telecommunication channels for protective relay equipment may consist of fiber optic system, power line carrier, microwave radio, or a combination of these systems.

14.3.2.4 SCADA Remote Terminal Unit (RTU)

Real-time data and/or control via a SCADA RTU is to be communicated to Idaho Power's Control Center(s). Unless other arrangements are made to use Idaho Power's existing telecommunications network, the interconnection customer must provide either a local telephone company VG36, Class B, Type-3, 4-wire, full-duplex communication line or an MPLS T1 from the generation facility to Idaho Power's location where the communication line terminates. Idaho Power will specify the location where the communication line will terminate. Telecommunication channels for SCADA RTU equipment, when using Idaho Power's telecommunications network, may consist of fiber optic system, microwave radio, other radio system, or a combination of these systems.

14.3.2.5 Alternate Telemetry

An alternate-meter telemetering of the total generation facility's kW output is to be communicated on a separate channel, but in a manner similar to the SCADA channel, to meet requirements for NERC Standard EOP-008-0, *Plans for Loss of Control Center(s) Functionality*. Unless other arrangements are made to use Idaho Power's existing telecommunications network, the interconnection customer must provide either a local telephone company VG36, Class-B, Type-3, 4-wire, communication line or an MPLS T1 from the generation facility to Idaho Power's Control Center(s). Idaho Power will specify the location of Idaho Power's closest communications facilities where the communication line will terminate. Telecommunications channel for the alternate-meter telemetering equipment, when using Idaho Power's telecommunications network, may consist of fiber optic cable, microwave radio, or a combination of these systems. The alternate-meter telemetering channel may use the same telecommunications system as the SCADA RTU channel providing it is not routed through Idaho Power's Control Center(s).

14.4 Telephone Company Line Treatment Equipment

Proper cable and protection equipment may be required at substations and other high-voltage electric facilities for expected ground potential rise (GPR). The GPR testing required to determine the required telephone line protection may be performed by Idaho Power at the expense of the generation facility or may be performed by the generation facility itself. The calculated GPR value will determine what grade of telephone cable high-voltage protection equipment is required, as well as the distance from the facility at which the telephone company pedestal will be located. The local telephone company must be informed in advance (up to six months) so outside plant facilities can be engineered to serve the generation facility location. Some independent telephone companies are not tariffed to provide protection equipment. In this case, the generating facility will be required to purchase and install the necessary telephone line protection equipment.

14.5 Communication Operating Conditions

14.5.1 Normal Operating Conditions

The customer shall provide to Idaho Power the information necessary to communicate with the equipment and/or personnel at the generation facility during routine operating conditions. This information shall be updated as soon as a material change becomes available for use by notifying Idaho Power's grid operations department.

14.5.2 Emergency Operating Conditions

The interconnection customer shall provide to Idaho Power the information necessary to communicate with the equipment and/or personnel at the generation facility during the loss of the primary communication medium. This would be considered the emergency operating condition. This information is also to be updated as soon as a material change becomes available for use by notifying Idaho Power's grid operations department.

15. PROTECTION AND CONTROL POLICY

15.1 AC Signals

AC current transformer signals necessary for protection, such as but not limited to, current differential protection, shall be made available by the interconnection facility seeking to connect to the Idaho Power system.

Generation facilities connecting to Idaho Power's transmission system are required to provide a return path for ground current at the interconnection point. This is achieved through the proper configuration of the facility owner's transformer that connects the generation interconnection system to the Idaho Power transmission system. For example, a wye-grounded / wye-grounded transformer with a delta tertiary or an autobank with a delta tertiary has the proper winding configuration to allow for ground current to return to Idaho Power's system through the transformer connections. By way of comparison, a delta / delta transformer does not allow for ground return current and a wye-grounded / wye-grounded transformer is a pass through only, thus neither are permitted for transmission connections.

15.2 Communications

Depending on the location of the interconnection, communication upgrades and/or integration may be required. Typical communication infrastructure for protective relaying at Idaho Power include, but are not limited to:

- Power Line Carrier
- Digital Microwave
- Fiber Optics

Signals between Idaho Power facilities and an interconnection facility may be required. These signals will be carried over a fiber optic medium and, as an example, are used for tripping isolation devices in the interconnection facility and/or Idaho Power facilities.

15.3 Line Protection

Many factors are considered when determining the protective relaying requirements needed by the interconnection customer to protect Idaho Power facilities and customers' equipment. Some of these factors are: the zone of protection, location of connection to Idaho Power system, location of customers relative to the location of connection, and type of protection system used on the Idaho Power transmission system.

The zone of protection refers to the area in Idaho Power's system where the interconnection customer's facility must provide fault protection. When a fault occurs, protective relays are to cause the isolation of the interconnection customer's facilities from Idaho Power's system. If there are any Idaho Power customers connected to the system in the zone of protection, the protection system is designed so that the service to those customers is not diminished by the addition of the interconnection customer's facilities. This includes the amount of delay in automatic testing by Idaho Power's equipment following a fault.

There are many options for providing the protective relay system for the zone of protection. These options will affect the up-front expense and the reliability of the interconnection customer's facilities. The use of pilot relaying or direct transfer trip communication may increase the expense to the interconnection customer. The protective relays at the interconnection customer's facility will need to be set to detect any fault in the zone of protection and to isolate the interconnection customer's generator from Idaho Power's system with no delay.

Line relays must be set to have overlapping zones of protection. Line protection schemes must be able to distinguish between normal load, inrush, and fault currents. Multiple terminal lines become even more complex to protect. Existing relay schemes may have to be reset, replaced, or augmented with additional relays at the interconnection customer's expense to coordinate with the interconnection customer's new facility.

Higher voltage interconnections require additional protection due to the greater potential for adverse impact to system stability, and the greater number of customers who would be affected. The acceptability and additional requirements of these interconnection proposals shall be determined by Idaho Power on a case-by-case basis.

16. GENERATION INTERCONNECTION PERFORMANCE REQUIREMENTS

All generating sources shall comply with all Idaho Power design requirements and applicable FERC, WECC and/or NERC policies, criteria, and standards, including:

- NERC TPL Planning Standards TPL–001 through TPL–004, current versions
- WECC and NERC Modeling, Data and Analysis (MOD) Standards, current versions
- NERC VAR-002, *Generator Operation for Maintaining Network Voltage Schedules,* current version
- ANSI Standards C50.10 and C50.13, regarding waveform and telephone interference
- WECC TPL-001-WECC-CRT, *System Performance Criterion,* current version
- WECC Standard VAR-501-WECC, *Power System Stabilizer,* current version

All generating plants are required to remain in-service during three-phase faults with normal clearing and single line-to-ground faults with delayed clearing, as well as during the subsequent post-contingency period unless clearing the fault effectively clears the generator from the system. The clearing time will be determined by and documented by Idaho Power on a location-by-location basis. If determined necessary by Idaho Power, generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

The generating unit(s) must meet all applicable American National Standards Institute (ANSI) and Institute of Electrical and Electronic Engineers (IEEE) standards. The prime mover, generator, and plant auxiliary equipment should also be able to operate within the full range of voltage and frequency excursions that may exist on the Idaho Power system without damage. To enhance system stability during a system disturbance, the generating unit must be able to operate through the specified frequency ranges for the time durations listed in the table below.

Pickup (hertz)	Time Delay (seconds)
61.7	0
61.6	30
60.6	180
59.4	180
57.8	7.5
57.3	0.75

16.1 Reactive & Voltage Control

In general, facilities capable of operating in the automatic voltage control mode are required to do so with the voltage sensed electrically at the point of interconnection. Unless exempted by Idaho Power, each generating interconnection shall maintain the generator voltage or reactive power schedule provided by Idaho Power. When a generator's AVR is out-of-service, the generation interconnection shall use an alternative method to control the generator reactive output to meet the voltage or reactive power schedule provided by Idaho Power. When instructed to modify voltage, the generation interconnection shall comply or provide an explanation of why the schedule cannot be met. Generation interconnections shall notify Idaho Power of a status change in the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. Generation interconnections shall notify Idaho Power within 30 minutes of becoming aware of a change in reactive capability due to factors other than the previously described status changes.

The generation interconnection must have equipment capable of receiving an analog setpoint, via DNP 3.0 from Idaho Power for voltage control. The setpoint will be the desired voltage level as measured at the interconnect bus.

16.2 Synchronous Generators

16.2.1 Synchronizing Relays

Synchronous generators and other generators with standalone capability must use one of the following methods to synchronize with the Idaho Power system:

1. Automatic Synchronization (ANSI Device 25)

   The automatic synchronizing relay must have a slip frequency-matching window of 0 to 0.2 Hz, a voltage-matching window of ± 10 percent or less, a phase angle-acceptance window of ± 10 degrees or less, and breaker-closure time compensation. The automatic synchronizing relay sends a close signal to the breaker after the above conditions are met. For an automatic synchronizer which does not have breaker-closure time compensation, a tighter frequency window (± 5 degrees) with a one-second time-acceptance window shall be used to achieve synchronization within ± 10 degrees phase angle.

2. Manual Synchronization with Synchroscope and Synch Check (ANSI Device 25) Relay Supervision

   The synch check relay must have a voltage-matching window of ± 10 percent or less and a phase angle-acceptance window of ± 10 degrees or less.

   Generators with greater than 1,000 kW aggregate nameplate rating must have automatic synchronizing relay or automatic synchronizer.

16.2.2 Frequency/Speed Control

Unless otherwise specified by Idaho Power, a governor shall be required on the prime mover to enhance system stability. Governor characteristics shall be set to provide a five percent droop characteristic (a 0.15 Hz change in the generator speed shall cause a five percent change in the generator load). Governors on the prime mover must be operated unrestrained to help regulate Idaho Power's system frequency.

16.2.3 Excitation System Requirements

An excitation system is required to regulate generator output voltage.
Static systems shall have a minimum ceiling voltage of 150 percent of rated full-load field voltage with 70 percent of generator terminal voltage and a maximum response time of two cycles (0.033 seconds).

Rotating systems shall have an ANSI voltage response ratio of 2.0 or faster.
Excitation systems shall be capable of responding to the full generator reactive capability in both the buck and boost directions. Under certain conditions, Idaho Power may grant an exemption for generation facilities which have excitation systems not meeting these requirements. Requests for exemption should be sent to Idaho Power account manager.

16.2.4 Voltage Regulator

The regulator must be able to maintain the generator voltage under steady-state conditions without hunting and within ± 0.5 percent of any voltage level between 95 percent and 105 percent of the rated generator. The point of voltage sensing should be at the same point as the Idaho Power revenue metering. As determined by the Idaho Power Control Center(s), the generator shall be operated at either a voltage or a power factor schedule.

At various times, the generating facility may also be requested by the Idaho Power Control Center(s) to produce more or less reactive power from that indicated on the regular schedule in order to meet the system needs.

16.2.5 Power-Factor Controller

The controller must be able to maintain a power-factor setting within ± 5 percent of the setting at full load at any set point between 95 percent lagging and 95 percent leading. In addition, all power-factor controllers for synchronous generators greater than 1 MW must have programmable capability to vary hourly settings.

16.2.6 Power-System Stabilizer (PSS)

Generators with properly tuned and calibrated PSS provide damping to electric power oscillations. Such damping improves stability in the electrical system and may also prevent an individual generator from unnecessary tripping. The current WECC policy requires that the PSS be an integral part of the voltage regulator and be incorporated into the excitation systems for all new generating units with suitable excitation systems.

The following criteria shall be used to determine when a PSS shall be installed on a synchronous generator, regardless of ownership, connected to the transmission system (by generator step-up transformer to 60 kV or higher voltage):

1. A PSS shall be installed on every existing synchronous generator that is larger than 75 MVA and is equipped with a suitable excitation system as defined in the WECC report, Criteria to Determine Excitation System Suitability for PSS available from the WECC web site.

2. A PSS shall be installed on every existing synchronous generator larger than 30 MVA or part of a complex that has an aggregate capacity larger than 75 MVA, or if the excitation system is updated so that it becomes a suitable excitation system as defined in the report mentioned in 1 above. This section applies to all machines whose excitation system is updated at any time after November 18, 1993.

3. A PSS shall be installed on every synchronous generator that is larger than 30 MVA or part of a complex that has an aggregate capacity larger than 75 MVA and is equipped with suitable excitation systems as defined in paragraph 1 and is commissioned after November 18, 1993.

4. A PSS is not required on a station service generator.

When a generator equipped with a functional PSS is online, the PSS shall be in operation except for the following reasons:

1. Maintenance and testing.

2. PSS exhibits instability due to nonstandard transmission line configuration.

3. PSS does not operate properly due to a failed component.

4. Unit is operating in the synchronous condenser mode (very near zero power level).

5. When a unit is generating less power than its design limit for effective PSS operation.

6. When a unit is passing through a range of output that is a known "rough zone."

The aggregate MVA of the synchronous machines online and equipped with a functioning PSS shall not fall below the level identified in the most recent power system stabilizer study commissioned by the WECC.

When a synchronous generator equipped with a PSS is operating in the pump mode (P/G unit) and is connected to a transmission system such that the PSS does not produce negative damping, the PSS should be in service.

PSS equipment shall be tested and calibrated in conjunction with AVR testing and calibration. This will be done as often as is necessary to maintain reliable PSS performance in accordance with WECC *PSS Tuning Criteria*. PSS recalibration must be performed if AVR response parameters are modified. When a PSS is taken out of service because of a failed component, the party responsible will be expected to perform the needed repairs (or replacement) in a responsible and timely manner.

A PSS is not required for a synchronous condenser.

16.3 Inverter-Based Resources (IBRs)

In accordance with NERC recommendations[2][3][4] inverter-based resources (IBR) connecting to Idaho Power's bulk electric system shall meet the performance requirements outlined in the following table.

[2] North American Electric Reliability Corporation, NERC. "Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources." NERC, September 2019

[3] North American Electric Reliability Corporation, NERC. "Reliability Guideline: BPS-Connected Inverter-Based Resource Performance." NERC, September 2018

[4] North American Electric Reliability Corporation, NERC. "Odessa Disturbance Texas Events: May 9, 2021, and June 26, 2021, Joint NERC and Texas RE Stagg Report." NERC, September 2021

Topic	Performance Requirement
Momentary Cessation	IBRs shall continuously inject current within the "No Trip Zone" of the currently effective version of PRC-024 and PRC-029 when effective. Momentary cessation may be required by Idaho Power based on system studies that show the need to mitigate potential local reliability or controls-related stability issues.
Phase Jump Immunity	Interconnection customers of IBRs shall provide Idaho Power documentation outlining the response that the IBR will have to instantaneous changes in phase (either due to fault events or switching events). The IBR plant shall ride through positive-sequence phase angle changes within a sub-cycle-to-cycle time frame of the applicable voltage of less than or equal to 25 electrical degrees (see IEEE 2800).
Capability Curve	Interconnection customers of IBRs shall provide Idaho Power a composite capability curve that includes the overall active and reactive capability of the resource as measured at the Point of Measurement (POM).[5] This includes a complete P-Q graph (or table of data representing these data points) at nominal voltage. Note that the minimum reactive capability – Q versus P for active power injection shall comply with IEEE 2800.
Active Power Frequency Controls	The primary frequency response (PFR) function and overall response capability of an IBR plant shall meet the specified performance requirements as specified in IEEE 2800. An IBR plant shall meet the underfrequency fast frequency response (FFR) performance requirements as specified in IEEE 2800. Utilization of FFR capability of IBR plant shall not be enabled by default.

[5] This is the "high-side of the generator substation" transformer, according to FERC Order No. 827

Topic	Performance Requirement
Transient Overvoltage Ride-Through	The intent of transient overvoltage ride-through requirements is to help ensure that the IBR plant does not trip during switching events in the TS. An IBR unit should continue to inject current, but it does not have to respond to transient overvoltage, i.e., enter reactive priority mode and/or change magnitude of current output. See IEEE 2800 for specific requirements.
Positive Damping Ratio	0.3 or better

16.3.1 Miscellaneous

The requirements specified in this standard are intended to apply over the lifetime of the IBR plant. When the transmission system operating and network conditions change significantly enough that changes in the IBR plant become necessary to reliably operate the IBR plant to support, or not degrade, transmission system reliability, equitable remedy measures shall be coordinated between the transmission system owner, transmission system operator, and the IBR owner and operator.

Examples for significant TS operating and network condition changes are new plants interconnecting close to an IBR plant, installation of new equipment by the TS owner, and changes in the short-circuit ratio (SCR) at the reference point of applicability.

This standard does not address effects of single-pole tripping and reclosing employed on the transmission system on performance of IBRs. The transmission system owner may specify additional performance requirements for satisfactory operation of IBR plants during single phase tripping and reclosing events.

The IBR owner shall inform transmission system owner / transmission system operator of any such environmental limitations: extreme temperature impacts on mechanical or electrical components (including battery capacity and component ratings), extreme wind impacts on mechanical or structural components, seismic impacts on mechanical, structural, or electrical components, etc.

The IBR plant shall, in a secure way, provide a local IBR communication interface with bi-directional communication capability, and shall be capable of securely providing real-time operational information of its status, mode of operation, and several steady-state, dynamic, and transient measurements.

The IBR plant shall provide the capabilities of the following mutually exclusive operating modes of reactive power control functions:

1. Voltage control
2. Power factor control

3. Reactive power set point control

The IBR plant shall be capable of activating each of these modes one at a time. The POM control mode shall be voltage control by default mode of the installed IBR plant unless otherwise specified by the TS operator.

17. CLOSE-OUT REQUIREMENTS

The interconnection customer's interconnection facilities shall be designed and constructed in accordance with good utility practice.

Within 120 calendar days after the commercial operation date, unless both parties agree on another mutually acceptable deadline, the interconnection customer shall deliver to the transmission provider "as-built" drawings, information, and documents for the interconnection facility, including:

- EMT, Power Flow, and Dynamic models,
- A one-line diagram,
- A site plan showing the interconnection,
- Elevation drawings showing the layout of the interconnection facility,
- A relay functional diagram, and
- The facilities connecting the large generating facility to the step-up transformers and the interconnection facility, and the impedances (determined by factory tests) for the associated step-up transformers and the large generating facility.

If applicable, the interconnection customer shall also provide the transmission provider with specifications for:

- The excitation system,
- Automatic voltage regulator,
- Large generating facility protection and control settings,
- Transformer tap settings,
- Communications facilities, and
- Transmission facilities.

Additionally, the interconnection customer shall provide reports documenting generating unit baseline and model validation testing, per applicable WECC and NERC criteria, to Idaho Power's System Planning:

Idaho Power System Planning
1221 W. Idaho St.
Boise, ID 83702
CompliancePlanning@idahopower.com

18. REVISION HISTORY

Section 1: Definitions

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report

Section 2: Introduction

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report

Section 3: Interconnection Request

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report

Section 4: Interconnection Studies

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report

Section 5: Generation Interconnection Model Requirements

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report
10/02/23	Planning	SWL	Added EMT Model Requirements as Section 5.4
06/25/24	Planning	TRS	Added reference to PRC-029

Section 6: Interconnection Facility Documentation

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report

Section 7: Interconnection Coordination

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report

Section 8: Interconnection Customer Requirements

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report

Section 9: Ownership Policy and Operation of Interconnection Equipment

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report

Section 10: Revisions and Updates

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report

Section 11: Transmission Capability

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report

Section 12: General Provisions

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report

Section 13: Transmission Interconnection Metering Requirements

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report
10/02/2023	Metering	SWL	Added GI Metering Standards (from Methods & Materials group) as Section 13
06/25/2024	Metering	SWL	Revisions to Loss Compensation, Multiple Generation and Energy Storage, and Exhibit A

Section 14: Telecommunication Requirements for Facility Interconnection

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report

Section 15: Protection and Control Policy

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report

Section 16: Generation Interconnection Performance Requirements

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report
06/25/24	Planning	TRS	Added reference to PRC-029

Section 17: Close-Out Requirements

Date	Department	Initials	Summary of Changes
07/26/23	Planning	SWL	Initial Report