Generator Interconnection Facilities Restudy Report

for the

130 MW [redacted] Project

for

[redacted]

in

Bingham County, Idaho

June 7, 2024

FACILITIES RESTUDY REPORT (RFSR)

1. General Facility Description

[redacted] (Interconnection Customer) has stated that the proposed project will consist of a 151 MVA solar photovoltaic and 147 MVA battery energy storage system (BESS) and connect to the [redacted] bus at Idaho Power Company's (IPC) Pingree Station in Bingham County, Idaho. The total project output as studied is 130 MW.

Contact Information for Interconnection Customer is as follows:

[redacted]

Following execution of the Large Generator Interconnection Agreement (LGIA) for Network Resource Interconnection Service (NRIS), senior-queued project GI #580 in the electrically relevant area withdrew from Idaho Power's GI queue. This prompted a System Impact Restudy (RSIS) and Interconnection Facilities Restudy (RFS) of GI #654. This report documents the results of the RFS for GI #654.

An amendment to the executed Standard Large Generator Interconnection Agreement (LGIA) under IPC's Open Access Transmission Tariff (OATT) between Interconnection Customer and IPC (Transmission Provider) for the 130 MW [redacted] Project, specifically Generator Interconnection Project #654 (Project), will be prepared. The LGIA and associated amendment will be a definitive agreement that contains terms and conditions that supersedes this RFSR.

Project Queue and Affected Systems:
The Project has applied to connect to Idaho Power's transmission system for an injection of 130 MW at a single Point of Interconnection (POI) at [redacted] at IPC's Pingree Station (PNGE) [redacted] bus.

If a senior-queued project that is responsible for providing additional transmission capacity should withdraw from the queue, a junior-queued project that may have been relying on at least a portion of any "surplus" capacity may then be faced with additional project costs for transmission capacity additions of their own. As of the date of this report, there are projects in the queue (GI #558, GI #573, GI #623, GI #633, and GI #641) ahead of the Project for which costs related to transmission capacity upgrades or additions could be passed on to the Project should changes be made to their queue position or generation output.

The recommended upgrades for GI #558, GI #573, GI #623, GI #633, and GI #641 were assumed to be completed prior to the interconnection of the Project.

The following Transmission Provider planned system improvements were assumed in service:

- Boardman to Hemingway 500kV transmission line (Q2 2027)

- 50% series capacitance compensation on the Kinport to Midpoint 345kV transmission line (2025)
- Midpoint Substation T502 500:345kV transformer (2025)
- Hemingway to Bowmont 230kV transmission line (2025)
- Bowmont to Hubbard 230kV transmission line (2026)

There are identified Transmission Provider planned system improvements that are required to be completed prior to the interconnection of this Project. There are additional Transmission Provider planned system improvements that are required specifically for grid-charging capability. Details on the contingent facilities identified are in Appendix B.

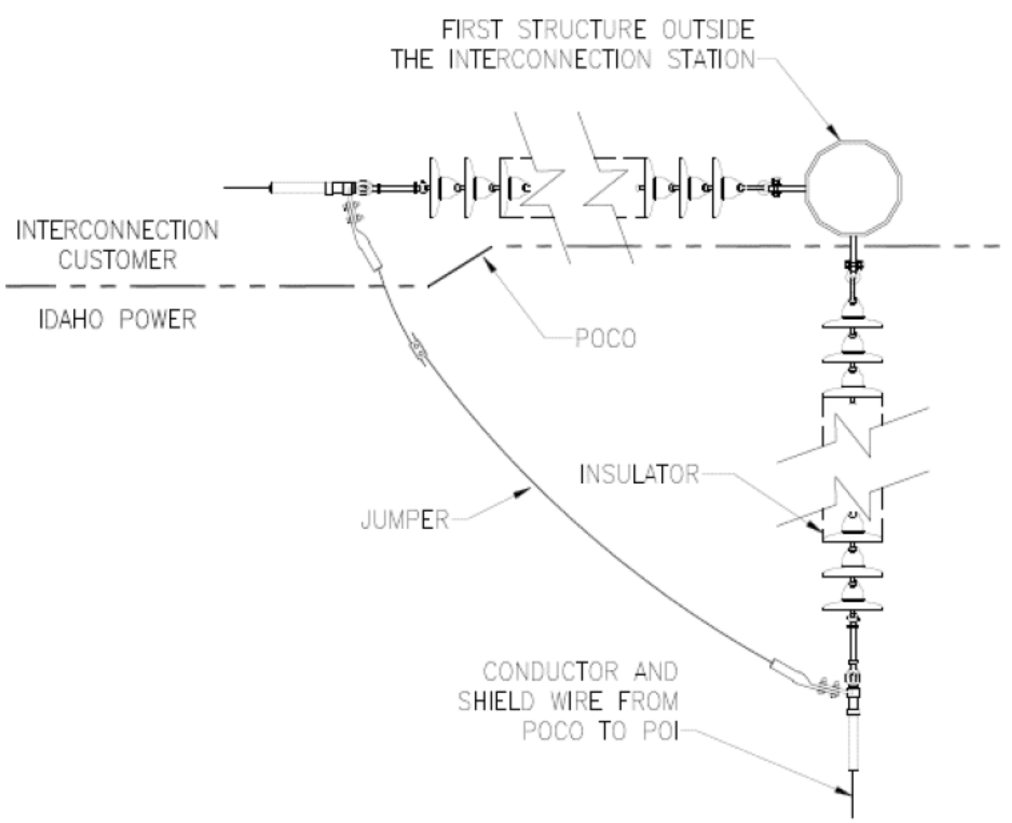
For the above and other reasons, the cost estimates included in this RFSR are estimates only, are based on currently known or assumed facts that may not be accurate or materialize, and are subject to change.

1.1 Interconnection Point

The Interconnection Facilities are located in IPC's Eastern region in Township [redacted], Range [redacted] and Section [redacted]. The Point of Interconnection (POI) for the Project will be on the bus near air-break switch [redacted], electrically between [redacted] at IPC's [redacted] Pingree Station. A drawing identifying the POI is attached as Exhibit 1.

1.2 Point of Change of Ownership

The Point of Change of Ownership (POCO) for the Project will be at the first structure outside the interconnection station. The structure at the POCO will be part of the Interconnection Customer's Interconnection Facilities. The jumper will be part of IPC's Interconnection Facilities. The following drawing provides generic information and standard requirements for the POCO.



Note the following related to the POCO:

- The first structure outside the interconnection station shall be designed as follows:
    - Vertical construction
    - 90-degree max line angle
    - Steel
    - IPC phase spacing
- Interconnection Customer's OPGW shall terminate at a splice box on the structure.
- Interconnection Customer shall inform IPC of the conductor size.
- IPC and Interconnection Customer shall coordinate phase configuration (e.g., 321, 213, etc.).
- Insulator parts shown in the diagram are for representation only; actual parts used will be dependent on final design.

1.3 Interconnection Customer's Facilities

1.3.1 Interconnection Customer's Interconnection Facilities

Interconnection Customer's Facilities are located approximately [redacted] away from IPC's Interconnection Facilities. The Interconnection Customer will install disconnect switches, distribution collector system, transformers, controllers, appropriate grounding measures, and associated auxiliary equipment. The main step-up transformer is [redacted] and should provide an adequate ground return path for transmission line protection/relaying.

Interconnection Customer will build [redacted] facilities to the POCO, including a gen-tie line with a minimum 24-count OPGW from Interconnection Customer's Interconnection Facilities to Transmission Provider's Interconnection Facilities. Interconnection Customer is responsible to mirror IPC's System Protection to include dual SEL-411L installation for protection of the interconnection intertie. A plant controller will be used to control the inverter system and to implement smart inverter functionality for operating the Project within a voltage range and power factor specified by IPC at the POI.

1.3.2 Generating Facilities

Interconnection Customer will install solar arrays, batteries, and inverters.
Interconnection Customer's Generating Facility will be constructed as follows:

1. The photovoltaic inverter system will comprise of [redacted] PV inverters
2. The BESS inverter system will comprise of [redacted] inverters

The above-referenced inverters, or equivalent inverters that have the same specifications and functionality as stated above must be utilized. If a different inverter is utilized that has different specifications and functionality than that which was studied, then additional study and/or equipment may be necessary.

The BESS component of the Project was studied charging from the grid in steady state under N-0 (no contingencies) conditions, which resulted in an overload of the [redacted] and [redacted] transmission lines. The Network Upgrades listed in Section 5.4 of this RFSR and contingent Transmission Provider planned system improvements listed in Appendix B, Table B2 are required to mitigate the overload during charging and will be required to be completed in order for the BESS to charge from the Idaho Power Transmission System.

There may be times during the year where system load in the local area will prevent charging of the BESS at full capacity (e.g., a forced outage that would require Idaho Power to curtail charging). The POI is on the radial [redacted] line; during summer months, the load at [redacted] ranges from [redacted] and remains higher than [redacted] for weeks at a time. Should the Project require non-curtailable charging of the energy storage device, then Point-to-Point firm transmission service from the energy market to the BESS and from the Project to the point of delivery would be needed.

1.4 Other Facilities Provided by Interconnection Customer

1.4.1 Telecommunications

Interconnection Customer is not responsible for any third-party communication circuits for IPC's Interconnection Facilities. Any additional telecommunication requirements will be the sole responsibility of Interconnection Customer.

1.4.2 Ground Fault Equipment

Interconnection Customer will install transformer configurations that will provide a ground source to the transmission system.

1.4.3 Generator Output Limit Control

Interconnection Customer will install equipment to receive signals from IPC Load Serving Operations for Generation Output Limit Control (GOLC)—see Section 3 Operating Requirements and Appendix A. IPC's recommended method of communication for GOLC is via fiber between IPC's Interconnection Facilities and the Project.

1.4.4 Local Service

Interconnection Customer is required to take local service as an IPC retail customer. Interconnection Customer is responsible to arrange for local service to their site and to coordinate such requirements with IPC so that local service can be provided in accordance with the provisions contained within the applicable service schedule. The service schedule and functional settlement will be determined during construction of the Project.

1.4.5 Site Work

None required.

1.4.6 Monitoring Information

If Interconnection Customer requires the ability to monitor information related to the IPC breaker/relay (i.e., Mirrored Bits) in IPC's Interconnection Facilities, they are required to supply their own communications circuit. The fiber communication circuit used for GOLC is acceptable.

1.4.7 *Meteorological Data*

In order to integrate the solar energy into the IPC system and operate IPC's solar forecasting tool, Interconnection Customer must provide solar irradiation and weather data from the Project's physical location to IPC via real-time telemetry in a form acceptable to IPC. The associated cost for obtaining this data is Interconnection Customer's responsibility.

The data must be provided at 10 second intervals and consist of:

1. Global Horizontal Irradiance
2. Plane of Array Irradiance
3. Ambient Temperature
4. Wind Speed and Wind Direction
5. Relative Humidity

The installed instruments must equal or exceed the specifications of the following instruments:

- *Temperature and Relative Humidity*: R.M Young Relative Humidity and Temperature Probe Sensors Model 41382
- *Wind*: R.M Young Wind Monitor Model 05103
- *Pryanometer:* Apogee Instruments Model SP-230

1.4.8 *Generator Technical Information & Drawings*

During Project design development, Interconnection Customer shall provide draft design prints containing technical information, including but not limited to impedances and equipment brand and models. After construction, Interconnection Customer shall submit to IPC all the as-built information, including prints with the latest approved technical information and commissioning test results in accordance with the timing requirements outlined in the GIA.

1.5 IPC's Interconnection Facilities

Transmission Provider's Interconnection Facilities are referred to hereafter as "IPC's Interconnection Facilities." IPC will install at the Pingree Station the last span of the Project's gen-tie line, including insulators, conductor, and associated hardware; [redacted] line bay with [redacted] steel dead-end structure; [redacted] circuit breaker; [redacted] air-break switches; [redacted] CTs; [redacted] PTs; [redacted] meter; and required foundations, bus, bus supports, relay protection equipment and fiber communication equipment to allow Interconnection Customer to interconnect the Project. IPC will install facilities up to the POCO.

IPC will install equipment to collect and transmit Phasor Measurement Unit (PMU) data to IPC. The data can be made available to Interconnection Customer on request.

The minimum acceptable PMU message rate is 30 messages per second. The minimum set of PMU measurement channels recorded at the POI is shown below. Additional or substitute channels may be required on a per case basis depending on the interconnection configuration and facility design details.

- Frequency

- Frequency Delta (dF/dt)
- Positive Sequence Voltage Magnitude
- Positive Sequence Voltage Angle
- Positive Sequence Current Magnitude
- Positive Sequence Current Angle

2. Estimated Milestones

These milestones will begin, and the milestone schedule referenced below will only be valid, upon receipt of funding from Interconnection Customer or its authorized third party no later than the date set forth in the ultimate LGIA for such payment. IPC will not commit any resources toward project construction that have not been funded by Interconnection Customer. Additionally, failure by Interconnection Customer to make the required payments as set forth in the ultimate LGIA by specified date(s) may result in the loss of milestone dates and construction schedules set forth below.

In the event Interconnection Customer is unable to meet dates as outlined in the ultimate LGIA, Interconnection Customer may request suspension of up to three years pursuant to Article 5.16 of the LGIA. Upon suspension of work pursuant to section 5.16 of the LGIA, the applicable construction duration, timelines, and schedules set forth in the ultimate LGIA shall be likewise suspended. The estimated milestones in the following table may be updated and revised for inclusion in the LGIA in light of subsequent developments and conditions.

Estimated Date	Responsible Party	Milestone
October 23, 2023	Interconnection Customer	Provided reasonable evidence to show one or more of the development milestones as per LGIP Section 11.3 has been achieved
November 2, 2023	Interconnection Customer	LGIA Executed
November 8, 2023	Interconnection Customer	Provided Certificate of Insurance
November 16, 2023	Interconnection Customer	Provided Demonstration of continued Site Control
November 17, 2023	Interconnection Customer	Full funding for project received in the form of a parental guaranty
November 24, 2023	Interconnection Customer	Project Initiation IPC received Notice to Proceed for design, procurement, and construction
December 2024	IPC	Contingent transmission system planned improvement for interconnection complete (see Appendix B, Table B1)
June 2024	IPC	Complete re-study
July 2024	Interconnection Customer	Execute GIA Amendment

Estimated Date	Responsible Party	Milestone
24 months following execution of GIA Amendment	IPC	Engineering and Design complete
36 months following execution of GIA Amendment	IPC	Long Lead Material procured/received
8 months prior to COD	Interconnection Customer	Provide updated EMT models to complete modeling in accordance with IPC's OATT Attachment O
6 months prior to IPC Commissioning	IPC	New generation modeled and submitted to the Western Energy Imbalance Market Failure to submit by given lead time will result in project delay
180 Calendar Days prior to Trial Operation	Interconnection Customer	Provide a completed copy of the Large Generating Facility data requirements contained in Appendix 1 of the LGIP per LGIA Article 24.3
180 Calendar Days prior to Initial Synchronization	Interconnection Customer	Provide initial specifications for the Interconnection Customer's Interconnection Facility per LGIA Article 5.10.1
90 Calendar Days prior to Initial Synchronization	Interconnection Customer	Provide final specifications for the Interconnection Customer's Interconnection Facility per LGIA Article 5.10.1
3 months prior to Initial Synchronization	Interconnection Customer	Provide notification of local Balancing Authority per LGIA Article 9.2
38 months following execution of GIA Amendment	IPC	Construction Complete
39 months following execution of GIA Amendment	IPC	Commissioning Complete Back feed power is available
5 days after switching request made to IPC Dispatch	Interconnection Customer	In-Service Date Switch at the POI can be closed to obtain back feed power
March 2027	IPC	Contingent transmission system planned improvements for grid-charging complete (see Appendix B, Table B2)
TBD	Interconnection Customer	Initial Synchronization Date Interconnection Customer Trial Operation begins
30 Calendar Days prior to COD	Interconnection Customer	Notify IPC of COD

Estimated Date	Responsible Party	Milestone
Prior to COD	Interconnection Customer	Provide as-built or as-tested performance data that differs from the initial Large Generating Facility data requirements contained in Appendix 1 of the LGIP per LGIA Article 24.3
TBD	Interconnection Customer	COD
Within 30 Calendar Days following COD	Interconnection Customer	Submit completed Appendix E of the LGIA confirming completion of Trial Operation and COD
120 Calendar Days following COD	Interconnection Customer	Provide as-built drawings, information, and documents for Interconnection Customer's Interconnection Facility per LGIA Article 5.11

Interconnection Customer has requested a Commercial Operation Date (COD) of December 15, 2027. IPC has developed the milestone dates in good faith considering many factors, including the requested COD, known long-lead times, and the schedule of other in-progress projects. The estimated milestone schedule captured in the following table may not align with the requested COD.

IPC does not warrant or guarantee the estimated milestone dates, which are estimates only. The milestone dates assume, among other things, that materials can be timely procured, labor resources are available, and that outages to the existing transmission system are available to be scheduled. Additionally, there are several matters, such as permitting issues and the performance of subcontractors that are outside the control of IPC that could delay the estimated COD. For purposes of example only, federal, state, or local permitting, land division approval, identification of Interconnection Facilities location, access to proposed Interconnection Facilities location for survey and geotechnical investigation, coordination of design and construction with the Interconnection Customer, failure of IPC's vendors to timely perform services or deliver goods, and delays in payment from Interconnection Customer may result in delays of any estimated milestone and the COD of the project. To the extent any of the foregoing are outside of the reasonable control of IPC, they shall be deemed Force Majeure events.

3. Operating Requirements

The Project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-2014 *IEEE Recommended Practices and requirements for harmonic Control in Electrical Power Systems* or any subsequent standards as they may be updated from time to time.

The Project will be subject to reductions directed by IPC Load Serving Operations during transmission system contingencies and other reliability events. When these conditions occur, the Project will be subject to Generator Output Limit Control (GOLC) and will have equipment capable of receiving an analog setpoint via DNP 3.0 from IPC for GOLC. GOLC will be accomplished with a setpoint and discrete output control from IPC to the Project indicating maximum output allowed. For more detail see Appendix A.

Low Voltage Ride Through: The Project must be capable of riding through faults on adjacent sections of the power system without tripping due to low voltage. The interconnection projects must meet or exceed the Low Voltage Ride-Through requirements as set forth in NERC Standard PRC-024.

Frequency Response Requirements: The Project must be capable of providing Primary Frequency Response for both positive and negative frequency deviations from 60Hz (+/- 0.036 Hz) with a droop of up to 5% for Bulk Electric System disturbances. Provided the Project meets the above Primary Frequency Response requirements, IPC shall not curtail the Project when such curtailments are caused by a need to comply with applicable Frequency Response reliability standards.

Momentary Cessation Requirements: Momentary cessation should not be used within the voltage and frequency ride-through curves specified in PRC-024. Use of momentary cessation is not considered "ride through" within the "No Trip" zone curves of PRC-024. The use of momentary cessation should be eliminated to the extent possible consistent with NERC's *Reliability Guideline for BPS-Connected Inverter-Based Resource Performance.*

Interconnection Customer will be able to modify power plant facilities on the Interconnection Customer side of the POI only if 1) there is no impact on the operation of the transmission or distribution system, 2) the generation facilities are electrically isolated from the system via the 101C switch, and 3) a terminal clearance is issued by IPC's Load Serving Operator.

4. Reactive Power

The Project is responsible to provide reactive power capability to have a power factor operating range of at least 0.95 leading (absorbing) to at least 0.95 lagging (supplying) at the high side of the generator substation over the range of real power output up to maximum output of the Project.

The Project must have equipment capable of receiving an analog setpoint, via DNP 3.0 from IPC for Voltage Control. IPC will issue an operating voltage schedule for the Project prior to the Project's In-Service Date. For more detail, see Appendix A.

5. Upgrades

5.1 Upgrades to Distribution System

No distribution upgrades are required.

5.2 Network Upgrades to Substations

[redacted] **Station**

Station will be modified to add a new line terminal to the [redacted] bus. The existing [redacted] line will be moved and re-terminated to the new line bay. The Project's [redacted] gen-tie line will be terminated on the existing bay. The work will include [redacted] steel dead-end structure, [redacted] CCVTs, [redacted] wave trap, a control building expansion, associated supports, foundations, relaying, communications, and control equipment will be installed in the station yard and building.

5.3 Network Upgrades to Transmission System

Re-termination of existing [redacted] line into [redacted] Station. The length of the retermination is estimated to be [redacted]. The re-termination will be constructed with [redacted] conductor, [redacted] OHGW (into sub bay), and [redacted] count OPGW. All structures will be engineered steel dead-ends on drilled pier foundations.

5.4 Network Upgrades Specific to Grid Charging

[redacted] **Substations**

The [redacted] Substations will each need to replace and upgrade [redacted] new line relay panel to accommodate the required transmission line differential protection scheme.

[redacted].

Rebuild existing [redacted] line from [redacted] station to [redacted] as double circuit [redacted]. The length of the rebuild is estimated to be [redacted] miles. The rebuild with be constructed with [redacted] conductor and one [redacted] 96 count OPGW. All structures will be engineered steel with tangents as direct embeds and dead-ends on drilled pier foundations. All structures will be designed for single circuit distribution, and it is assumed that any existing distribution will be transferred to new poles and is not part of this scope. It is assumed [redacted] quantities of [redacted]-phase switches will be needed on the line for this rebuild.

[redacted]

Rebuild existing [redacted] from [redacted] Station to [redacted] as single circuit [redacted]. The length of the rebuild is estimated to be [redacted] miles. Complete OPGW installation will be from [redacted] Station to [redacted] station and the length will be [redacted] miles. It is assumed the new OPGW installation from [redacted] to [redacted] station will not affect any existing structures so only new OPGW hardware and wire will be needed. The rebuild will be constructed with [redacted] conductor, one [redacted] OHGW (into sub bay), and [redacted] 96 count OPGW. All structures will be engineered steel with tangents as direct embeds and dead-ends on drilled pier foundations. All structures will be designed for single circuit distribution, and it is assumed that any existing distribution will be transferred to new poles and is not part of this scope.

6. Estimated Costs

The following good faith estimates are provided in 2024 dollars and are based on a number of assumptions and conditions. IPC does not warrant or guarantee the estimated costs in the table below, which are estimates only and are subject to change. Interconnection Customer will be responsible for all actual costs incurred in connection with the work to be performed by IPC and its agents, under the terms and subject to the conditions included in any LGIA executed by IPC and Interconnection Customer. Overhead costs cover the indirect costs associated with the Project and may vary from time to time.

The estimated cost below is required to be paid in full by Interconnection Customer, or other arrangements acceptable to IPC are made with IPC's Credit Department, prior to IPC commencing construction on the project.

Estimated Cost:

Description	Ownership	Cost Estimate
IPC Interconnection Facilities:		
Facilities between the Point of Change of Ownership and Point of Interconnection as described in Section 1.5	IPC	$526,057
Contingency 20%		$105,211
Overheads 3.5%		$22,094

Description	Ownership	Cost Estimate
TOTAL		**$653,362**
Network Upgrades to IPC Substation		
Upgrades at existing [redacted] Station as described in Section 5.2	IPC	$509,289
Contingency 20%		$101,858
Overheads 3.5%		$21,390
TOTAL		**$632,537**
Grid-Charging Network Upgrades to IPC Substations		
Upgrades at existing [redacted] Stations as described in Section 5.4	IPC	$624,535
Contingency 20%		$124,907
Overheads 3.5%		$26,230
TOTAL		**$775,672**
Network Upgrades to IPC Transmission System		
Upgrades as described in Section 5.3	IPC	$355,840
Contingency 20%		$71,168
Overheads 3.5%		$14,945
TOTAL		**$441,953**
Grid-Charging Network Upgrades to IPC Transmission System		
Upgrades as described in Section 5.4	IPC	$27,713,342
Contingency 20%		$5,542,668
Overheads 3.5%		$1,163,960
TOTAL		**$34,419,970**
GRAND TOTAL	**$36,923,494**	

Note Regarding Transmission Service:

This RFSR is a study of a request for Network Resource Interconnection Service (NRIS) as defined in Section 1 of IPC's LGIP. This RFSR identifies the facilities necessary to provide such service. NRIS in and of itself does not convey any right to transmission service or to deliver electricity to any specific customer or Point of Delivery.

Note Regarding LGIA:

This RFSR is a study and preliminary evaluation only and does not constitute, or form the basis of, a definitive agreement related to the matters described in this RFSR. Unless and until an LGIA amendment is executed by IPC and Interconnection Customer, no party will have any legal rights or obligations, express or implied, related to the subject matter of this RFSR.

Appendix A

Generation Interconnection Control Requirements

Interconnection Communications

All supervisory data points described in this Appendix A are to be communicated between Interconnection Customer and IPC via serial DNP3 protocol. The physical transport will be a single pair of fiber cables. A demarcation box housing a fiber termination panel will be accessible to both parties. Interconnection Customer is responsible for this fiber connection from their PLC or other controls equipment to the fiber termination panel inside the demarcation box. IPC will connect their supervisory control system to the same termination panel.

Generator Output Limit Control

The Project will be subject to reductions directed by IPC Load Serving Operations during transmission system contingencies and other reliability events. When these conditions occur, the Project will be subject to Generator Output Limit Control (GOLC) and will have equipment capable of receiving an analog setpoint via DNP 3.0 from IPC for GOLC. GOLC will be accomplished with a setpoint and discrete output control from IPC to the Project indicating maximum output allowed.

IPC requires interconnected Projects to accept GOLC signals from IPC's energy management system (EMS) when they are connected to IPC's transmission system.

The GOLC signals will consist of four points shared between the IPC EMS (via the IPC RTU) and the Interconnection Customer Generator Controller (SGC). The IPC RTU will be the master, and the SGC will be the slave.

- **GOLC Setpoint:** An analog output that contains the MW value the Interconnection Customer should curtail to, should a GOLC request be made via the GOLC On/Off discrete output Control point.

- **GOLC Setpoint Feedback:** An analog input feedback point must be updated (to reflect the GOLC setpoint value) by the SGC upon the SGC's receipt of the GOLC setpoint change, with no intentional delay.

- **GOLC On/Off:** A discrete output (DO) control point with pulsing Trip/Close controls. Following a "GOLC On" control (DNP Control Code "Close/Pulse On"), the SGC will run power output back to the MW value specified in the GOLC Setpoint. Following a "GOLC Off" control (DNP Control Code "Trip/Pulse On"), Interconnection Customer is free to run to maximum possible output.

- **GOLC On/Off Feedback:** A discrete input (DI) feedback point must be updated (to reflect the last GOLC DO Control Code received) by the SGC upon the SGC's receipt of the GOLC DO control, with no intentional delay. The feedback DI should latch to an OFF state following the receipt of a "GOLC OFF" control and it should latch to an ON state following the receipt of an "GOLC ON" control.

If a GOLC control is issued, it is expected to see MW reductions start within 1 minute and plant output to be below the GOLC Setpoint value within 10 minutes.

Voltage Control

IPC requires interconnected Projects to accept voltage control signals from IPC's EMS when they are connected to IPC's transmission system.

The voltage control will consist of one setpoint and one feedback point shared between the IPC EMS and the SGC.

- **Voltage Control Setpoint:** An analog output that contains the voltage the Interconnection Customer should target for plant operation. This setpoint will have a valid control range between 0.95 and 1.05 per unit (p.u.) of nominal system voltage.

- **Voltage Control Setpoint Feedback:** An analog input feedback point must be updated (to reflect the Voltage Control Setpoint) by the SGC upon the SGC's receipt of the voltage setpoint change, with no intentional delay.

The control will always be active; there is no digital supervisory point like the GOLC On/Off control above.

The voltage control system should operate at the voltage indicated by the voltage control setpoint with an accuracy of +/- 0.5%.

Interconnection Customer should supervise this control by setting up "reasonability limits" (i.e., configure a reasonable range of values for this control to be valid). As an example, they will accept anything in the valid control range (between 0.95 and 1.05 p.u.) but reject values outside this range. If they were fed an erroneous value outside the valid range, their control system would default to the last known, good value.

Frequency Response Control

IPC requires transmission-interconnected Projects to accept frequency response signals from IPC's EMS when they are connected to IPC's transmission system.

The frequency response will consist of one setpoint and one feedback point shared between the IPC EMS and the SGC.

- **Frequency Response Off/On:** A discrete output (DO) control point with pulsing Trip/Close controls. Following a "Frequency Response On" control (DNP Control Code "Close/Pulse On"), the SGC will reduce maximum power output to 95% of value in Maximum Park Generating Capacity data point. Following a "Frequency Response Off" control (DNP Control Code "Trip/Pulse On"), Interconnection Customer is free to run to maximum possible output.

- **Frequency Response Off/On Feedback:** A discrete input (DI) feedback point must be updated (to reflect the last Frequency Response DO Control Code received) by the SGC upon the SGC's receipt of the Frequency Response DO control, with no intentional delay. The feedback DI should latch to an OFF state following the receipt of a "Frequency Response OFF" control and it should latch to an ON state following the receipt of an "Frequency Response ON" control.

Auxiliary Data Points

Additional status points relating to local weather, equipment, and other supervisory information is required in accordance with the following Generation Interconnection Supervisory Data Table. This table includes a comprehensive list of data points to be sent and received via the fiber connection described in the Interconnection Communications portion of this Generation Interconnection Supervisory Data Requirements section.

Transmission-Interconnected Non-Wind Generation Interconnection Supervisory Data

Digital Inputs to IPC (DNP Obj. 01, Var. 2)			
Index	Description	State (0/1)	Comments:
0	GOLC Off/On (Control Feedback)	Off/On	Feedback provided by Interconnection Customer
1	FREQUENCY RESPONSE OFF/ON (Control Feedback)	Off/On	Feedback provided by Interconnection Customer
2	52A Interconnection Customer Main Breaker (if present)	Open/Closed	Sourced at substation
3	52A Interconnection Customer Capacitor Breaker (if present)	Open/Closed	Sourced at substation

Digital Outputs to Interconnection Customer (DNP Obj. 12, Var. 1)		
Index	Description	Comments:
0	GOLC Off/On	Control issued by IPC
1	Frequency Response Off/On	Control issued by IPC
2	EMS COMM Off/On	Control issued by IPC

Analog Inputs to IPC (DNP Obj. 30, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint Value Received (Feedback)	32767	-32768	TBD	TBD	MW	Provided by Interconnection Customer
1	Voltage Control Setpoint Value Rec'd (Feedback)	32767	-32768	TBD	TBD	kV	Provided by Interconnection Customer
2	Maximum Park Generating Capacity	32767	-32768	TBD	TBD	MW	Provided by Interconnection Customer
3	Ambient Temperature	32767	-32768	327.67	-327.68	DEG C	Provided by Interconnection Customer

Analog Inputs to IPC (DNP Obj. 30, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
4	Wind Direction	32767	-32768	327.67	-327.68	Deg from North	Provided by Interconnection Customer
5	Wind Speed	32767	-32768	327.67	-327.68	M/S	Provided by Interconnection Customer
6	Relative Humidity	32767	-32768	TBD	TBD	%	Provided by Interconnection Customer
7	Global Horizontal Irradiance	32767	-32768	TBD	TBD	W/M^2	Provided by Interconnection Customer
8	Plane of Array Irradiance	32767	-32768	TBD	TBD	W/M^2	Provided by Interconnection Customer
9	SPARE						
10	SPARE						
11	SPARE						
12	SPARE						
13	SPARE						
14	SPARE						
15	SPARE						
16	SPARE						
17	SPARE						

Analog Outputs to Interconnection Customer (DNP Obj. 41, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint	32767	-32768	TBD	TBD	MW	Control issued by IPC
1	Voltage Control Setpoint	32767	-32768	TBD	TBD	kV	Control issued by IPC
2	SPARE						
3	SPARE						
4	SPARE						
5	SPARE						

Analog Outputs to Interconnection Customer (DNP Obj. 41, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
6	SPARE						
7	SPARE						
8	SPARE						
9	SPARE						

Appendix B

The following tables B1 and B2 are a summary of the GI #654 contingent Transmission Provider planned system improvements as detailed in the GI #654 System Impact Restudy Report dated March 11, 2024.

Table B1: GI #654 contingent Transmission Provider planned system improvements required for interconnection

Transmission Provider planned system improvement	Estimated Date
Replace [redacted] transformer	December 2024

Table B2: GI #654 contingent Transmission Provider planned system improvement required only for grid-charging

Transmission Provider planned system improvement	Estimated Date
Idaho Power project to extend [redacted] transmission line from [redacted] Substation to [redacted] Substation	2030
Idaho Power project to build a new [redacted] transmission line from [redacted] Substation to [redacted] Station	March 2027