Generator Interconnection Facility Restudy Report

for the

150 MW [redacted]

for

[redacted]

in

[redacted], Idaho

Restudy
September 19, 2023

FACILITY RESTUDY REPORT (FSR)

150 MW [redacted]

Project #657

September 19, 2023

1. General Facility Description

[redacted] (Interconnection Customer) has stated that the proposed project will consist of a 150 MWac battery energy storage system (BESS) and connect to the [redacted] at Idaho Power Company's (IPC) [redacted] in [redacted], Idaho. The total project output as studied is 150 MW.

Contact Information for Interconnection Customer is as follows:

[redacted]

A Standard Large Generator Interconnection Agreement (LGIA) under IPC's Open Access Transmission Tariff (OATT) between Interconnection Customer and IPC – Delivery (Transmission Provider) for the 150 MW [redacted], specifically Generator Interconnection Project #657 (Project), will be prepared for this project. The LGIA will be a definitive agreement that contains terms and conditions that supersedes this FSR.

Project Queue and Affected Systems:
The Project has applied to connect to the Idaho Power's transmission system for an injection of 150 MW at a single Point of Interconnection (POI) at 138kV at IPC's [redacted] bus.

If an earlier queue project that is responsible for providing additional transmission capacity should drop out of the queue, a later queue 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 #530, GI #551, GI #557, GI #567, GI #568, GI #590, GI #604, GI #605, GI #619, GI #629, GI #636, GI #638, GI #639, GI #640, GI #643, and GI #646) ahead of the 150 MW [redacted] 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 #530, GI #551, GI #557, GI #567, GI #568, GI #590, GI #604, GI #605, GI #619, GI #629, GI #636, GI #638, GI #639, GI #640, GI #643, and GI #646 were assumed to be completed prior to the interconnection of the Project.

There is an identified Transmission Provider planned system improvement that was assumed in service for GI #657. This is required to be completed prior to the interconnection of this Project. Details on the contingent facilities identified are in Appendix B.

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

- Boardman to Hemingway 500kV transmission line (2026)
- 50% series capacitance compensation on the Kinport to Midpoint 345kV transmission line (2025)
- Midpoint Station transformer T502 500:345kV transformer (2025)
- Hemingway to Bowmont 230kV transmission line (2025)
- Bowmont to Hubbard 230kV transmission line (2025)
- Midpoint to Hemingway #2 500kV transmission line (2028)
- Reconductor Bowmont to Mora 138kV transmission line (2025)

For this and other reasons, the cost estimates included in this FSR are estimates only, and 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 [redacted] region in Township [redacted], Range [redacted] and Section [redacted]. The Point of Interconnection (POI) for the Project will be at the [redacted] on the bus between [redacted], [redacted], [redacted] and [redacted]. A drawing identifying the POI is attached as Exhibit 1.

1.2 Point of Change of Ownership

The Point of Change of Ownership for the Project will be on the Interconnection Customer's side of [redacted]. A drawing identifying the Point of Change of Ownership is attached as Exhibit 1.

1.3 Interconnection Customer's Facilities

The Interconnection Customer's Facilities are located approximately [redacted] away from IPC's Interconnection Facilities. The Interconnection Customer will install batteries, 41 SC4000UD-MV-US inverters, disconnect switches, distribution collector system, transformers, controllers, appropriate grounding measures, and associated auxiliary equipment. The main step-up transformer is a 100 / 133 / 167 MVA GSU unit. Interconnection Customer will build facilities to the Point of Change of Ownership. Interconnection Customer Interconnection Facilities include a fiber communication circuit to the Point of Change of Ownership.

The BESS component of the Project was studied storing energy from the Transmission System in steady state under N-0 (no contingencies) conditions and N-1 contingencies. The results show that there may be times during the year where system load in the local area will prevent storing energy from the Transmission System at the full capacity of the BESS; for example, a forced outage that would require IPC to curtail storing energy from the Transmission System. 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 battery and from the Project to the point of delivery would be needed.

1.4 Other Facilities Provided by Interconnection Customer

1.4.1 Telecommunications

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

1.4.2 Ground Fault Equipment

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

1.4.3 Generator Output Limit Control

The Interconnection Customer will install equipment to receive signals from IPC Grid 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 [redacted] and the Project.

1.4.4 Local Service

The Interconnection Customer is responsible to arrange for local service to their site, as necessary.

1.4.5 Site Work

None required.

1.4.6 Monitoring Information

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

1.4.7 Generator Technical Information & Drawings

Interconnection Customer shall provide draft design prints during Project design development containing technical information, like impedances, and equipment brand and models. After construction, the Interconnection Customer shall submit to IPC all the as-built information, including prints with the latest approved technical information and commissioning test results.

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 [redacted]: one ION 8650A meter, [redacted], [redacted] three CTs, three PTs, required foundations, bus, bus supports, fiber, and relay protection equipment to allow the Interconnection Customer to interconnect the Project. IPC will install facilities up to the Point of Change of Ownership.

IPC will install equipment to collect and transmit Phasor Measurement Unit (PMU) data to IPC. The data can be made available to the 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 construction 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 below 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 this Study by the date(s) specified below may result in the loss of milestone dates and construction schedules set forth below. In the event that the Interconnection Customer is unable to meet dates as outlined below, Interconnection Customer may request suspension of up to three (3) years pursuant to section 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 Appendix D shall be likewise suspended. Estimated milestones, which may be updated and revised for inclusion in the LGIA in light of subsequent developments and conditions, are as follows:

Estimated Date	Responsible Party	Estimated Milestones
TBD	*Interconnection Customer*	*Project Initiation (all three must be complete to initiate project):* • *LGIA Executed* • *IPC receives Notice to Proceed for design, procurement and construction.* • *Construction funding or arrangements acceptable to IPC are made with IPC's Credit Department*
8 months after Project Initiation Milestone Met	*IPC*	*IPC Engineering and Design Complete*
13 months after Project Initiation Milestone Met	*IPC*	*IPC Long Lead Material Procured/Received*
6 months prior to IPC Commissioning	*IPC*	*New generation must be modeled and submitted to the Western Energy Imbalance Market a minimum of 6 months prior to coming online, failure to submit by given lead time will results in project delay.*
16 months after Project Initiation Milestone Met	*IPC*	*IPC Construction Complete*
17 months after Project Initiation Milestone Met	*IPC*	*IPC Commissioning Complete* *Back feed power is available*
2025	*IPC*	*Transmission provider planned system improvements completed. (Appendix B)*

Estimated Date	Responsible Party	Estimated Milestones
5 days after switching request made to IPC Dispatch	*Interconnection Customer*	*Switch at the Point of Interconnection can be closed*
TBD	*IPC*	*Notification from IPC's Energy Contracting Coordinator confirming First Energy of Non-Firm Output*
TBD	*Interconnection Customer*	*Interconnection Customer testing begins*
TBD	*IPC*	*Notification from IPC's Energy Contracting Coordinator confirming Operation Date (pending all requirements are met) of Firm Network Resource Output*

Interconnection Customer has requested a Commercial Operation Date (COD) of 6/1/2025. The above milestone schedule do align with the requested COD; however, IPC has developed the above milestone dates in good faith considering many factors, including the requested COD, known long-lead times, and the schedule of other in-progress projects. IPC does not warrant or guarantee the foregoing estimated milestone dates, which are estimates only. These 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 Operation Date. 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 Operation Date 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 Grid 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: Generator 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 that Generator meets the above Primary Frequency Response requirements, IPC shall not curtail Interconnection Customer when such curtailments are caused by a need to comply with applicable Frequency Responsive 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 Pint of Change of Ownership with no impact upon the operation of the transmission or distribution system whenever the generation facilities are electrically isolated from the system via the air-break switch 101C and a terminal clearance is issued by IPC's Grid Operator.

4. Reactive Power

It is the Project's responsibility 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

The [redacted] will be modified to add two new line terminals, including the Interconnection Customer's new [redacted] interconnect line. The modification will include one double-bay steel dead-end structure, [redacted], [redacted], [redacted], and associated bus supports, foundations, relaying, communications, and control equipment will be installed in the station yard and a new control building. Removal of a circuit switcher, bus, bus supports and their foundations are part of the required station modification.

The [redacted] will be modified to upgrade an existing line terminal to include line breaker protection. The modification will include one single-bay steel dead-end structure, [redacted], [redacted], [redacted], and associated bus supports, foundations, relaying, communications, and control equipment will be installed in the station yard and existing control building.

5.3 Network Upgrades to Transmission System

Reconductor the existing [redacted] & [redacted] from the existing 1272 kcmil ACSR Bittern conductor with 1590 kcmil ACSR Lapwing conductor. Reconductor [redacted] at [redacted]. Rebuild single circuit 138kV slack span from [redacted] bay to existing [redacted] on [redacted]. Line length for [redacted] at [redacted] and [redacted] rebuild is [redacted] and [redacted] respectively.

All cost and schedule milestones associated with both of these transmission line plans are contingent on obtaining all required permits and easements.

6. Estimated Costs

The following good faith estimates are provided in 2023 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 the 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	$407,644
Contingency 20%		$81,529
Overheads 7.0%		$34,242
TOTAL		**$523,415**
Network Upgrades to IPC Substation		
Upgrades at the existing [redacted] and [redacted] Stations as described in Section 5.2	IPC	$2,593,783
Contingency 20%		$518,757
Overheads 7.0%		$217,878
TOTAL		**$3,330,418**
Network Upgrades to IPC Transmission System		
Upgrades as described in Section 5.3	IPC	$2,036,248
Contingency 20%		$407,250
Overheads 7.0%		$171,045
TOTAL		**$2,614,542**
GRAND TOTAL	**$6,468,375**	

Note Regarding Transmission Service:

This FSR is a study of a request for Network Resource Interconnection Service. This FSR identifies the facilities necessary to provide such service. Network Resource Interconnection Service 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 FSR 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 FSR. Unless and until a LGIA 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 FSR.

Appendix A

Generation Interconnection Control Requirements

A.1 Generator Output Limit Control (GOLC)

A.1.1 IPC requires Interconnected Power Producers to accept GOLC signals from IPC's energy management system (EMS).

A.1.2 The GOLC signals will consist of four points shared between the IPC EMS (via the IPC RTU) and the Interconnection Customer's Generator Controller (SGC). The IPC RTU will be the master and the SGC will be the slave.

A.1.2.1 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.

A.1.2.1.1 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.

A.1.2.2 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"), the Interconnection Customer is free to run to maximum possible output.

A.1.2.2.1 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.

A.1.3 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.

A.2 Voltage Control

A.2.1 IPC requires Transmission-Interconnected Power Producers to accept voltage control signals from IPC's EMS when they are connected to IPC's transmission system.

A.2.2 The voltage control will consist of one setpoint and one feedback point shared between the IPC EMS and the SGC.

A.2.3 The setpoint will contain the desired target voltage 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.

A.2.4 The control will always be active, there is no digital supervisory point like the Curtail On/Off control above.

A.2.4.1 When a setpoint change is issued an Analog Input feedback point must be updated (to reflect the voltage control setpoint value) by the SGC upon the SGC's receipt of the voltage control setpoint change, with no intentional delay.

A.2.4.2 When a setpoint change is received by the SGC, the voltage control system should react with no intentional delay.

A.2.4.3 The voltage control system should operate at the voltage indicated by the setpoint with an accuracy of +/- 0.5% of the nominal system voltage.

A.2.5 The 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.

A.3 Generation Interconnection Data Points Requirements

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

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	SPARE						
4	SPARE						
5	SPARE						
6	SPARE						
7	SPARE						
8	SPARE						
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						
6	SPARE						
7	SPARE						
8	SPARE						
9	SPARE						

Appendix B

The following table B is a summary of the Transmission Provider planned system improvements that are required in service for GI #657, as detailed in the GI #657 System Impact Report dated July 2023.

Table B1: GI #657 Transmission Provider planned system improvements

Transmission Provider planned system improvements	Estimated Date
Idaho Power project to rebuild the [redacted] 138kV transmission line	2025