Generator Interconnection Facility Study Report

for the

100 MW [redacted]

for

[redacted]

in

[redacted]

May 05, 2023

FACILITY STUDY REPORT (FSR)

100 MW [redacted]
Project GI #624
May 5, 2023

1. General Facility Description

[redacted] ("Interconnection Customer") has stated that the proposed project will consist of 100 MW photovoltaic and battery energy storage system (BESS) in [redacted] Idaho and connect to the [redacted] bus at Idaho Power Company (IPC)'s [redacted] The total project output as studied is 100 MW. Interconnection Customer has requested a Commercial Operation Date (COD) of [redacted].

Contact Information for Interconnection Customer is as follows:

[redacted]

A Standard Large Generator Interconnection Agreement (the "LGIA") under IPC's Open Access Transmission Tariff (OATT) between Interconnection Customer and IPC (Transmission Provider) for the 100 MW [redacted], specifically Generator Interconnection Project #624 ("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:
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 #549, GI #551, GI #557, GI #567, GI #570, GI #588, GI #590, GI #604, GI #605, GI #614, GI #620, and GI #621) ahead of the 100 MW [redacted] for which costs related to transmission capacity upgrades or additions could be passed on to the 100 MW [redacted] should changes be made to their queue position or generation output.

There are planned system improvements that were assumed to be in service. Details on the contingent facilities identified are in Appendix B. The upgrades, which are associated with a planned Idaho Power [redacted], may take longer to construct than what is listed in Appendix B.

1.1 Interconnection Point

The Interconnection Facilities are located in IPC's Southern region in Township [redacted], Range [redacted] and Section [redacted]. The Point of Interconnection (POI) for the Project will be on the node between switch [redacted] and [redacted] on the Midpoint Substation 230kV bus. 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 air-break switch [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 immediately north of IPC's [redacted]. The Interconnection Customer will install solar arrays, batteries, inverters, disconnect switches, distribution collector system, transformers (including a main step-up transformer), appropriate grounding measures, and associated auxiliary equipment. The main step-up transformer is a 78.3/98/123 MVA, 230/34.5kV wye-grounded/wye-grounded, delta-tertiary 3-phase unit. Interconnection Customer will build 230kV facilities to the Point of Change of Ownership.

The Interconnection Customer's system will be constructed as follows:

1. The solar inverter system will comprise of 29 [redacted] Inverters, with each inverter having an apparent power rating of 4.2 MVA.
2. The BESS inverter system will comprise of 38 [redacted] Inverters, with each inverter having an apparent power rating of 3.2 MVA.
3. A plant controller will be used to control the inverter system(s) and to implement smart inverter functionality for operating the project within a voltage range and power factor specified by IPC at the Point of Interconnection.

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 Project is a combined solar and BESS generation project. It has been assumed the BESS will be charged via the solar output. The Interconnection Customer will need to demonstrate the operating procedures and control measures which prevents the BESS from being charged via IPC's transmission system.

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 the IPC's Interconnection Facilities 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 Property

There are no property transaction requirements related to IPC's interconnection facilities or network upgrades identified in this study.

The Interconnection Customer may be required to obtain transmission easements and/or transmission line crossing agreements from IPC depending on the designed path of the Interconnection Customer's 230kV generator tie line.

1.4.6 Site Work

No site work is required beyond that identified for network upgrades on property already owned by IPC. The identified [redacted] relocation will take place on land owned by IPC.

1.4.7 Monitoring Information

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

1.4.8 Meteorological Data

In order to integrate the solar energy into the IPC system and operate IPC's solar forecasting tool, the 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 the 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 [redacted]
- *Wind*: R.M Young Wind Monitor [redacted]
- *Pryanometer:* Apogee Instruments [redacted]

1.4.9 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

At the [redacted] IPC will install [redacted] revenue meter, [redacted] dead-end structures, [redacted] air-break switch, [redacted] CTs, required foundations and fiber communication 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 B shall be likewise suspended. Estimated milestones, which will 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
[DATE]	*Interconnection Customer*	*IPC receives Notice to Proceed for design, procurement and construction.* *Construction funding or arrangements acceptable to IPC are made with IPC's Credit Department*
24 months after construction funds received	*IPC*	*IPC Engineering and Design Complete*
30 months after construction funds received	*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.*
36 months after construction funds received	*IPC*	*IPC Construction Complete*
38 months after construction funds received	*IPC*	*IPC Commissioning Complete* *Back feed power is available*
Varies	*IPC*	*Contingent facilities completed. (Appendix B)*
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*

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. Generator Output Limit Control 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 Fast Frequency Response for both positive and negative frequency deviations from 60Hz (+/- 0.036 Hz) for Bulk Electric System disturbances. The required frequency response will be linear for a deviation of 0 to +/- 0.1 Hz, a response of 0% to 3% of generator capacity, with a maximum required response of 3% of generator's full capacity for as long as the generator is able to provide support or the frequency deviation is reduced to within stated limits, whichever occurs first. Provided that Generator meets the above Fast Frequency Response requirements, Company 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 Point of Interconnection with no impact upon the operation of the transmission or distribution system whenever the generation facilities are electrically isolated from the system via the [redacted] switch 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) and for all modes of operations (solar generation only, combined solar/BESS (charging and discharging), and BESS generation only).

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 at the time the LGIA is executed. For more detail see Appendix A.

5. Upgrades

5.1 Upgrades to the Distribution System

There are no required distribution upgrades.

5.2 Network Upgrades to Substations

[redacted] Yard

A new [redacted] line terminal will be built onto the existing breaker and a half bus design by building a new bus rung on the south side of the existing [redacted] yard. [redacted] circuit breakers on precast foundations, [redacted] air-break switches on drilled pier foundations, one set of CCVTs, one singe phase CCVT and one set of CTs on drilled pier foundations will be installed along with seven [redacted] 3-phase rigid bus support structures and [redacted] single-phase steel rigid bus structures all on drilled pier foundations. Install two dual SEL 411L protection panels and two SCADA panels in the existing control house. Install 100 feet of cable trench for communications and protection circuits into the existing control house. Reconfiguration of existing incoming [redacted] will require [redacted] dead-end structures to be installed inside of [redacted].

[redacted] Yard

The existing [redacted] yard will be removed and rebuilt approximately [redacted] to provide adequate space for the [redacted] bus expansion. The new [redacted] will require fencing, grading and land development as part of the build. Equipment to be installed at the new yard includes [redacted] breaker and [redacted] breakers on precast foundations. The existing [redacted] transformer will be moved to a new foundation in the relocated yard. A new control building will be installed to house the protection, battery, SCADA and communications equipment. The relocation of the [redacted] yard will be contingent on obtaining an outage window long enough to complete this work.

5.3 Network Upgrades to the Transmission System

Reroute [redacted] transmission lines ([redacted]) and build a new [redacted] line from the existing [redacted] into the relocated [redacted]. For the [redacted] lines, install approximately [redacted] and [redacted], using two deadend structures and two running angle structures. For the [redacted] line, install approximately [redacted], using two deadend structures. The new transmission line sections will also require four engineered steel mono poles to support the realignment.

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.

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	$368,500
Contingency 10%		$36,850
Overheads 8.25%		$33,441
TOTAL		**$438,791**
Network Upgrades to IPC Substation:		
Upgrades to [redacted] as described in Section 5.2	IPC	$6,441,524
Contingency 10%		$644,152
Overheads 8.25%		$584,568
TOTAL		**$7,670,244**
Network Upgrades to IPC Transmission:		
Upgrades to IPC transmission lines as described in Section 5.3	IPC	$905,095
Contingency 10%		$90,509
Overheads 8.25%		$82,137
TOTAL		**$1,077,741**
GRAND TOTAL	**$9,186,776**	

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	Ambient Temperature	32767	-32768	327.67	-327.68	DEG C	Provided by Interconnection Customer
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						
6	SPARE						
7	SPARE						
8	SPARE						
9	SPARE						

Appendix B

The following table B1 is a summary of the planned Idaho Power facility upgrades required and their anticipated completion date as detailed in the GI #624 System Impact Restudy Report dated February 10, 2023.

Table B1: : Idaho Power Planned Transmission Project Required by GI #624

Idaho Power Transmission Planned Projects	
Transmission Upgrades	**Anticipated Completion**
[redacted] transmission line	Q2 2026
50% series capacitance compensation on the [redacted] transmission line	2025
[redacted] transformer	2025
[redacted] transmission line	2025
[redacted] transmission line	2025