Interconnection Facilities Restudy Report

[redacted] #667

400 MW Solar and Energy Storage

Elmore County, ID

[redacted]

June 9, 2025

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1. Study Overview

1.1 Introduction

[redacted] (Interconnection Customer) has an executed Large Generator Interconnection Agreement (LGIA) with Idaho Power Company (IPC) for interconnection of the proposed 400 MW [redacted] #667 (Project) to IPC's Boise Bench to Midpoint #2 230kV transmission line ([redacted]) in Elmore County, ID ([redacted]). The LGIA is for Network Resource Interconnection Service (NRIS).

Following execution of the LGIA for the Project, IPC identified that the Interconnection Facilities Study Report (FSR) dated November 1, 2023 reflected an incorrect Point of Interconnection (POI) on the [redacted] transmission line ([redacted]). This Interconnection Facilities Restudy Report (RFSR) identifies the work required to interconnect the project at the correct POI on the requested Boise Bench to Midpoint #2 230kV transmission line ([redacted]) as reflected in the System Impact Study Report dated March 21, 2023 and shown in Exhibit 1, attached.

In accordance with Section 8.2 of IPC's Large Generator Interconnection Procedures (LGIP), this RFSR is specific to the Project and documents the basis for, and results of, the Facilities Restudy (RFS) for the Project. The RFSR provides a non-binding estimate of the cost of—and schedule for—equipment, engineering, procurement, and construction work required to connect the Project physically and electrically to the Transmission System. This report satisfies the RFS requirements of IPC's LGIP.

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. An LGIA amendment under IPC's Open Access Transmission Tariff (OATT) between Interconnection Customer and IPC for the Project will be prepared following finalization of this RFSR. The LGIA, as amended, will be a definitive agreement that contains terms and conditions that supersede this RFSR.

1.2 Study Assumptions

- For NRIS, additional studies to reduce or eliminate congestion may be required, and these studies may identify the need for additional upgrades. To the extent Interconnection Customer enters an arrangement for long term transmission service for deliveries from the Large Generating Facility to any point outside IPC's Transmission System, such request may require additional studies and upgrades for IPC to grant such request.

- Senior- and equally queued Interconnection Requests that were considered in this study are listed in Section 3.1. If any of these Interconnection Requests are withdrawn, IPC reserves the right to restudy this Project, and the results and conclusions could significantly change.

- The following IPC planned system improvements were assumed in service:
  - Boardman to Hemingway 500 kV transmission line (2027)
  - 50% series capacitance compensation on the Kinport to Midpoint 345 kV transmission line (2026)
  - Midpoint Substation transformer T502 500:345 kV transformer (2026)
  - Hemingway to Bowmont 230 kV transmission line (2026)
  - Bowmont to Hubbard 230 kV transmission line (2026)
  - Midpoint to Hemingway #2 500kV transmission line (2028)
- This report is based on information available at the time of study. Interconnection Customer is responsible to check IPC's OASIS site and website regularly for Generation Interconnection and Transmission System updates:
  - OASIS (https://www.oasis.oati.com/ipco/)
  - Planning and Electrical Projects (https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/)

1.3 No 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.

The battery energy storage system (BESS) component of this Project was studied for grid-charging. This RFSR identifies the facilities necessary to interconnect the Project such that grid-charging can be achieved. The grid-charging results do not convey any right to transmission service for, or constitute an agreement to allow, the BESS to charge from the grid. Additional agreements (e.g., Transmission Service Agreement or Battery Services Agreement) external to the Generation Interconnection study process must be sought prior to the Project commencing any grid-charging activities.

2. Interconnection Facilities and Upgrades

2.1 Interconnection Customer's Interconnection Facilities

General Facility Description

The proposed Project will consist of [redacted] MVA photovoltaic (PV) and [redacted] MVA battery energy storage (BESS) in Elmore County, Idaho and interconnect at two Points of Interconnection (POI) on IPC's Boise Bench to Midpoint #2 230kV transmission line ([redacted]) at approximately [redacted]. The net Project output at the POI as studied is 400 MW.

Interconnection Customer's Interconnection Facilities are defined in Section 1 of IPC's LGIP as all facilities and equipment located between the Generating Facility and the Point of Change of Ownership (POCO), including any modification, addition, or upgrades to such facilities and equipment. Interconnection Customer is responsible for funding and constructing Interconnection Customer's Interconnection Facilities, including the gen-tie line and facilities to the POCO.

Interconnection Customer's Interconnection Facilities are located in IPC's [redacted] region in Township [redacted], Range [redacted], and Section [redacted] ([redacted]) and are approximately [redacted] away from Transmission Provider's Interconnection Facilities (IPC's Interconnection Facilities). Interconnection Customer will install disconnect switches, distribution collector system, transformers, controllers, appropriate grounding measures, and associated auxiliary equipment.

The [redacted] main step-up transformers are [redacted] transformers. The proposed [redacted] transformers specified in the Project's single-line diagram dated July 31, 2023 should provide an adequate ground return path for transmission line protection/relaying.

Interconnection Customer will build facilities to the POCO, including two transmission lines with a minimum 24-count optical ground wire (OPGW) from Interconnection Customer's Interconnection Facilities to IPC's Interconnection Facilities. Interconnection Customer is responsible to mirror IPC's System Protection relays to include dual SEL-411L installation for protection of the interconnection intertie.

Point of Change of Ownership

The POCO for the Project will be at the first structure outside the interconnection station (POI Station) for each of the Project's two generation tie (gen-tie) lines. The structure at the POCO will be part of 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.

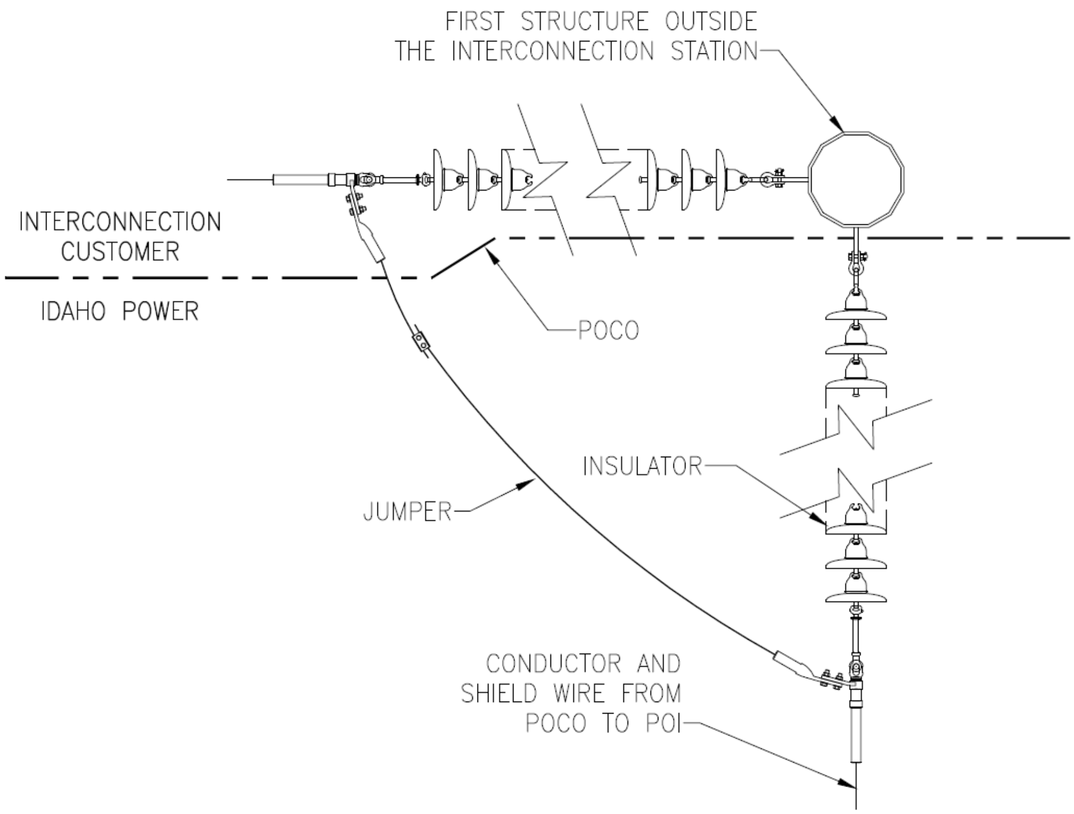

Figure 1
Generic Point of Change of Ownership (POCO) configuration.

Note the following related to the POCO:

- The first structure outside the POI Station shall be designed as follows:
    - Vertical construction
    - 90-degree max line angle
    - Steel
    - IPC phase spacing
- Interconnection Customer's OPGW shall terminate at an Interconnection Customer-provided 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.

2.2 Transmission Provider's Interconnection Facilities

Transmission Provider's Interconnection Facilities (IPC's Interconnection Facilities) are defined in Section 1 of IPC's LGIP as all facilities and equipment owned, controlled, or operated by IPC from the POCO to the POI, including any modifications, additions, or upgrades to such facilities or equipment. In accordance with Section 4.2.1 of IPC's LGIP, costs for IPC's Interconnection Facilities are directly assigned to Interconnection Customer and are not reimbursable.

Point of Interconnection

The Project's POIs will be at a new 230kV POI Station on Interconnection Customer's requested POI of IPC's Boise Bench to Midpoint #2 230kV transmission line ([redacted]) at approximately [redacted]. The preliminary configuration for the POIs is on IPC's side of air-break switches [redacted] and [redacted]. A drawing detailing the configuration is attached as Exhibit 2. This configuration will be finalized during construction, and the final configuration will be captured in an LGIA amendment, if necessary.

Metering

All metering for the Project will be installed, configured, and maintained in accordance with IPC's publicly posted Facility Interconnection Requirements for Transmission Systems, as may be updated from time to time.

IPC's Interconnection Facilities

To allow interconnection of the Project, IPC will install the following facilities up to the POCO:

- [redacted] primary metering packages
- [redacted] dead-end structures
- [redacted] air-break switches
- [redacted] line capacitance coupled voltage transformers (CCVT)
- [redacted] line current transformers (CT)
- Required foundations, bus, bus supports, and fiber communication equipment
- The last span of the [redacted] Project gen-tie lines, including insulators, conductor, and associated hardware

IPC will install equipment to collect and transmit Phasor Measurement Unit (PMU) data to IPC. The communication circuits required for this data transmission are described in Section 5.2 of this RFSR. The data can be made available to Interconnection Customer on request.

Table 1
Transmission Provider Interconnection Facilities

Facility Description	Unloaded Cost Estimate
Interconnection Facilities	$1,093,512
Last Span of Gen-tie	$61,749
TOTAL Unloaded Costs	**$1,155,261**

2.3 Substation Network Upgrades

Substation Network Upgrades are defined in Section 1 of IPC's LGIP as Network Upgrades that are required at the substation located at the POI; this includes all switching stations. This section includes both Substation Stand Alone Network Upgrades (SANU) and Substation Network Upgrades, the actual costs of which are reimbursable.

Substation Stand Alone Network Upgrades

SANUs are defined in Section 1 of IPC's LGIP as Network Upgrades that Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction.

The following Substation SANUs are required for this Project:

- A new fenced [redacted] ring bus POI Station
    - Approximately [redacted] pad
    - [redacted] entrance gates and driveway aprons
    - New [redacted] control building
    - [redacted] line bays
    - [redacted] circuit breakers
    - [redacted] air-breaks
    - [redacted] ground switches
    - [redacted] CCVTs
    - Associated bus supports, foundations, relaying, communications, and control equipment in the station yard and building

- [redacted] series capacitor bank with [redacted] bypass breaker[1]

Table 2
Substation Stand Alone Network Upgrades

Facility Description	Unloaded Cost Estimate
POI Station	$28,446,738

Substation Network Upgrades

No Substation Network Upgrades were identified for this Project.

2.4 System Network Upgrades

System Network Upgrades are defined in Section 1 of IPC's LGIP as Network Upgrades that are required beyond the substation located at the POI. This section includes both System SANU and System Network Upgrades, the actual costs of which are reimbursable.

System Stand Alone Network Upgrades

SANUs are defined in Section 1 of IPC's LGIP as Network Upgrades that Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction.

No System SANUs were identified for this Project.

System Network Upgrades

The following System Network Upgrades are required for this Project:

[redacted] Station

- [redacted] capacitor bank with [redacted] bypass breaker on the [redacted] transmission line ([redacted]) toward the new POI Station[2]

[redacted] Transmission Line ([redacted]) Cut-in at POI Station

- Cut in the [redacted] transmission line ([redacted]) [redacted] to the new POI Station
    - All structures will be three-pole designed steel guyed dead-end structures on direct embed foundations

[1] With the addition of GI #590, there is existing series compensation on the Boise Bench–Midpoint #2 line. With GI #667 connecting in the middle of the line, IPC needs to remove the series capacitor at the senior-queued GI #590 facility and split it into one segment at [redacted] (towards GI #667), and one segment at GI #667 (towards GI #590). This splitting is required so that the compensation does not exceed 100% for any line segment.
[2] See previous footnote.

- [redacted] Conductor
- [redacted] 96-count OPGW with 3/8" EHS steel shield wire

Table 3
System Network Upgrades

Facility Description	Unloaded Cost Estimate
[redacted] Station	$5,541,023
[redacted] Cut-in at POI Station	$818,241
TOTAL Unloaded Costs	**$6,359,264**

2.5 Distribution Upgrades

Distribution Upgrades are defined in Section 1 of IPC's LGIP as additions, modification, and upgrades to IPC's Distribution System at or beyond the POI to facilitate interconnection of the Generating Facility. In accordance with Article 11.3 of IPC's LGIA, costs for Distribution Upgrades are directly assigned to Interconnection Customer and are not reimbursable.

Note that the identified Distribution Upgrades do not include distribution facilities to support local service to Interconnection Customer's Interconnection Facilities, Generating Facility, auxiliary load, etc. See the Local Service portion of Section 5.2 of this RFSR for additional information on local service requirements.

The new POI Station will require 120/240V station service power. To provide this service, approximately [redacted] of new [redacted] overhead distribution line from a nearby existing distribution line will be required.

Table 4
Distribution Upgrades

Facility Description	Unloaded Cost Estimate
Local Service Distribution	$950,229

2.6 Estimated Costs

The following good faith estimates are provided in 2025 US 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 performed by IPC and its agents, under the terms and subject to the conditions included in any LGIA executed by IPC and Interconnection Customer. Costs for work being performed by Interconnection Customer and/or Affected Systems are not included.

There are identified contingent facility Network Upgrades and/or planned system improvements that are required to be completed prior to the interconnection of this Project. Details on the contingent facilities identified are in section 3.2 of this RFSR. For this 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.

Table 5
Estimated cost of Interconnection Facilities and Network Upgrades.

Description	Ownership	Cost Estimate
IPC Interconnection Facilities:		
Facilities between the POCO and POI as described in Section 2.2	IPC	$1,155,261
Contingency 20%		$231,052
Overheads 3%		$41,589
Total		**$1,427,903**
Stand-Alone Substation Network Upgrades:		
Stand Alone upgrades to POI Station as described in Section 2.3	IPC	$28,446,738
Contingency 20%		$5,689,348
Overheads 3%		$1,024,083
Total		**$35,160,168**
System Network Upgrades:		
Upgrades to Transmission System as described in Section 2.4	IPC	$6,359,264
Contingency 20%		$1,271,853
Overheads 3%		$228,934
Total		**$7,860,050**
Distribution Upgrades:		
Upgrades to Distribution System as described in Section 2.5	IPC	$950,229
Contingency 20%		$190,046
Overheads 10%		$114,027
Total		**$1,254,302**
	GRAND TOTAL	**$45,702,423**

3. Contingent Facilities and Affected Systems

3.1 Generation Interconnection Queue

Interconnection Customer has applied to interconnect the Project to IPC's transmission system for an injection of 400 MW at [redacted] POIs at 230kV at a new IPC 230kV POI Station on Interconnection Customer's requested POI of IPC's Boise Bench to Midpoint #2 230kV transmission line ([redacted]) at approximately [redacted].

If a senior- or equally queued Interconnection Request that is responsible for constructing Network Upgrades should withdraw from the queue or otherwise be terminated, junior- or equally queued Interconnection Requests in the electrically relevant area may be restudied and assigned additional Network Upgrades identified as necessary to facilitate their interconnection.

As of the date of this report, Interconnection Requests #530, #551, #557, #562, #567, #590, #605, #624, #625, #636, #639, #640, #656, #659, and #662 are senior-queued Interconnection Requests to the Project. The recommended upgrades for these senior-queued Interconnection Requests were assumed to be completed prior to the interconnection of the Project. Costs related to Network Upgrades could be passed on to the Project should changes be made to one or more of these senior-queued Interconnection Requests.

3.2 Contingent Facilities and Planned System Improvements

Contingent Facilities

Contingent Facilities are defined in Section 1 of IPC's LGIP as those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

The following table details the identified Contingent Facilities associated with Interconnection Request #590 that are required to be completed prior to the interconnection of this Project, as identified in the System Impact Study Report dated March 21, 2023.

Table 6
Identified Contingent Facility Network Upgrades.

Contingent Facility	Estimated In-Service[3]	Cost Estimate[4]
Construct a new [redacted] station for #590 between the #667 POI and [redacted] Substation	TBD	$6,108,205

[3] As of the date of this report, #590 is in Suspension.
[4] These cost estimates are in 2023 dollars. If this Contingent Facility Network Upgrade is requested to be advanced, the cost estimate will be evaluated and updated to current dollars.

Contingent Facility	Estimated In-Service[3]	Cost Estimate[4]
Modify the [redacted] Substation series capacitor of the [redacted] line by bypassing segment 2, and rebuilding segment 1 [redacted]	TBD	$1,000,000
Install a new [redacted] series capacitor at [redacted] on the [redacted] line	TBD	$12,925,245
	Total	**$20,033,450**

Contingent Transmission Provider Planned System Improvements

No contingent IPC planned system improvements were identified.

3.3 Affected Systems

Affected System is defined in Section 1 of IPC's LGIP as an electric system other than IPC's Transmission System that may be affected by the proposed interconnection.

IPC has not identified an Affected System for this Project. If an Affected System is later identified, IPC will notify both Interconnection Customer and Affected System, and an Affected System study may be required.

4. Estimated Milestones

4.1 Milestones Overview

The milestone dates in this section 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 Commercial Operation Date (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 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. For these and other reasons, IPC does not warrant or guarantee the estimated milestone dates, which are estimates only.

In the event Interconnection Customer is unable to meet the 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 Article 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.

4.2 Estimated Milestones Detail

Interconnection Customer has requested a COD of December 31, 2028. 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 does not align with the requested COD.

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 the specified date(s) may result in the loss of milestone dates and construction schedules set forth below.

Table 7
Estimated Milestones

Estimated Date	Responsible Party	Milestone
March 7, 2024	Interconnection Customer	**Complete** LGIA Execution
March 14, 2024	Interconnection Customer	**Complete** Provide required documentation: • Demonstration of continued Site Control • Certificate of Insurance • Reasonable evidence to show one or more of the development milestones as per LGIP Section 11.3 has been achieved
[redacted]	Interconnection Customer	**LGIA Suspended**
Date no later than 3 years following Suspension	Interconnection Customer	**Unsuspend LGIA**
15 Business Days following LGIA Unsuspension	Interconnection Customer	**Project Re-Initiation** • Provide updated construction funding or arrangements acceptable to IPC made with IPC's Credit Department • Provide Notice to proceed with engineering, design, and construction
10 months following Project Re-Initiation	Interconnection Customer[5]	**Land Procurement** Transmission Provider's Interconnection Facilities Land Transaction Documents executed, including access easements Detailed in Appendix A & B attached
The longer of 24 months following Project Re-Initiation or 12 months following Land Procurement	IPC	Engineering and Design complete
The longer of 24 months following Project Re-Initiation or 12 months following Land Procurement	Interconnection Customer	Easements and permits procured for IPC site; construction will not begin until easements and permits are in place
40 months following Project Re-Initiation[6]	IPC	Long Lead Material procured/received
10 months prior to COD	Interconnection Customer	Provide updated EMT models to complete modeling in accordance with IPC's OATT Attachment O
8 months prior to Commissioning of IPC's Interconnection Facilities	IPC	Network modeling submission Failure to submit by given lead time will result in Project delay

[5] If Interconnection Customer elects to have IPC procure the land for the Transmission Provider Interconnection Facilities, Interconnection Customer should notify IPC as soon as possible to prevent Project delay. Note that additional time may be required for IPC to procure the land.
[6] Construction cannot be complete until long-lead items are received. Long lead items may become the critical path if Land Procurement takes less time than assumed in the Estimated Milestones.

Estimated Date	Responsible Party	Milestone
180 Calendar Days prior to Initial Synchronization	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 Interconnection Customer’s Interconnection Facilities per LGIA Article 5.10.1
90 Calendar Days prior to Initial Synchronization	Interconnection Customer	Provide final specifications for Interconnection Customer’s Interconnection Facilities 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
23 months after Engineering & Design Complete	IPC	Construction of IPC’s Interconnection Facilities and Network Upgrades Complete
2029	IPC	All Transmission Provider planned system improvements complete
TBD	IPC	Identified Contingent Facility Network Upgrades in service (Table 6)
1 month following completion of all previous construction milestones	IPC	Commissioning of IPC’s Interconnection Facilities and Network Upgrades Complete Back feed power is available
Any time after Commissioning Complete **Note**: Switching request must be made a minimum of 5 days prior to In-Service Date	Interconnection Customer	**In-Service Date** Switch at the POI can be closed to obtain back feed power
15 Calendar Days after In-Service Date	Interconnection Customer	**Initial Synchronization Date** Interconnection Customer Trial Operation begins; test energy can be generated only if the IC has arranged for the delivery of such energy
30 Calendar Days prior to COD	Interconnection Customer	Notify IPC of COD
Prior to COD	Interconnection Customer	Pass Generating Facility Functional Testing
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 24.4
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 Facilities per LGIA Article 5.10.3

5. Interconnection Details

5.1 Generating Facility

The Generating Facility is defined in Section 1 of IPC's LGIP as Interconnection Customer's device(s) for the production and/or storage for later injection of electricity identified in the Interconnection Request but shall not include Interconnection Customer's Interconnection Facilities.

Interconnection Customer's system will be constructed as follows:

1. The photovoltaic inverter system will comprise of [redacted] inverters.
2. The BESS inverter system will comprise of [redacted] inverters.
3. 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 specified by IPC at the POIs.

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

Operating Assumptions for Battery Energy Storage System

The BESS component of the Project was studied charging from the grid in an unstressed case and limited local area N-1 contingency analysis. There may be times during the year where system load in the local area will prevent charging of the BESS from the grid at full capacity; for example, a forced outage that would require IPC to curtail charging. Should the Project require non-curtailable grid charging, firm Point-to-Point transmission service from the energy market/source to the BESS would be required.

5.2 Other Facilities Provided by Interconnection Customer

Telecommunications

Interconnection Customer is not responsible for any third-party communication circuits for IPC's Interconnection Facilities. Any additional telecommunication requirements, including OPGW on the gen-tie line, will be the sole responsibility of Interconnection Customer.

Ground Fault Equipment

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

Generator Output Limit Control

Interconnection Customer will install equipment to receive/transmit signals from IPC Load Serving Operations for Generation Output Limit Control (GOLC)—see Section 5.5 of this RFSR. IPC's recommended method of communication for GOLC is via fiber between the Interconnection Facilities and the Project.

Local Service

Interconnection Customer is required to take local service from the local service provider as a retail customer. Interconnection Customer is responsible to arrange for local service to Interconnection Customer's Interconnection Facilities and/or Generating Facility.

If receiving local service from IPC, Interconnection Customer shall 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.

Property

This Project will require a new 230kV POI Station to be constructed to interconnect Interconnection Customer's gen-tie lines and the existing Boise Bench to Midpoint #2 230kV transmission line ([redacted]). It is preferred that Interconnection Customer acquire the approximately [redacted] of new land and then transfer it to IPC in accordance with the land transaction document requirements listed in this section. Interconnection Customer may request that IPC procure the land, in which case, the milestone schedule may be subject to change. Regardless of whether Interconnection Customer or IPC procure the land, Interconnection Customer will be responsible for all expenses related to the land procurement consistent with Article 5.13 of the LGIA. Cost of the land is not included in the estimate provided in this report.

IPC's Interconnection Facilities and associated substation will be owned and maintained by IPC. Interconnection Customer, at its sole cost and expense, will provide IPC documents and services as identified in this section relating to IPC's land rights required for IPC's Interconnection Facilities and associated substation.

Land Transaction Documents

Land Transaction Documents in a form approved by IPC may include, but are not limited to, the following:

- Right of Entry Agreement
- Fee Ownership Parcel conveyance pursuant to a Warranty Deed
- Purchase and Sale Agreement
- Access Easement

- Easements for distribution service lines, major distribution power lines, and transmission power lines and related ancillary facilities as determined necessary by IPC at IPC's sole discretion, to support the Interconnection Facilities and the Project

- Completed Applications with respective fees for Release of Easements and/or Crossing Agreements that may be required for the Project

- Crossing Agreements

- Any other Project-specific documents deemed necessary by IPC

IPC review and approval of the Land Transaction Documents may require six to nine months. Interconnection Customer is advised to provide all required Land Transaction Documents at the earliest possible time. Refer to Appendix B for a complete reference guide to IPC's Corporate Real Estate Fee Acquisition requirements.

Upon IPC approval of all Land Transaction Documents, IPC will provide Interconnection Customer final form documents for signature by the landowner of record. Interconnection Customer shall return the original signed and recorded Land Transaction Documents to IPC. All recording and mailing fees shall be paid by Interconnection Customer. IPC shall provide to Interconnection Customer electronic copies of all fully executed and recorded Land Transaction documents.

Site Work

Interconnection Customer will provide property, property access, and site plan. IPC will perform land clearing and grading for IPC's Interconnection Facilities and associated substation.

Monitoring Information

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

Meteorological Data

To integrate the solar energy into IPC's 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 ten (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
- ***Pyranometer***: Apogee Instruments Model SP-230

Generator Technical Information and 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 LGIA.

5.3 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.

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. Interconnection projects must meet or exceed the low voltage ride-through requirements as set forth in NERC Reliability Standard PRC-024 and PRC-029, when effective.

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 and PRC-029, when effective. Use of momentary cessation is not considered ride through within the No Trip zone curves of PRC-024 or mandatory and continuous operation regions of PRC-029. 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 Interconnection Customer side of the POCO 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 [redacted] switches, and 3) a terminal clearance is issued by IPC's Load Serving Operator.

5.4 Reactive Power

The Project will be required to provide reactive power versus real power capability measured at the high side of the main power transformer that complies with IEEE 2800-2022 *IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems*, or any subsequent standards as they may be updated from time to time.

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 Section 5.5 of this RFSR.

5.5 Generation Interconnection Supervisory Data Requirements

Interconnection Communications

All supervisory data points described in this Section 5.5 of the RFSR are to be communicated between Interconnection Customer and IPC via serial DNP 3.0 protocol. The physical transport will be fiber cables.

Interconnection Customer is responsible for this fiber connection from their PLC or other controls equipment to the POCO.

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 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 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 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 ten (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 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.

Auxiliary Data Points

Additional status points relating to local weather, equipment, and other supervisory information are 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 of the RFSR.

Table 8

Transmission-interconnected solar Generation Interconnection Supervisory Data Table.

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	52A Interconnection Customer Main Breaker (if present)	Open/Closed	Sourced at substation
2	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	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

Analog Inputs to IPC (DNP Obj. 30, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
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						

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						

Table 9
BESS Generation Interconnection Supervisory Data Table.

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	52A Interconnection Customer Main Breaker (if present)	Open/Closed	Sourced at substation
2	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	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	SPARE						
4	SPARE						

Analog Inputs to IPC (DNP Obj. 30, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
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 A

IPC Survey Requirements

- ☐ Is the Grantor's Deed Instrument No. noted in the Exhibit 'A' Legal Description or Exhibit 'B' Survey Map?
- ☐ Are the Section, Township, Range, and County information clearly stated on the Exhibits?
- ☐ Is the Basis of Bearings between found monuments called out and noted on the Exhibits?
- ☐ Are the Point of Commencement, Point of Beginning and or Point of Terminus shown on the Exhibits?
- ☐ Do all lines have a bearing and distance associated with them on the Exhibits?
- ☐ All lines need bounding calls to Grantor's ownership lines, Rights-of-Way, etc. in Exhibit A.
- ☐ Are the Subdivision names, lot & block, and streets labeled on the Exhibit B?
- ☐ Are any existing Utility Easements adjoining this Easement called out and shown on the Exhibits?
- ☐ Is the map scale noted and is there a North arrow shown on the Exhibit B?
- ☐ On a strip easement is the width given and does it call to form a closed figure in the Exhibit A?
- ☐ Does the Parcel description close?
- ☐ Are the reference surveys of record or CP&Fs used to prepare the easement called out and shown on the Exhibits?
- ☐ A Professional Land Surveyor or Engineer in responsible charge must stamp, sign and date the exhibits for submission.
- ☐ A copy of the current Deed of Record for the Grantor is needed for submission.

Appendix B

IPC Parcel Acquisition Requirements for Interconnection Customers

Interconnection Customer Land Requirements for Development of Transmission Provider's Interconnection Facilities—Fee Acquisition

These requirements were developed by Idaho Power Company's (IPC) Corporate Real Estate department. Allow a minimum of six months for land transaction portion of the Project—may be longer depending on Project specifics.

1. **Project Map/Site Plan.** A 90% complete informational map or site plan of the Project Property with locations of all easements to be released, new easements proposed for both Interconnection Customer and IPC, existing IPC lines to be crossed by Interconnection Customer's facilities, Interconnection Customer's lease and easement areas (if any), access roads, and any other features or elements requested to be included by IPC to facilitate review and processing of the Project documents.

2. **Surveyed Legal Descriptions and Maps.** Written legal description and map for each Land Transaction Document, stamped and signed by a licensed surveyor. Each legal description and map are to be submitted to and approved by IPC's surveyor. See IPC survey requirements in Appendix B, attached hereto and made a part hereof.

3. **Right of Entry Agreement**. A Right-of-Entry Agreement will allow IPC to conduct necessary studies and review of the property and substation lands to determine feasibility for development. This document is required to be signed by the underlying property owner as soon as possible and will allow the preliminary stages of Project development to commence pending completion of the transfer of substation lands to IPC.

4. **Purchase and Sale Agreement – Warranty Deed – Access Easement – Power Line Easements**. IPC requires the substation land be provided in a form of fee ownership acceptable to Idaho Power. A Purchase and Sale Agreement provides the terms for the fee ownership transaction. The Purchase and Sale Agreement includes a Warranty Deed for the transfer of the substation land to IPC, a form of Access Easement for access to the substation land, and forms of transmission and distribution easements.

5. **Land Division (if needed)**. Should a division of land be necessary to create a new Fee Ownership Parcel, Interconnection Customer shall submit application to the proper local jurisdiction and complete all requirements to finalize the creation of a new Fee Ownership Parcel in IPC's name. Interconnection Customer shall provide final approval documentation to IPC.

6. **Title Commitment/Insurance**. Title report and American Land Title Association (ALTA) extended owners' *pro forma* policy of title insurance for the value of the Interconnection Facility Fee Ownership Parcel and access easement areas.

Interconnection Customer shall provide proof and information to establish the value of the property to be insured. IPC will review the title policy pro forma and will advise of any necessary title mitigation measures to ensure clear and unencumbered title to the Interconnection Facility Fee Ownership Parcel and access easement areas. Title mitigation measures shall be performed by Interconnection Customer at Interconnection Customer’s sole cost and expense. Title policy to include endorsements as required by IPC at Interconnection Customer’s sole cost and expense. Interconnection Customer to provide an electronic copy of all exceptions to title insurance for IPC review. Interconnection Customer to provide IPC with a final ALTA extended owners’ policy of title insurance.

7. **Survey**. An ALTA survey of the Project property with all existing IPC easement rights and facilities identified. The ALTA survey shall include and identify all proposed land transaction areas. Interconnection Customer shall provide an ALTA survey of the Fee Ownership Parcel to be conveyed to IPC and all Land Transactions.

8. **Legal Descriptions**. Written legal descriptions, stamped and signed by a surveyor licensed in the State of Idaho, are required for the substation parcel, access easement area, and all distribution/transmission line easement parcels. The written legal descriptions will be reviewed by IPC’s surveyor who will advise of any necessary revisions.

9. **Phase I Environmental Analysis**. A Phase I environmental analysis (Phase I EA) of Interconnection Customer’s Project property (whether fee-owned, leased, or on an easement premises) is required for IPC’s review. The Phase I EA shall provide a map indicating the location of IPC’s Interconnection Facilities in relation to any identified areas of concern. Interconnection Customer shall provide IPC with a Phase 1 EA study prepared by an independent environmental site assessment company, in IPC’s name, which recognizes IPC as the purchaser of the substation parcel and User of the Phase I EA report, and which provides warranties to IPC for the substation parcel and access to easement areas. The Phase I EA study will be reviewed by IPC, and IPC will advise if a Phase II EA or other necessary actions are required based on the results of the Phase I EA study.

10. **Public Lands Permits or Authorizations (if needed)**. Should any agency lands, rights-of-way, etc. be affected by the granting of land and easement rights to IPC, Interconnection Customer shall be responsible to any secure necessary agency authorizations or permits in IPC’s name, at Interconnection Customer’s sole cost and expense. Interconnection Customer shall be responsible to ensure all conditions of approval are satisfied, fees are paid, etc.

11. **Land Use Permits or Authorizations**. Interconnection Customer shall be responsible to secure any necessary land use entitlements or authorizations from the local jurisdiction, local agencies, State of Idaho, or Federal or other agencies to allow the development of the substation parcel, access road and ancillary transmission or distribution lines and facilities (e.g., Conditional Use Permit from the city or county). Any such authorizations

shall be secured in IPC's name and for the benefit of IPC. IPC will require Interconnection Customer to satisfy all conditions of approval and requirements for any such entitlement or authorization. A copy of each authorization pertaining to IPC facilities shall be provided to IPC.

12. **Costs**. Any costs pertaining to the above items shall be at Interconnection Customer's sole cost and expense.

13. **Miscellaneous Documents.** Other miscellaneous documents as necessary for the Project, which may include Memorandums of Agreement/Understanding, etc.

Revision History

Date	Author	Revisions
05/02/2025	Laura Nelson	Interconnection Facilities Restudy Report version 1.0 issued.
06/09/2025	Laura Nelson	Added explanation of series compensation work in Sections 2.3 and 2.4. Version 1.1.