GENERATOR INTERCONNECTION

FEASIBILITY STUDY REPORT

for integration of the proposed

19.26 MW [redacted] PROJECT

(GI PROJECT #797)

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

in

TWIN FALLS COUNTY, ID

for

[redacted]

Report v1.0

November 25, 2025

Table of Contents

Introduction

[redacted] has contracted with Idaho Power Company (Transmission Provider) to perform a Generator Interconnection Feasibility Study (FeS) for the integration of the proposed 19.26 MW [redacted] (the Project) at a single Point of Interconnection (POI) at 138 kV at Idaho Power's Milner substation. The Project is located in Twin Falls County, ID at approximately [redacted]. The project is assigned Generation Interconnection (GI) queue number 797 (GI #797).

This report documents the basis for and the results of this FeS for the GI #797 Generation Interconnection Customer. The report describes the study assumptions, the proposed Project, the determination of the Project interconnection requirements, and estimated costs for integration of the Project to the Transmission Provider transmission system. This report satisfies the FeS requirements of Idaho Power's Open Access Transmission Tariff (OATT).

1.0 Study Assumptions

- As a Small Generating Facility, the Project is studied using Energy Resource Interconnection Service (ERIS).
- For ERIS, Interconnection Customer's ability to inject its Generating Facility output beyond the POI will depend on the existing capacity of Transmission Provider's Transmission System at such time as a transmission service request is made that would accommodate such delivery. Transmission Service may require the construction of additional Network Upgrades.
- If Interconnection Customer wishes to interconnect its Small Generating Facility using Network Resource Interconnection Service (NRIS), it must do so under the Large Generator Interconnection Procedures and execute the Standard Large Generator Interconnection Agreement.
- Senior-queued GI requests that were considered in this study are listed in Section 4.0. If any of these requests are withdrawn, the Transmission Provider reserves the right to restudy this request, and the results and conclusions could significantly change.
- Power flow analysis requires WECC base cases to reliably balance under peak load conditions the aggregate of generation in the local area, with the Generating Facility at full output, to the aggregate of the load in the Transmission Provider's Transmission System. However, Idaho Power's Balancing Authority Area has proposed generation in the GI queue that far surpasses projected load. To reliably balance the power flow case, it is necessary to assume some portions of other resources are displaced by this Project's output in order to assess the impact of interconnecting this Project's generation and that some generation is being transferred regionally through the transmission system.
- The Most Severe Single Contingency (MSSC) is the balancing contingency event, due to a single contingency, that results in the greatest loss (measured in MW) of resource output used by the Balancing Authority at the time of the event to meet firm system load and export obligation. An NRIS Interconnection Request greater than the MSSC must mitigate single contingencies that would result in the loss of more than the MSSC. This

includes, but is not limited to, single contingencies in the Interconnection Customer's Interconnection Facilities.

- Idaho Power will not mitigate thermal violations with remedial action schemes (RAS) in the GI process.

- The following Transmission Provider planned system improvements were assumed in service. Should the Project elect to move forward into the System Impact Study phase, any Transmission Provider planned system improvement facilities that are contingent will be identified.

    - 50% series capacitance compensation on the Kinport to Midpoint 345 kV transmission line (2026)
    - Midpoint Substation transformer T502 500:345 kV transformer (2026)
    - Bowmont to Hemingway 230 kV transmission line (2026)
    - Bowmont to Hubbard 230 kV transmission line (2026)
    - Boardman to Hemingway 500 kV transmission line (2027)
    - Mayfield 500kV/230kV substation (2028)
    - Hemingway to Mayfield 500 kV transmission line (2028)
    - Mayfield to Midpoint 500kV transmission line (2030)

2.0 Description of Proposed Generating Project

The primary POI for the Project is the 138kV bus at Milner substation, with a maximum injection of 19.26 MW. The Project's requested Commercial Operation Date (COD) is April 1, 2029.

Project Location	[redacted]
Generator Nameplate Rating	[redacted] MVA
Total Output Power Rating	19.26 MW to POI
Main Power Transformer	[redacted]
Rated Power Factor	0.80

Table 1. GI #797 Project Specifications

3.0 Protection and Control

Studies indicate that there is adequate load and short circuit interrupting capability on the Transmission Provider's existing circuit breakers after this Project is interconnected.

For 138kV line protection, the Transmission Provider's System Protection Department utilizes permissive and line differential protection schemes integrated with digital communication infrastructure. Idaho Power will require OPGW in the static wire position for any lead-line interconnection facility or fiber communication between co-located facilities. Interconnection Customer will be responsible for communication infrastructure between Interconnection Customer's 138kV substation and Idaho Power.

The proposed 138/[redacted] transformer specified in the Project should provide an adequate ground return path for transmission line protection/relaying.

Grounding requirements and acceptability criteria are found in Appendix A.

4.0 Description of Power Flow Cases

Idaho Power generation interconnection projects GI #558, GI #633, GI#764, GI#768, GI#769, and GI#770 are senior-queued projects in the affected area of Idaho Power's transmission system. Idaho Power studied GI #797 with all Network Upgrades for the identified senior-queued projects as in-service (potential contingent facilities). Should GI #797 elect to move forward into the System Impact Study phase, the facilities that are contingent will be identified.

Changes to senior-queued projects, including in-service date and withdrawal from the queue, may trigger a restudy associated with GI #797.

The WECC 2026 Light Spring and 2030 Heavy Summer cases serve as the Base Cases for the power flow analysis for this FeS. The Base Cases have been modified to:

- increase power flow across the Transmission System to stress relevant transmission paths,
- include future Idaho Power transmission projects,
- include higher-queued generation Interconnection Requests, their Interconnection Facilities, and their Network Upgrades, and
- include Generating Facilities interconnected to Affected Systems that may have an impact on this Interconnection Request.

The WECC 2030 Heavy Summer base case was modified to represent a summer month with high west-to-east (eastbound) transfers across the Borah West (Path 17) WECC path.

The WECC 2026 Light Spring base case was modified to represent a shoulder month condition with high east-to-west (westbound) transfers across the Borah West (Path 17) WECC path. The WECC 2026 Light Spring base case was also modified to represent a shoulder month with low load and high generation in the area of the Project.

5.0 POI Facilities

Listed below are the required transmission facilities to interconnect the Project at the POI.

Adding a new line terminal to the station requires a yard expansion and significant upgrades to system protection and control. The actual station layout and detailed equipment requirements will be determined in the Facilities Study should Interconnection Customer choose to move to that study phase of the GI process. In Table 2 below, a summary is provided of the facilities and conceptual costs required to interconnect the Project to the Transmission Provider's transmission system.

Item of Work	Estimate
A generation interconnection and protection package at the POI requiring station yard expansion, one (1) new 138kV power circuit breaker and line terminal at the substation, associated air break switches, foundations, protective relays, 3-phase potential transformers (PT), 3-phase current transformers (CT), metering, communications, control, and SCADA equipment.	$3,127,049
Subtotal	**$3,127,049**
Contingency 30% (1)	$938,115
Total unloaded costs	**$4,065,164**
Overheads (2)	$162,607
Total Conceptual-level Cost Estimate (3)	**$4,227,770**
(1) Contingency is added to cover the unforeseen costs in the estimate. These costs can include unidentified design components, material cost increases, labor estimate shortfalls, etc. (2) Overhead costs cover the indirect costs associated with the Project and are subject to change. (3) This cost estimate includes direct equipment, material, labor, and overheads as shown.	

Table 2. Estimated GI #797 Project's POI Costs

Note the following regarding Table 2:

- These estimates do not include the cost of Interconnection Customer's equipment/ facilities or required communication circuits for SCADA, Interconnection Customer's Protection, or metering.
- These costs assume the use of Idaho Power-contracted resources.
- These are non-binding conceptual level cost estimates that will be further refined upon the request and completion of the Facilities Study; final charges to Interconnection Customer will be based on the actual construction costs incurred.
- These costs include both Interconnection Facilities (direct assigned) and Network Resources (reimbursable). These costs will be explicitly broken out in the Facilities Study.

The schedule for designing, procuring, and constructing facilities will be developed and optimized during the Facilities Study should Interconnection Customer choose to move to that study phase of the GI process.

6.0 System Upgrades

Power flow solution was achieved for all the contingencies simulated. Power flow analyses revealed no violations requiring Network Upgrades.

7.0 Description of Operating Requirements

The Project will be required to control voltage in accordance with a voltage schedule as provided by Idaho Power Load Serving Operations. The Project will be required to manage the real power output of their generation project at the POI. The Project will be required to operate at a minimum of 0.95 leading/lagging measured at the POI to maintain voltage within limits at the POI.

The Project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-1992 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*.

It may be beneficial for the Interconnection Customer, for their own modeling compliance requirements, to install PMU devices at their facilities to monitor their generation sources.

8.0 Conclusion

Interconnection requirements detailed in Section 5.0 with an estimated cost of $4,227,770 are required to interconnect the Project at the POI. No additional upgrades were identified.

APPENDIX A

A-1.0 Method of Study

The power flow cases for the Feasibility Study are built using Western Electricity Coordinating Council (WECC) power flow cases as a base case in Power World Simulator. The base cases are then modified to include any Idaho Power planned projects expected to be in service if not already included in the case and the senior-queued generation interconnection projects in Section 4.0 and their respective network upgrades and POI facilities. The generation project being studied is then added to the cases with the model provided by [redacted] at the requested POI. The base cases are then rebalanced such that the applicable WECC transmission paths are at their WECC path rating with reasonable pre-contingency energy transfers utilizing the Idaho Power transmission system. The power flow model is then analyzed using P1 and P2 category contingencies contained in Table 1 of NERC standard TPL-001. WECC and Idaho Power reliability criteria are applied to the results of the contingency analysis and any violations are mitigated with Network Upgrades or contingent facilities, (see also Section 6.0).

A-2.0 Acceptability Criteria

The following acceptability criteria were used in the power flow analysis to determine under which system configuration modifications may be required:

> The continuous rating of equipment is assumed to be the normal thermal rating of the equipment. This rating will be as determined by the manufacturer of the equipment or as determined by Idaho Power. Less than or equal to 100% of continuous rating is acceptable.
>
> Idaho Power's Voltage Operating Guidelines were used to determine voltage requirements on the system. These state, in part, that distribution voltages under normal operating conditions are to be maintained within plus or minus 5% (0.05 per unit) of nominal everywhere on the feeder. Therefore, voltages greater than or equal to 0.95 p.u. voltage and less than or equal to 1.05 p.u. voltage are acceptable.
>
> Voltage flicker during starting or stopping the generator is limited to 5% as measured at the point of interconnection, per Idaho Power's T&D Advisory Information Manual.
>
> Idaho Power's Reliability Criteria for System Planning was used to determine proper transmission system operation.
>
> All customer generation must meet IEEE 519 and ANSI C84.1 Standards.
>
> All other applicable national and Idaho Power standards and prudent utility practices were used to determine the acceptability of the configurations considered.
>
> The stable operation of the system requires an adequate supply of volt-amperes reactive (VAr or VArs) to maintain a stable voltage profile under both steady-state and dynamic system conditions. An inadequate supply of VArs will result in voltage decay or even collapse under the worst conditions.

Equipment/line/path ratings used will be those that are in use at the time of the study or that are represented by IPC upgrade projects that are either currently under construction or whose budgets have been approved for construction in the near future. All other potential future ratings are outside the scope of this study. Future transmission changes may, however, affect current facility ratings used in the study.

A-3.0 Grounding Guidance

IPC requires interconnected transformers on the distribution system to limit their ground fault current to 20 amps at the Point of Interconnection.

A-4.0 Electrical System Protection Guidance

IPC requires electrical system protection per Facility Connection Requirements found on the Idaho Power website,

https://docs.idahopower.com/pdfs/BusinessToBusiness/FacConnReq.pdf

A-5.0 WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements

IPC requires frequency operational limits to adhere to WECC Under-frequency and Over-frequency Limits per the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements available upon request.

A-6.0 Grid Enhancing Technology

The following technologies are considered when addressing voltage instability: static synchronous compensator, static VAR compensator, and synchronous condensers. Voltage instability was not found in the study.

The Transmission System interconnects all major generating stations and main load centers in the system. For reliable service, a bulk electric system must remain intact and be capable of withstanding a wide variety of disturbances. The integrated electric system is designed and operated such that the more probable contingencies can be endured with no loss of load and the more adverse contingencies do not result in uncontrolled and widespread power outages. The need to modify the electric configuration of the system or apply transmission switching was not found in the study.

Voltage source converters are used to connect HVAC and HVDC systems. Idaho Power does not act as a Transmission Provider for HVDC systems.

Advanced conductors have a higher cost when compared to more traditional conductors. However, reconductoring with advanced conductors may be less expensive than building new transmission lines. The need to modify the conductors used in an existing line, or rebuild a line, was not found in the study.

Power flow control devices are considered when a transmission element is overloaded and would benefit from a redistribution of flow. This can be accomplished through series reactors, series capacitors, or an equivalent technology. The need to evaluate power flow control devices was not found in the study.

Raising lattice tower heights to provide more clearance may facilitate reconductoring a transmission line instead of rebuilding the transmission line. Tower lifting was not identified as a potential reconductor solution in this study because there are no existing transmission lines identified as needing to be rebuilt.

Revision History

Date	Revision	Initials	Summary of Changes
11/25/25	1.0	TRS	Initial Report