GENERATOR INTERCONNECTION
FEASIBILITY STUDY REPORT

for integration of the proposed

529.2 MW XXXX XXXX XXXX

(GI PROJECT #714)

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

in

XXXX

for

XXXX

Report v1.1

August 11, 2023

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Introduction

XXXX has contracted with Idaho Power Company ("Transmission Provider") to perform a Generator Interconnection Feasibility Study (FeS) for the integration of the proposed 529.2 MW XXXX XXXX XXXX (the Project) at a single Point of Interconnection (POI) at 230 kV at Idaho Power's Hemingway Substation. The Project is located in XXXX and is assigned Generation Interconnect (GI) queue number 714 (GI #714). The Project has chosen in the Feasibility Study to be studied for Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

This report documents the basis for and the results of this FeS for the GI #714 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 the Idaho Power Tariff.

1.0 Study Assumptions

- For ERIS, the Interconnection Customer's ability to inject its Large Generating Facility output beyond the Point of Interconnection 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.
- 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 outside Transmission Provider's Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.
- Senior-queued generator interconnection 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 If any of these requests are withdrawn, the Transmission Provider reserves the right to restudy this request, and the results and conclusions could significantly change.
- The need for transmission modifications, if any, that may be required to provide NRIS will be evaluated on the basis of 100 percent deliverability of the interconnection request under study.
- 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 interconnection queue that far surpasses projected load. To reliably balance the power flow case, it is necessary to assume some portion 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. Idaho Power's MSSC is 330 MW. An NRIS interconnection request greater than 330 MW must mitigate single contingencies that would result in the loss of more than 330 MW. This includes, but is not limited to, single contingencies in XXXX Interconnection Facilities. The single line diagram sent with the FeS application for GI #714 does not comply with this requirement and will need to be updated prior to the System Impact Study.

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

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

  - Boardman to Hemingway 500 kV transmission line (Q2 2026)
  - 50% series capacitance compensation on the Kinport to Midpoint 345 kV transmission line (2025)
  - Midpoint Substation transformer T502 500:345 kV transformer (2025)
  - Hemingway to Bowmont 230 kV transmission line
  - Bowmont to Hubbard 230 kV transmission line

2.0 Description of Proposed Generating Project

The primary POI for the Project is Hemingway 230 kV with a maximum injection of 529.2 MW. The Project's Commercial Operation Date (COD) is XXXX.

XXXX

Table 1. GI #714 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 230 kV breakers after this Project is interconnected.

For 230 kV line protection, the Transmission Provider's System Protection Department utilizes permissive and line differential protection schemes integrated with digital communication infrastructure. Communication infrastructure between the interconnection's customer's 230 kV collector substation and Idaho Power will be the responsibility of the interconnection customer.

The proposed 230 kV Wye-Grounded/Delta tertiary 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 #530, GI #551, GI #567, GI #590, GI #604, GI #605, GI #619, GI #629, GI #632, GI #634, GI #636, GI #638, GI #639, GI #640, GI #643, GI #646, GI #657, GI #665, GI #666, GI#667, GI #669, GI #690, GI #691, GI #695, GI #696, GI #704, GI #708, GI #709 and GI #710 are senior-queued projects in the affected area of Idaho Power's transmission system. Idaho Power studied GI #714 with all Network Upgrades for the identified senior-queued projects as in-service (potential contingent facilities). Should GI #714 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 #714.

For the NRIS study, two power flow cases were used to study the Transmission Provider's transmission system with heavy east to west power flow and a heavy west to east power flow conditions to determine the required Network Transmission Upgrades.

The WECC 2025 Heavy Summer base case was modified to represent a summer month with high west to east (eastbound) transfers across Midpoint West and Idaho Sierra.

The WECC 2022 Light Winter base case was modified to represent a shoulder month condition with high east to west (westbound) transfers across Idaho Northwest.

5.0 POI Facilities

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

The actual station layout and detailed equipment requirements will be determined in the Facilities Study should the interconnection customer choose to move to that study phase of the interconnection process. In Table 2 and Table 3 below, a summary is provided of the facilities and conceptual costs required to interconnect the GI #714 Project to the Transmission Provider's transmission system for NRIS and ERIS.

NRIS - Item of Work	Estimate
Two terminal generation interconnection and protection package at the POI with 4 new 230 kV power circuit breaker and line terminals at the Substation, associated switches, protective relays, 3-phase potential transformers (PTs) and 3-phase current transformers (CTs), SCADA and remote connectivity. Substation expansion.	$12,690,400
Subtotal	**$12,690,400**
Contingency 30% (1)	$3,807,120
Total unloaded costs	**$16,497,520**

NRIS - Item of Work	Estimate
Overheads (2)	$1,154,826
Total Conceptual-level Cost Estimate (3)	**$17,652,346**
(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 #714 Project's NRIS POI Costs

ERIS - Item of Work	Estimate
One terminal generation interconnection and protection package at the POI with 2 new 230 kV power circuit breaker and line terminals at the Substation, associated switches, protective relays, 3-phase potential transformers (PTs) and 3-phase current transformers (CTs), SCADA and remote connectivity. Substation expansion.	$7,748,800
Subtotal	**$7,748,800**
Contingency 30% (1)	$2,324,640
Total unloaded costs	**$10,073,440**
Overheads (2)	$705,141
Total Conceptual-level Cost Estimate (3)	**$10,778,581**
(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 3. Estimated GI #714 Project's ERIS POI Costs

Note the following regarding Table 2 and Table 3:

- These estimates do not include the cost of the customer's equipment/facilities or required communication circuits for SCADA, PMU, Protection, and metering.
- These costs assume the use of Idaho Power 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 the 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 the generation interconnection customer choose to move to that study phase of the interconnection process.

6.0 System Upgrades

Power flow solution was achieved for all the N-1 and credible N-2 outages simulated. Key findings from the power flow analysis are as follows.

Designation	Contingency	Violation
ERIS/NRIS	Present pre-contingency	Thermal overload of XXXX transformer (T501)

Table 4. Contingency Violations

The following are Network Upgrades assigned to GI #714 to mitigate the violations outlined in Table 4.

Item of Work	Estimate
Install second 500/230 kV transformer at XXXX	$33,000,000
Subtotal	**$33,000,000**
Contingency 30% (1)	$9,900,000
Total unloaded costs	**$42,900,000**
Overheads (2)	$3,003,000
Total Conceptual-level Cost Estimate in 2023 dollars (3)	**$45,903,000**
(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 5. Estimated GI #714 Network Upgrade Costs

7.0 Description of Operating Requirements

GI #714 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 .95 leading/lagging measured at the high side of the main power transformer to maintain voltage within limits at the POI over the range of real power output.

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*.

Installation of phasor measurement unit devices at the POI and maintenance costs associated with communication circuits needed to stream PMU data will also be required to be provided to interconnect the Project. The specific costs associated with the IPC requirements for interconnection customers with aggregate facilities larger than 20 MW to provide PMU data to IPC will be identified in the Facilities Study should the generation interconnection customer choose to proceed to that phase of the interconnection process. Also, it may be beneficial for XXXX , for their own modeling compliance requirements, to install additional PMU devices at their facilities to monitor the generations sources separately.

8.0 Conclusion

Interconnection requirements detailed in Section 5.0 totaling $17,652,346 for NRIS and $10,778,581 for ERIS are required to interconnect the Project at the POI. Additional upgrades totaling $45,903,000 are identified in Section 6.0 for both ERIS and NRIS interconnection. A Contingent Facility study will be conducted during the System Impact Study.

An NRIS interconnection request greater than 330 MW must mitigate single contingencies that would result in the loss of more than 330 MW. This includes, but is not limited to, single contingencies in XXXX Interconnection Facilities. The single line diagram sent with the FeS application for GI #714 does not comply with this requirement and will need to be updated prior to the System Impact Study.

ERIS or NRIS does not in any way convey any right to deliver electricity to any specific customer or point of delivery. A Transmission Service Request will be required to study the Transmission System Impacts.

APPENDIX A

A-1.0 Method of Study

The power flow case for the System Impact study is 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 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 XXXX at the requested 529.2 MW 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 listed in Table 3, 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 pu voltage and less than or equal to 1.05 pu 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.

Revision History

Date	Revision	Initials	Summary of Changes
08/11/23	1.0	PTP	Initial Report