Interim Transitional Cluster Study

Cluster Area 5 Study Report

July 19, 2024

Report v1.0

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1. Study Overview

1.1 Introduction

Transitional Cluster Area 5 (CA5) is generally described as the Western Idaho area and includes the following Interconnection Requests: GI 732, and GI 734. Interconnection Requests within CA5 have proposed a total of 340 megawatts (MW) of new generation.

In accordance with Section 7.3 of Transmission Provider's (hereinafter referred to as Idaho Power) Large Generator Interconnection Procedures (LGIP), this Cluster Study evaluated the impact of the proposed generation interconnections on the reliability of Idaho Power's Transmission System. The Cluster Study considered the Base Case as well as all generating facilities (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Cluster Study is commenced:

(i) are directly interconnected to the Transmission System;
(ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request;
(iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and
(iv) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

1.2 Study Assumptions

- Generation Interconnection Requests GI #556, GI #562, GI #629, GI# 632, GI #634, and GI #696 are senior-queued projects in the affected area of Idaho Power's transmission system. Idaho Power studied this Cluster Area with all Network Upgrades for the identified senior-queued projects as in-service. Changes to senior-queued projects, including in-service date and withdrawal from the queue, may trigger a restudy of this Cluster Area, and the results and conclusions could significantly change.

- Generation Interconnection Requests GI #704, GI #708, GI #710, GI #716, GI #718, GI #719, GI #723, GI #724, GI #725, GI #730, GI #731, GI #732, GI #734, and GI #737 are similarly queued projects in Idaho Power's Transitional Cluster Study. Changes to similarly queued projects within the Transitional Cluster Study, including in-service date and withdrawal from the queue, may trigger a restudy of this Cluster Area, and the results and conclusions could significantly change.

- Network Resource Interconnection Service (NRIS) does not convey transmission service.

- 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 Idaho Power'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 portions of other resources are displaced by these

Interconnection Requests. Based on the volume of senior-queued Interconnection Requests and in order to assess the impact of interconnecting this generation, 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 the Interconnection Customer's Interconnection Facilities.

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

- Projects interconnecting at new greenfield stations (Transmission Provider Interconnection Facilities) will require primary and/or secondary local distribution service be constructed to feed the station. The scope and cost of these potential distribution facilities are not contemplated in this study and will be analyzed in the final Transitional Cluster Study, as applicable.

- Telecommunication requirements are not fully contemplated in this study and could require significant upgrades up to and including line rebuilds to accommodate OPGW, for example. Telecommunication requirements identified during the final Transitional Cluster Study could impact the estimated cost of the project included in this report.

- The following Idaho Power planned system improvements were assumed in service. Any facility that has been determined to be contingent will be listed in Section 5 of this report.
    - Boardman to Hemingway 500kV transmission line (Q2 2027)
    - 50% series capacitance compensation on the Kinport to Midpoint 345kV transmission line (Q2 2026)
    - Midpoint Substation T502 500:345kV transformer (Q2 2026)
    - Hemingway to Bowmont 230kV transmission line (Q4 2025)
    - Bowmont to Hubbard 230kV transmission line (Q3 2026)
    - Midpoint to Hemingway #2 500kV transmission line (2028)

1.3 Power Flow Case Description

The WECC 2024 Light Winter and Heavy Summer Operating cases serve as the Base Cases for the power flow and transient stability analysis for this Transitional Cluster Study. 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 identified in Section 1.2 of this report,

- Include senior-queued generation Interconnection Requests, their Interconnection Facilities, and their Network Upgrades in accordance with Section 7.3 of Idaho Power's LGIP, and

- Generating Facilities interconnected to Affected Systems that may have an impact on the Interconnection Requests in this Cluster Area.

The WECC 2024 Heavy Summer Operating base case was modified to represent a summer month with high west-to-east (eastbound) transfers across the Idaho to Northwest (Path 14) WECC path.

The WECC 2024 Light Winter Operating base case was modified to represent a shoulder month condition with high east-to-west (westbound) transfers across the Idaho to Northwest (Path 14) WECC path.

2. Cluster Area

Idaho Power performed the Transitional Cluster Study based on geographically and/or electrically relevant areas on Idaho Power's Transmission System known as Cluster Areas. Idaho Power has determined that the Interconnection Requests described below are in a geographically and/or electrically relevant area on Idaho Power's Transmission System, and thus were assigned Cluster Area 5 in this Cluster Study.

Cluster Area 5 is generally described as Idaho Power's Transmission System in Western Idaho. This Cluster Area consists of the Interconnection Requests described below.

2.1 GI #732 Description

Interconnection Customer has proposed to interconnect 100 MW of hybrid solar and battery storage generation at the junction point of Idaho Power's Brownlee–Quartz–North Powder 230kV transmission line located in Baker County, Oregon. The requested Commercial Operation Date (COD) is December 15, 2027.

Interconnection Customer will NOT operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Interconnection Request will be studied for NRIS.

2.2 GI #734 Description

Interconnection Customer has proposed to interconnect 240 MW of hybrid wind, solar, and battery storage generation to Idaho Power's North Powder 230kV substation located in Baker County, Oregon. The requested COD is December 15, 2027.

Interconnection Customer will NOT operate this generator as a Qualified Facility as defined by PURPA.

The Interconnection Request will be studied for NRIS.

3. NRIS Requirements

3.1 Transmission Provider's Interconnection Facilities

Transmission Provider's Interconnection Facilities (hereinafter referred to as Idaho Power's Interconnection Facilities) are defined in Section 1 of Idaho Power's LGIP as all facilities and equipment owned, controlled, or operated by Idaho Power from the Point of Change of Ownership to the POI, including any modifications, additions or upgrades to such facilities or equipment. In accordance with Section 4.2.1 of Idaho Power's LGIP, costs for Idaho Power's Interconnection Facilities are directly assigned to Interconnection Customer.

Listed below are Idaho Power's Interconnection Facilities required to interconnect the generation Interconnection Requests at their respective requested POIs.

3.1.1 GI #732 Interconnection Facilities

- One (1) 230kV disconnect switch
- Meter, dead-end structure, 3-phase potential transformers (PTs), 3-phase current transformers (CTs), foundations, and cabling

3.1.2 GI #734 Interconnection Facilities

- One (1) 230kV disconnect switch
- Meter, dead-end structure, 3-phase PTs, 3-phase CTs, foundations, and cabling

3.2 Substation Network Upgrades

Substation Network Upgrades are defined in Section 1 of Idaho Power's LGIP as Network Upgrades that are required at the substation located at the POI; this includes all switching stations. In accordance with Section 4.2.1(a) of Idaho Power's LGIP, costs for Substation Network Upgrades are allocated per capita to each Generating Facility interconnecting at the same substation.

Listed below are the required Substation Network Upgrades required to interconnect the Projects at their respective POIs.

3.2.1 GI #732 Substation Network Upgrades

New 3-position 230kV Ring Bus Substation

Build a new three-position 230kV ring bus substation adjacent to the junction point of Idaho Power's Brownlee–Quartz–North Powder 230kV transmission line. Install three 230kV circuit breakers, necessary 230kV air break switches, foundations, associated relaying/ control/ communications equipment in a control building, bus, grounding, conduit, and conductor for such equipment.

[redacted]

Figure 1 GI #732 Substation Network Upgrades.

3.2.2 GI #734 Substation Network Upgrades

Add fourth position to North Powder Substation 230kV Ring Bus

At Idaho Power's 230kV North Powder Substation, add one 230kV circuit breaker, necessary 230kV air break switches, foundations, associated relaying/control/communications equipment in a control building, bus, grounding, conduit, and conductor for such equipment.

[redacted]

Figure 2 GI #734 Substation Network Upgrades.

3.3 NRIS System Network Upgrades

System Network Upgrades are defined in Section 1 of Idaho Power's LGIP as Network Upgrade that are required beyond the substation located at the POI. In accordance with Section 4.2.1(b) of Idaho Power's LGIP, costs for each specific System Network Upgrades are allocated based on proportional impact of each individual Generating Facility in the Cluster Study.

Listed below are the required System Network Upgrades required for NRIS.

- **Rebuild [redacted] 230kV Line**
  Removal of existing line conductor and structures. Build new 20.6-mile 230kV line with [redacted] and steel poles with OPGW. Replace metering CTs at [redacted] terminal so they do not limit the line rating.
- **Upgrade [redacted] 230kV Line**
  Replace short section of existing conductor between [redacted] and [redacted] 230kV line with [redacted].

Table 1 NRIS System Network Upgrades

Facility Description	Outage	Cost Allocation	Cost Estimate
Rebuild 230kV [redacted]	[redacted] [redacted]	GI732 – 23.3% GI734 – 76.7%	$63,963,000
Upgrade 230kV [redacted]	[redacted] [redacted]	GI732 – 32.9% GI734 – 67.1%	$465,750

3.4 Battery Charging

The energy storage system (ESS) component of each project is 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 ESS from the grid at full capacity; for example, a forced outage that would require Idaho Power to curtail grid charging.

Should the Project require non-curtailable grid charging, a firm Point-to-Point transmission service from the energy market/source to the battery would be required.

If Interconnection Customer does not intend to charge the ESS portion of the project from the grid, Interconnection Customer must notify Idaho Power of this election in writing prior to the closure of thirty (30) Calendar Day comment period on the interim Transitional Cluster Study Report, if not previously requested, and the results of the charging study will not be included in the scope of the final Transitional Cluster Study. Interconnection Customer will be required to demonstrate operating procedures and control measures that prevent the ESS from grid charging. Additionally, Idaho Power shall enable an additional relay setting at the POI to trip the Project if grid-charging is detected.

No additional upgrades are required to support charging the ESS from the grid for any Projects.

3.5 NRIS Cost Estimates

GI #732	
Interconnection Facilities	$989,171
Substation Network Upgrades	$8,997,584
System Network Upgrades	$15,062,829
	Total NRIS: $25,049,584

GI #734	
Interconnection Facilities	$989,171
Substation Network Upgrades	$5,096,547
System Network Upgrades	$49,365,921
	Total NRIS: $55,451,639

3.6 Estimated Time to Construct

Based on the identified scope of work for this Cluster Area, Idaho Power's non-binding, good-faith estimate of time to construct is a minimum of 4–5 years from LGIA execution, funding, and notice to proceed (Project Initiation). A detailed and refined timeline will be provided for each project in the final Transitional Cluster Study Report.

4. Contingent Facilities and Affected Systems

Contingent Facilities are defined in Section 1 of Idaho Power'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.

Table 2 Contingent Facilities

Service	Assigned To	Facility Description	Outage	Planned ISD
NRIS	GI562	Reconductor 69kV [redacted]	[redacted]	2027
NRIS	Idaho Power	Build new 230kV Bowmont–Hemingway #2	[redacted]	Q4 2025
NRIS	Idaho Power	Install Midpoint T502 500/345kV transformer	[redacted]	Q2 2026
NRIS	Idaho Power	50% series compensation 345kV Midpoint–Kinport	[redacted]	Q2 2026
NRIS	Idaho Power	Build new 230kV Bowmont–Hubbard	[redacted]	Q3 2026
NRIS	Idaho Power	Build new 500kV B2H line	[redacted]	Q2 2027
NRIS	Idaho Power	Move portion of Weiser 69kV load to 138kV	[redacted]	2029

Bonneville Power Administration has been identified as an Affected System and may conduct their own study which may have an impact on the Interconnection Customer's cost and timing to interconnect the project to Idaho Power's Transmission System.

5. Transient Stability Analysis

The WECC 2024 Light Winter and Heavy Summer operating case were used with the PowerWorld Simulator version 23 Transient Stability analysis tool to perform the transient stability analysis.

The results showed no transient stability violations. Per NERC Standards, the Generator Owner is responsible to ensure the modeling data utilized accurately reflects inverter operations and provide updates to Idaho Power if testing or real-time observations indicate a need.

6. Voltage Stability Analysis

A Voltage Stability analysis was performed using the WECC 2024 Heavy Summer case with Idaho to Northwest west-to-east flows at 105% of the path rating and the WECC 2024 Light Winter case with Idaho to Northwest east-to-west flows at 105% of the path rating. All contingencies solved successfully; there were no voltage stability issues found due to the Projects.

The Projects will be required to control voltage in accordance with a voltage schedule as provided by Idaho Power's Load Serving Operations. Interconnection Customers will be required to manage the real power output of their Generating Facilities at the POI.

7. Protection and Control

7.1 GI #732 Protection and Control

For 230kV line protection, Idaho Power'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 gen-tie lines and fiber communication between co-located facilities. Interconnection Customer is responsible to provide communication infrastructure between Interconnection's Customer's 230kV collector substation and Idaho Power.

Studies indicate that there is adequate load and short circuit interrupting capability on the Transmission Provider's existing 230kV breakers after this Project is interconnected.

The proposed 230kV Wye-Grounded/Wye-Grounded with a Delta tertiary transformer specified in the Interconnection Request should provide an adequate ground return path for transmission line protection/relaying.

7.2 GI #734 Protection and Control

For 230kV line protection, Idaho Power'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 gen-tie lines and fiber communication between co-located facilities. Interconnection Customer is responsible to provide communication infrastructure between Interconnection's Customer's 230kV collector substation and Idaho Power.

Studies indicate that there is adequate load and short circuit interrupting capability on the Transmission Provider's existing 230kV breakers after this Project is interconnected.

The proposed 230kV Wye-Grounded/Wye-Grounded with a Delta tertiary transformers specified in the Project should provide an adequate ground return path for transmission line protection/relaying.

8. Description of Operating Requirements

Generation Interconnection projects will be required to control voltage in accordance with a voltage schedule as provided by Idaho Power's Load Serving Operations. Interconnection Customers will be required to manage the real power output of their Generating Facilities at the POI. Projects 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.

Projects are 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.

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 Projects. The specific costs associated with the Idaho Power requirements for Interconnection Customers with aggregate facilities larger than 20 MW to provide PMU data to Idaho Power will be identified in the final Transitional Cluster Study should Interconnection Customer choose to proceed to that phase of the interconnection process. Also, it may be beneficial for Interconnection Customers, for their own modeling compliance requirements, to install additional PMU devices at their facilities to monitor the generations sources separately.

9. Total Cost Summary

The cost estimates below are allocated in accordance with Section 4.2.1 of Idaho Power's LGIP.

GI #732	
Total NRIS	$25,049,584
GI #734	
Total NRIS	$55,451,639

NRIS does not convey transmission service and does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Large Generating Facility to any particular load on Transmission Provider's Transmission System without incurring congestion costs. To obtain transmission service for Cluster Area 5 projects, it is anticipated significant transmission upgrades will be needed above and beyond the NRIS cost estimates listed here.

Appendices

A-1 Method of Study

The power flow case for the Cluster 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 Requests identified in Section 1.2 and their respective Network Upgrades and Interconnection Facilities. The Interconnection Requests being studied are then added to the cases with the model provided by the Interconnection Customers at the requested MW injection at the agreed-upon 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 (Idaho Power) Transmission System. The power flow model is then analyzed using P1, P2, and P7 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.

A-2 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 (P-0) 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 while starting or stopping the generator is limited to 5% as measured at the POI, 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, or Path ratings used will be those that are in use at the time of the study or that are represented by Idaho Power 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 Grounding Guidance

Idaho Power requires interconnected transformers on the distribution system to limit their ground fault current to 20 amps at the POI.

A-4 Electrical System Protection Guidance

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

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

A-5 WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements

Idaho Power 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, which are available upon request.

A-6 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 found in the study. Rather than designing the GI#732 230kV ring bus substation as a 4-position ring splitting the Brownlee-Quartz-North Powder 230kV line into three separate two-terminal lines, it was found that reconfiguring the substation to a three-position ring with the Brownlee-GI732-Quartz 230kV line operated as a single zone of protection would mitigate violations 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 found in the study. The use of advanced conductors was assessed in this study. Existing structures are wood poles. Due to fire risk and age of existing wood pole transmission lines, advanced conductors are not an option. An advanced conductor solution is not more cost effective than new transmission lines.

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. Power flow control devices were evaluated in this study. They did not mitigate violations, rather they pushed violations to other locations. Therefore, power flow control devices were not identified as upgrades in this 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.

Revision History

Date	Author	Revisions
07/19/2024	TRS	Cluster Study Report version 1.0 issued.