

Cluster 1

Cluster Area 3 Study Report

November 14, 2025

Report v1.0

OFFICIAL USE ONLY – DO NOT DUPLICATE, DISTRIBUTE, PUBLISH OR SHARE

This report contains Idaho Power Company Critical Energy Infrastructure Information. Distribution of this report must be limited to parties that have entered into a non-disclosure agreement with Idaho Power Company and have a need to know.

Table of Contents

1. Study Overview	2
1.1 Introduction	2
1.2 Study Assumptions.....	2
1.3 Power Flow Case Description.....	4
2. Cluster Area.....	4
2.1 GI #781 Description.....	4
3. Interconnection Facilities and Upgrades	5
3.1 Transmission Provider’s Interconnection Facilities	5
3.1.1 GI #781 Interconnection Facilities	5
3.2 Substation Network Upgrades	5
3.2.1 GI #781 Substation Network Upgrades	5
3.3 System Network Upgrades	6
3.4 Battery Charging	6
3.5 Cost Estimates.....	7
3.6 Estimated Time to Construct	7
4. Contingent Facilities and Affected Systems.....	7
5. Transient Stability Analysis	8
6. Voltage Stability Analysis	8
7. Protection and Control	8
7.1 GI #781 Protection and Control	8
8. Description of Operating Requirements.....	9
9. Total Cost Summary.....	9
Appendices.....	10
A-1 Method of Study.....	10
A-2 Acceptability Criteria	10
A-3 Grounding Guidance.....	11
A-4 Electrical System Protection Guidance	11
A-5 WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements.....	11
A-6 Grid Enhancing Technology.....	11
Revision History	13

1. Study Overview

1.1 Introduction

Cluster Area 3 (CA3) is generally described as the Magic Valley area and includes the following Interconnection Requests: GI #781. Interconnection Requests within CA3 have proposed a total of 90 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 1 Study (Cluster Study) evaluated the impact of the proposed generation interconnections (GI) 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 Generating Facilities—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 a Large Generator Interconnection Agreement (LGIA) or requested that an unexecuted LGIA be filed with FERC.

1.2 Study Assumptions

- Generation Interconnection Requests GI #551, GI #558, GI #588, GI #590, GI #604, GI #605, GI #614/616, GI #624, GI #625, GI #630, GI #633, GI #635, GI #636, GI #656, GI #659, GI #665, GI #667, GI #669, GI #704, GI #708, GI #710, GI #716, #718, and #719 are higher-queued Interconnection Requests in the affected area of Idaho Power's Transmission System. Idaho Power studied this Cluster Area with all Network Upgrades for the identified higher-queued Interconnection Requests as in-service. Changes to higher-queued Interconnection Requests, including in-service date and withdrawal from Idaho Power's GI queue, may trigger a restudy of this Cluster Area, and the results and conclusions could significantly change.
- Generation Interconnection Requests GI #758, GI #759, GI #760, GI #761, GI #762, GI #763, GI #764, GI #765, GI #767, GI #768, GI #769, GI #770, GI #771, GI #772, GI #773, GI #774, GI #775, GI #776, GI #777, GI #778, GI #779, GI #781, GI #782, GI #785, GI #786, GI #787, GI #788, GI #789, GI #790, GI #791, GI #792, and GI #793 are equally queued Interconnection Requests in Idaho Power's Cluster Study. Changes to equally queued Interconnection Requests within the 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.

- Neither Network Resource Interconnection Service (NRIS) nor Energy Resource Interconnection Service (ERIS) 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 Facilities 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 GI queue that far surpasses projected load. Based on the volume of proposed generation in the GI queue generation is being transferred regionally through the Transmission System and some resources are being displaced by the current Interconnection Requests under study.
- 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 or voltage violations with remedial action schemes (RAS) in the GI process.
- Telecommunication requirements are not fully contemplated in this study and could require significant upgrades, up to and including line rebuilds to accommodate optical ground wire (OPGW), for example. Telecommunication requirements identified during the Interconnection Facilities 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.
 - 50% series capacitance compensation on the Kinport to Midpoint 345kV transmission line (2026)
 - Midpoint Substation T502 500:345kV transformer (2026)
 - Bowmont to Hemingway #2 230kV transmission line (2026)
 - Bowmont to Hubbard 230kV transmission line (2026)
 - Boardman to Hemingway (B2H) 500kV transmission line (2027)
 - Hemingway to Mayfield 500kV transmission line (2028)
 - Southwest Intertie Project – North (SWIP-N) 500kV transmission line (2029)
 - Mayfield to Midpoint 500kV transmission line (2030)

1.3 Power Flow Case Description

The WECC 2026 Light Spring and 2030 Heavy Summer cases serve as the Base Cases for the power flow and transient stability analysis for this 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,
- include higher-queued generation Interconnection Requests, their Interconnection Facilities, and their Network Upgrades in accordance with Section 7.3 of Idaho Power's LGIP, and
- include Generating Facilities interconnected to Affected Systems that may have an impact on the Interconnection Requests in this Cluster Area.

The WECC 2030 Heavy Summer base case was modified to represent a summer month with high west-to-east (eastbound) transfers across the Midpoint West internal 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 Midpoint West internal path. The WECC 2026 Light Spring base was also modified to represent a non-stressed light load scenario with high generation in CA3.

2. Cluster Area

Idaho Power performed the 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 CA3 in this Cluster Study.

CA3 is generally described as Idaho Power's Transmission System in the Magic Valley area. This Cluster Area consists of the Interconnection Requests described below.

2.1 GI #781 Description

Interconnection Customer has proposed to interconnect 90 MW of hybrid solar and battery storage generation to Idaho Power's Blue Gulch 138kV substation located in Twin Falls County, Idaho. The requested Commercial Operation Date (COD) for GI #781 is October 1, 2030.

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.

3. Interconnection Facilities and Upgrades

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 (POCO) 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 Request at its requested POI.

3.1.1 GI #781 Interconnection Facilities

- One (1) 138kV disconnect switch
- Meter, dead-end structure, 3-phase potential transformers (PTs), 3-phase current transformers (CTs), foundations, and cabling
- The last span of the Project's gen-tie line, including insulators, conductor, and associated hardware

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 Substation Network Upgrades required to interconnect the Project at its requested POI.

3.2.1 GI #781 Substation Network Upgrades

[redacted]

Figure 1 GI #781 Point of Interconnection

- **New Terminal at Blue Gulch Substation**
New generator interconnection at the Blue Gulch 138kV substation with one (1) 138kV line bay and one (1) 138kV power circuit breaker, one (1) 138kV disconnect switch, generator interconnection protective relays, line protective relays, 3-phase PTs, two (2) 1-phase wave traps, two (2) one-phase power line carrier tuners, and power line carrier communications equipment.

3.3 System Network Upgrades

System Network Upgrades are defined in Section 1 of Idaho Power's LGIP as Network Upgrades 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.

- **Rebuild [REDACTED] 138kV Line**

Rebuild the [REDACTED] 138kV line (10.3 mi) with [REDACTED] conductor and steel poles with OPGW, and replace the [REDACTED] air-break switch with a [REDACTED] switch.

- **Rebuild [REDACTED] 138kV Line**

Rebuild the [REDACTED] 138kV line (0.8 mi) with [REDACTED] conductor and steel poles with OPGW, and replace the [REDACTED] air-break switch with a [REDACTED] switch.

- **New Second [REDACTED] 230/138kV Transformer**

Install a second 230/138kV transformer at [REDACTED] substation. Add one (1) 230kV power circuit breaker, one (1) 138kV power circuit breaker, and associated disconnect switches. Add a connection from the line side of the new 138kV breaker to the [REDACTED] 138kV line. Add new transformer protective relays and replace existing [REDACTED] 138kV line protective relays.

- **Rebuild [REDACTED] 138kV Line**

Rebuild the [REDACTED] 138kV line (0.1 mi) with [REDACTED] conductor and steel poles with OPGW. Replace [REDACTED] bus with [REDACTED] bus.

Table 1 NRIS System Network Upgrades

Facility Description	Outage	Cost Allocation		Cost Estimate ¹
Rebuild [REDACTED] 138kV Line	[REDACTED]	GI781	100%	\$21,361,600
Rebuild [REDACTED] 138kV Line	[REDACTED]	GI781	100%	\$1,690,000
New Second [REDACTED] 230/138kV Transformer	[REDACTED]	GI781	100%	\$8,755,056
Rebuild [REDACTED] 138kV Line	[REDACTED]	GI781	100%	\$743,600

3.4 Battery Charging

The energy storage system (ESS) component of each Interconnection Request was studied charging from the grid in an unstressed case and limited local area N-1 contingency analysis.

¹ The cost estimates include a 30% contingency and current overhead rates, which are subject to change.

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 Generating Facility require non-curtable grid charging, firm Point-to-Point transmission service from the energy market/source to the ESS 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 the thirty (30) Calendar Day comment period on the Cluster Study Report, if not previously requested, and the results of the charging study will not be included in the scope of the Interconnection Facilities 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 a relay setting at the POI to trip the ESS if grid-charging is detected.

No additional upgrades are required to support charging the ESS from the grid for any of the CA3 Interconnection Requests.

3.5 Cost Estimates

The below cost estimates include a 30% contingency and current overhead rates, which are subject to change.

GI #781

Interconnection Facilities	\$750,743
Substation Network Upgrades	\$3,751,347
System Network Upgrades	\$32,550,256
Total:	\$37,052,346

3.6 Estimated Time to Construct

Based on the identified scope of work for this CA3, 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 Interconnection Request in the Interconnection Facilities 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	Transitional Cluster Area 3	Rebuild [REDACTED] 138kV line	[REDACTED]	2028

IPC has not identified an Affected System for CA3. If an Affected System is later identified, IPC will notify both Interconnection Customer and Affected System, and an Affected System study may be required.

5. Transient Stability Analysis

The WECC 2026 Light Spring case and PowerWorld Simulator version 24 Transient Stability analysis tool were used 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 power plant operations and to 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 2030 Heavy Summer case with Midpoint West West-to-East flows at 105% of its path ratings and the WECC 2026 Light Spring case with Midpoint West East-to-West flows at 105% of its path ratings. All contingencies solved successfully; there were no voltage stability issues found for the Project.

The Generating Facilities 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 #781 Protection and Control

For 138kV 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 138kV collector substation and Idaho Power.

Studies indicate that there is adequate load and short circuit interrupting capability on the Transmission Provider's existing 138kV breakers after this Project is interconnected.

The proposed 138kV Wye-Grounded/Wye-Grounded with a Delta tertiary transformer specified in the Project should provide an adequate ground return path for transmission line protection/relaying.

8. Description of Operating Requirements

Generating Facilities 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 Standard 2800 *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.

Projects are required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 2800 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 Generating Facilities. 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 Interconnection Facilities Study should Interconnection Customer choose to proceed to that phase of the GI 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 generation sources separately.

9. Total Cost Summary

The cost estimates below are allocated in accordance with Section 4.2.1 of Idaho Power's LGIP. The total ERIS and NRIS cost estimates include the costs associated with Idaho Power's Interconnection Facilities, Substation Network Upgrades, and System Network Upgrades required for Energy Resource Interconnection Service or Network Resource Interconnection Service, including those facilities identified as necessary for grid-charging any ESS components.

GI #781

Total Cost	\$37,052,346
-------------------	--------------

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 2800 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 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 found in the study. The use of advanced conductors would mitigate violations identified 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.

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 but would be

similar in cost or more expensive than the identified solution, are less effective at mitigating performance issues during various operating scenarios, and were not evaluated further in this study.

Raising lattice tower heights to provide more clearance may facilitate reconductoring a transmission line instead of rebuilding the transmission line. Existing structures are wood poles, so tower lifting is not an option.

Revision History

Date	Author	Revisions
11/14/2025	Trevor Schultz	Cluster 1 Cluster Area 3 Study Report version 1.0 issued.