GENERATOR INTERCONNECTION

FEASIBILITY STUDY REPORT

for integration of the proposed

85 MW [redacted] PROJECT

(GI PROJECT #613)

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

in

ELMORE COUNTY, IDAHO

for

[redacted]

Report v.1

October 7, 2021

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1.0 Introduction

[redacted] has contracted with Idaho Power Company ("Transmission Provider") to perform a Generator Interconnection Feasibility Study for the integration of the proposed 85 MW [redacted] project (the Project). The Project location is in Idaho Power Company's (IPC's) Capital Region in Elmore County, Idaho. The Project latitude and longitude coordinates are approximately [redacted]. The project is Generation Interconnect (GI) queue number 613 (GI #613). The Project has chosen in the Feasibility Study to be studied for Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

The Project has applied to connect to Idaho Power's transmission system for an injection of 85 MW at a single Point of Interconnection (POI) at 138kV. The POI is IPC's [redacted] 138kV transmission line.

IPC projects queue GI #530, GI #551, GI #557, GI #567, GI #570, GI #578, GI #588, GI #590, GI #604, GI #605, GI #611, and GI #612 are senior queued projects in the affected area of IPC's transmission system and their associated Network Upgrades and/or Interconnection Facilities may be contingent facilities. Should GI #613 elect to move forward into the System Impact Study phase the facilities that are contingent will be identified.

This report documents the basis for and the results of this Feasibility Study for the GI #613 Generation Interconnection Customer. The report describes 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 feasibility study requirements of the Idaho Power Tariff.

2.0 Summary

The Interconnection Feasibility Study was done and prepared in accordance with the Transmission Provider's Standard Generator Interconnection Procedures to provide a preliminary evaluation of the feasibility of the interconnection of the proposed generating Project to the Idaho Power system. As listed in the Interconnection Feasibility Study agreement, the Interconnection Feasibility Study report provides the following information:

- preliminary identification of any circuit breaker short circuit capability limits exceeded because of the interconnection;
- preliminary identification of any thermal overload or voltage limit violations resulting from the interconnection; and
- preliminary description and non-binding estimated cost of facilities required to interconnect the Large Generating Facility to the IPC System and to address the identified short circuit and power flow issues.

All other proposed Generation projects prior to this Project in the Generator Interconnect queue were considered in this study. A current list of these projects can be found in the Generation Interconnection folder located on the Idaho Power Oasis web site at the link provided here: **http://www.oatioasis.com/ipco/index.html.**

An Interconnection System Impact Study (SIS) is required to determine if any additional Interconnection Facilities or Network Upgrades are required to mitigate thermal, voltage, transient stability, and/or reactive margin issues. Energy Resource Interconnection Service and/or Network Resource Interconnection Service in and of themselves do not convey transmission service. In addition to Network Upgrades identified in the Interconnection System Impact Study:

- For Energy Resource Interconnection Service, 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. The provision of firm Point-to-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.
- For Network Resource Interconnection Service, 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 into 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.

3.0 Feasibility Cost Estimate

The total "Energy Resource Interconnection Service" generation interconnection preliminary cost estimate to interconnect the Project to the primary study POI is as follows:

- Energy Resource Interconnection Service at proposed 138kV POI - **$11,794,068**

See Section 6.5 Energy Resource Interconnection Service Cost Estimate for the required facilities and cost breakdowns.

The total "Network Resource Interconnection Service" generation interconnection preliminary cost estimate to interconnect the [redacted] project is as follows:

- Network Resource Interconnection Service - **$28,798,942**
    - This does not include costs for any potential contingent facilities from senior queued GI #530, GI #551, GI #557, GI #567, GI #570, GI #578, GI #588, GI #590, GI #604, GI #605, GI #611, and GI #612 projects.

See Section 7.3 Network Resource Interconnection Service Cost Estimate for the required facilities and cost breakdowns. The cost estimate includes a 20% contingency and 7.25% overhead. These are cost estimates only and final charges to the customer will be based on the actual construction costs incurred. It should be noted that the preliminary cost estimates do not include the cost of the customer's owned equipment.

The schedule for designing, procuring, and constructing facilities will be developed and optimized during the Facility Study should the generation interconnection customer choose to move to that study phase of the interconnection process.

4.0 Potential Contingent Facilities

IPC projects queue GI #530, GI #551, GI #557, GI #567, GI #570, GI #578, GI #588, GI #590, GI #604, GI #605, GI #611, and GI #612 are senior queued projects in the affected area of IPC's transmission system. Idaho Power studied GI #613 with all Network Upgrades and Interconnection Facilities identified for GI #530, GI #551, GI #557, GI #567, GI #570, GI #578, GI #588, GI #590, GI #604, GI #605, GI #611, and GI #612 modeled as in service (Potential Contingent Facilities). Changes to senior queued projects including in-service date and withdrawal from the queue, may trigger a restudy associated with GI #613. Should GI #613 elect to move forward into the System Impact Study phase the facilities that are contingent will be identified.

5.0 Description of Proposed Generating Project

Assumptions

The primary point of interconnection for GI #613 is the [redacted] 138kV transmission line. Assumed GI #613 Project's maximum generation is 85 MW from the combined Photovoltaic (PV) and Battery Energy Storage System (BESS). The Project's Commercial Operation Date (COD) is June 1, 2023.

GI #613:

- (1) 138/34.5kV GSU transformer with 63/84/105 MVA capacity
- (32) Sungrow SG3150U inverters and (32) 3150 kVA D/y transformers
- BESS charged via PV output and the transmission system
- All generation in voltage regulation (Reactive capability used to regulate voltage – supply/absorb reactive)

6.0 Energy Resource Interconnection Service (ERIS)

Energy Resource Interconnection Service (ERIS) allows the Interconnection Customer to connect its Generating Facility to Transmission Provider's transmission system and to be eligible to deliver electric output using firm or non-firm transmission capacity on an as available basis.

The GI #613 Project has applied to connect to the Idaho Power transmission system for an injection of 85 MW with a new 138kV interconnection at the [redacted] 138kV transmission line. All generation projects in the area ahead of this Project in the IPC generation queue and their associated transmission system improvements were modeled in a preliminary power flow analysis to evaluate the feasibility of interconnecting GI #613.

6.1 Description of Substation/Transmission Facilities

The proposed interconnection will require two new 138kV breakers to avoid creating a 4-terminal line of [redacted] 138kV.

From the power flow/contingency analysis, the following Network Transmission upgrades were identified for the integration of GI #613 for Energy Resource Interconnection Service (ERIS). A System Impact Study will ultimately be required to determine the specific network upgrades required to integrate the Project.

1. Reconductor [redacted] 138kV line (~[redacted] miles) with [redacted] conductor

The actual station layout and detailed equipment requirements will be determined in the Facility Study should the interconnection customer choose to move to that study phase of the interconnection process.

6.2 Description of Distribution Facilities

No distribution facilities are directly impacted by this Project.

6.3 Short Circuit Study Results

The short circuit/fault duty at approximate GI #613 POI 138kV bus location and adjacent buses (with/without GI #613 modeled) is as follows:

Fault Study (w/o GI #613)			
Location	**SLG (A)**	**LTL (A)**	**3PH (A)**
POI	-	-	-
[redacted] 138kV Bus	6349.3	6094.1	7119.8
[redacted] 138kV Bus	9759.3	10196.9	11951.9
[redacted] 138kV Bus	4899.1	4650.3	5494.0

Table 1. Fault Study Results without GI #613

Fault Study (w/ GI #613)			
Location	**SLG (A)**	**LTL (A)**	**3PH (A)**
POI	7516.8	6167.0	7375.3
[redacted] 138kV Bus	8438.2	6859.5	8092.9
[redacted] 138kV Bus	9828.1	10391.3	12123.7
[redacted] 138kV Bus	5055.6	5349.0	6290.6

Table 2. Fault Study Results with GI #613

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.

6.4 Electric System Protection Results and Grounding Requirements

For 138kV line protection, the Transmission Provider's System Protection Department utilizes permissive and line differential protection schemes integrated with digital communication infrastructure. Digital communication infrastructure for the interconnection customer's 138kV Interconnection Facilities will be the responsibility of said interconnection customer.

6.5 Energy Resource Interconnection Service Cost Estimate

In Table 3 below a summary is provided of the facilities and conceptual costs required to interconnect the GI #613 Project to the Transmission Provider's transmission system.

GI #613 [redacted] Project **Energy Resource Interconnection Service Facilities**	
ERIS Transmission Upgrades:	**Cost**
Interconnection Facilities:	
Approximately 30% of a new two-breaker 138kV station on the [redacted] 138kV transmission line	$739,500
Network Upgrades:	
Approximately 70% of a new two-breaker 138kV station on the [redacted] 138kV transmission line	$1,725,500
Reconductor [redacted] 138kV line (~[redacted] miles) with [redacted] conductor	$6,699,000
Subtotal	**$9,164,000**
Contingencies (~20.0%) (1)	$1,832,800
Subtotal	**$10,996,800**
Overheads (~7.25%) (2)	$797,268
ERIS – Total Estimated Cost (3)	**$11,794,068**

Table 3. Estimated GI #613 Energy Resource Interconnection Service Costs

(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.
(3) This cost estimate includes direct equipment, material, labor, and overheads as shown.

- Note that these estimates do not include the cost of the customer's equipment/facilities or required communication circuits for SCADA, PMU, and metering.
- Note that the overhead rates are subject to change during the year.
- Note that these costs assume the use of in-house resources.
- These are estimated costs only and final charges to the customer will be based on the actual construction costs incurred.
- These are non-binding conceptual level cost estimates that will be further refined upon the request and completion of the Facility Study.

7.0 Network Resource Interconnection Service (NRIS)

Network Resource Interconnection Service (NRIS) allows the Interconnection Customer to integrate its Generating Facility with the Transmission Provider's Transmission System in a manner comparable to that in which the Transmission Provider integrated its generating facilities to serve native load customers. The transmission system is studied under a variety of conditions to determine the transmission improvements/upgrades which are necessary.

7.1 Description of Power Flow Cases

For the Network Resource Interconnection Service study, two power flow cases were used to study the Transmission Provider's transmission system with westbound and eastbound transmission flows to determine the required Network Transmission Upgrades.

The WECC 2023 Heavy Summer base case was modified to represent a summer month with high west to east (eastbound) transfers across Midpoint West.

For the second case, a WECC 2022 Light Winter base case was modified to represent a shoulder month condition with high east to west (westbound) transfers across Midpoint West.

7.2 Network Resource Interconnection Service Transmission Upgrades

From the power flow/contingency analysis, the following Network Transmission upgrades were identified for the integration of GI #613 in addition to the Energy Resource generation interconnection facilities. A System Impact Study will ultimately be required to determine the specific network upgrades required to integrate the Project.

1. Replace [redacted] 6 Ω series reactor with a 6 Ω series reactor rated at 950/1140 amps
2. Reconductor [redacted] 138kV line (~[redacted] miles) with [redacted] conductor
3. Reconductor [redacted] 138kV line (~[redacted] miles) with [redacted] conductor

IPC projects queue GI #530, GI #551, GI #557, GI #567, GI #570, GI #578, GI #588, GI #590, GI #604, GI #605, GI #611, and GI #612 are senior queued projects in the affected area of IPC's transmission system. Idaho Power studied GI #613 with all Network Upgrades identified for senior queued projects as in service (Potential Contingent Facilities). Changes to senior queued projects including in-service date and withdrawal from the queue, may trigger a restudy associated with GI #613 Network Resource, NR, service, (some or all of the network upgrades identified for GI #530, GI #551, GI #557, GI #567, GI #570, GI #578, GI #588, GI #590, GI #604, GI #605, GI #611, and GI #612 may be required by GI #613).

7.3 Network Resource Interconnection Service Cost Estimate

Table 4 below is a summary of the Network Transmission generation interconnection facilities and conceptual costs required to interconnect the GI #613 Project to the Transmission Provider's transmission system for Network Resource Interconnection Service.

GI #613 [redacted] Project **Network Resource Interconnection Service Facilities**	
NRIS Transmission Upgrades:	**Cost**
Network Upgrades:	
Replace [redacted] 6 Ω series reactor with a 6 Ω series reactor rated at 950/1140 amps	$5,000,000
Reconductor [redacted] 138kV line (~[redacted] miles) with [redacted] conductor	$4,645,800
Reconductor [redacted] 138kV line (~[redacted] miles) with [redacted] conductor	$3,567,000
Subtotal	**$13,212,800**
Contingencies (~20.0%) (1)	$2,642,560
Subtotal	**$15,855,360**
Overheads (~7.25%) (2)	$1,149,514
NRIS – Subtotal	**$17,004,874**
ERIS – Total Estimated Cost	$11,794,068

NRIS – Total Estimated Cost (3)	**$28,798,942**

Table 4. Estimated GI #613 Network Resource Interconnection Service Costs

(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.
(3) This cost estimate includes direct equipment, material, labor, and overheads as shown.

- Note that these estimates do not include the cost of the customer's equipment/facilities or required communication circuits for SCADA, PMU, and metering.
- Note that the overhead rates are subject to change during the year.
- Note that these costs assume the use of in-house resources.
- These are estimated costs only and final charges to the customer will be based on the actual construction costs incurred.
- These are non-binding conceptual level cost estimates that will be further refined upon the request and completion of the Facility Study.

8.0 Description of Operating Requirements

The GI #613 Project is a combined PV and BESS and it has been assumed that the BESS will be charged via the PV output. In order to charge the BESS via IPC's transmission system, [redacted] will need to make an IPC Large Load Service request.

GI #613 will be required to control voltage in accordance with a voltage schedule as provided by Idaho Power Grid Operations. GI #613 will be required to manage the real power output of their generation project at the POI. Also, it may be beneficial for [redacted], for their own modeling compliance requirements, to install additional PMU devices at their facilities to monitor the generation source(s).

It is the generation Project's responsibility to provide reactive power capability of the Project to have a power factor operating range of at least 0.95 leading (absorbing) to at least 0.95 lagging (supplying) at the POI over the range of real power output (up to maximum output of the Project).

Identification of any additional equipment required at the plant to meet Idaho Power reactive power capability interconnection requirements will be provided in the System Impact Study if the generation interconnection customer chooses to move to the next study phase of the interconnection process.

The Project(s) 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 GI #613. 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 Facility Study should the generation interconnection customer choose to proceed to that phase of the interconnection process. Also, it may be beneficial for [redacted], for their own modeling compliance requirements, to install additional PMU devices at their facilities to monitor the generation's sources separately.

Additional operating requirements for this Project may be identified in the System Impact Study when it is performed.

9.0 Conclusion

GI #613 can be interconnected to the Idaho Power transmission system.

Interconnection requirements detailed in Section 6.5 totaling **$11,794,068** are required to interconnect the Project for Energy Resource Interconnection Service (ERIS) at the proposed [redacted] 138kV transmission line POI. If the Project interconnects for Network Resource Interconnection Service (NRIS), the cost to integrate the project is **$28,798,942**. Both the ERIS and NRIS may be reliant on facilities identified in senior queued generation interconnections.

A System Impact Study is required to determine the specific Transmission Network Upgrades required to integrate the Project for Network Resource Interconnection Service and to evaluate the system impacts (thermal overload, voltage, transient stability, reactive margin).

APPENDIX A

A-1.0 Method of Study

The Feasibility Study plan inserts the Project up to the maximum requested injection into the selected Western Electricity Coordinating Council (WECC) power flow case and then, using Power World Simulator or GE's Positive Sequence Load Flow (PSLF) analysis tool, examines the impacts of the new resource on Idaho Power's transmission system (lines, transformers, etc.) within the study area under various operating and outage scenarios. The WECC and Idaho Power reliability criteria and Idaho Power operating procedures were used to determine the acceptability of the configurations considered. The WECC case is a recent case modified to simulate stressed but reasonable pre-contingency energy transfers utilizing the IPC system. For distribution feeder analysis, Idaho Power utilizes DNV·GL's Synergi Electric software and EPRI's OpenDSS software.

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 Web site,

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
10/07/2021	1	SWL	Initial Report