GENERATOR INTERCONNECTION

SYSTEM IMPACT STUDY REPORT

for integration of the proposed

15 MW [redacted] PROJECT

IPC PROJECT QUEUE #519

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

For

Enerparc Inc., A Delaware Corporation

REPORT v.0

January 31, 2017

Revision History

Date	Revision	Initials	Summary of Changes
1/31/2017	0	PMA	SIS Report GI #519

Table of Contents

List of Tables

List of Figures

1.0 INTRODUCTION

Enerparc Inc., A Delaware Corporation (Enerparc) has contracted with Idaho Power Company (IPC) to perform a Generator Interconnection System Impact Study for the integration of the proposed 15 MW [redacted] Project (the Project). The Project is located in IPC's Western Region approximately [redacted] in Baker County, Oregon at [redacted] (See Figure 1: Location of [redacted] – GI # 507 in Appendix B). The Project is Generation Interconnect (GI) queue number 519 (GI #519).

The Project has applied to connect to the IPC transmission system for an injection of 15 MW at a single Point of Interconnection (POI) at a 69 kV voltage. The POI is located at [redacted], which is approximately 1 mile north of the Project. The POI is on IPC's [redacted] 69 kV line approximately [redacted] miles from the [redacted] station.

This report documents the basis for and the results of this feasibility study for the GI #519 Generation Interconnection Customer. The report describes the proposed project, the determination of project interconnection system impact and estimated costs for integration of the Project to the Idaho Power System. This report satisfies the System Impact Study requirements of the Idaho Power Tariff.

2.0 SUMMARY

Results from the Transmission System Steady State Thermal and Voltage Analysis indicated that interconnecting the [redacted] Project (GI #519) caused no thermal or voltage impacts that violated IPC planning criteria when the IPC system is normally aligned.

The IPC transmission system study showed adequate damping for all faults analyzed during the Transient Stability Analysis under both pre-project and post-project scenarios.

The Short Circuit Analysis and Protection results showed that the addition of the Project did not result in exceeding the existing short circuit limitations of neighboring breakers.

The Project will be required to control voltage in accordance with a voltage schedule as provided by Idaho Power Grid Operations. Therefore, GI #519 will be required to install a plant controller for managing the real and reactive power output of the 15 MW inverter array at the project POI. Also, the installation of a phasor measurement unit device (PMU) at the POI and the installation and maintenance costs associated with communication circuits needed to stream PMU data will be required in order to interconnect GI #519.

The System Impact Study results indicate that GI #519 will operate within an acceptable voltage range with the recommended upgrades when the IPC system is in a normal configuration. However, if the voltage falls outside of the acceptable range, reactive power and/or additional system upgrades are required to be implemented by GI #519 to aid in returning the POI voltage within the acceptable range. In an abnormal system configuration, as described in section 7.0, the Project will be required to operate and curtail output as described in section 7.0.

The total preliminary cost estimate to interconnect the [redacted] project to the [redacted] 69 kV line is $2,513,256, and includes the following tasks:

- Transmission line upgrades.
  - Install an additional 69 kV line switch on the [redacted] side of the POI.
- Substation upgrades.
  - Yard preparation of fenced yard.
  - Prefab control building with AC and DC systems installed.
  - Conduits and yard cables run between all yard apparatus/equipment and the control building.
  - 69 kV circuit breaker with disconnects.
  - Instrumentation transformers for protective relaying and metering.
  - Interconnect package.
    - SEL 421/411L Protective relaying panels with PMU capability
    - SEL 2506 mirror bit boxes with fiber communications.
    - Interconnect metering.
  - SCADA.
  - Upgrade the relaying at [redacted] for the [redacted] 69 kV line with SEL 421/411L relay panels.

The cost estimate includes direct equipment and installation labor costs, indirect labor costs and general overheads, and a contingency allowance. 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 estimate of $2,513,256 does not include the cost of:

- The customer's equipment/facilities.
- The land needed for the interconnection yard. This land will be IPC owned but is the responsibility of the interconnection customer to permit and purchase.
- The cost of the dedicated communications circuits required.
  - Interconnection Customer to provide one dedicated 64 kilo-bit per second DDS leased line communications circuit between the POI and IPC Boise Bench substation for PMU data.
  - Interconnection Customer to provide one dedicated 64 kilo-bit per second DDS leased line communications circuit between the POI and IPC Boise Bench substation for SCADA data.
  - Interconnect Customer to provide one POTS (Plain Old Telephone Service) dial-up circuit for querying the revenue meter at the generation interconnection site. The dial-up circuit should be of sufficient quality to accommodate a dial-up modem connection.

  - Any 69 kV connection between the Project and the POI including the line termination apparatus. These facilities will be constructed, owned and operated by the Interconnection Customer.
- The overhead rates are subject to change during the year and tax gross-up percentages vary from year to year.
- These are estimated costs only and final charges to the customer will be based on the actual construction costs incurred, including overheads and tax gross-up.

These are non-binding conceptual level cost estimates that will be further refined upon the request and completion of Transmission and Distribution Facility Studies.

Generator interconnection service, either as an Energy Resource or a Network Resource, does not in any way convey any right to deliver electricity to any specific customer or point of delivery.

3.0 SCOPE OF INTERCONNECTION SYSTEM IMPACT STUDY

This Interconnection System Impact Study was completed, in accordance with Idaho Power Company Standard Generator Interconnection Procedures, to provide an evaluation of the impacts the interconnection of the proposed generating project would have to the Idaho Power system. As listed in the System Impact Study Agreement, the Interconnection System Impact Study report provides the following information:

- Identification of additional transformer load tap changer operations, voltage fluctuations (flicker) and additional feeder losses.
- Identification of required reactive power support.
- Identification of islanding conditions.
- Identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection.
- Identification of any thermal overload or voltage limit violations resulting from the interconnection.
- Identification of any angular instability.
- Description and non-binding estimated cost of facilities required to interconnect the Small Generating Facility to the IPC System and to address the identified short circuit and power flow issues.

All generation projects in the area ahead of GI #519 in the IPC generation queue, and their associated transmission system improvements, were modeled in the preliminary power flow analysis to evaluate the thermal and voltage impacts of interconnecting GI #519.

A current list of these projects can be found in the Generation Interconnection folder located on the Idaho Power web site at the link shown below:

http://www.oatioasis.com/ipco/index.html.

4.0 DESCRIPTION OF PROPOSED GENERATING PROJECT

[redacted], GI #519, consists of a single 15 MW photovoltaic solar plant which requested to be connected to Idaho Power's [redacted] 69 kV line. The Project will use [redacted]. The project will use a total of [redacted]. Each inverter will be connected to a 1.2 MVA transformer with a fused disconnect to step-up the voltage from [redacted] V to 69 kV. The DC Capacity of the system is [redacted].

The Project's projected in-service date was not included in the application.

The single-line drawing provided by the Interconnection Customer details a Wye-Grounded-Wye-Grounded transformer that satisfies IPC Interconnection requirements. Idaho Power also requires transmission interconnected generators to be a source for ground current contributions achieved by proper selection of transformer windings at the point of interconnection.

The inverter system is capable of remote reactive power control through various functions including voltage dependent reactive power control, as well as real power control. Plant level control will be provided with the addition of an external plant control and communications system. The inverter specified is UL1741 listed with Anti-Islanding Protection.

For Interconnections of 3MW and greater, the Interconnection Customer will install equipment to receive signals from Idaho Power Grid Operations for Generation Output Limit Control ("GOLC").

5.0 DESCRIPTION OF FACILITIES

5.1 Description of Transmission Facilities

The [redacted] project interconnection to the [redacted] 69 kV line was studied in this System Impact study. All generation projects in the area ahead of the Project in the IPC generation queue and their associated transmission system improvements were modeled in a preliminary power flow analysis to evaluate the system impact of interconnecting GI #519.

5.2 Description of Existing Substation Facilities

The Project is not designed to connect to an IPC substation. The POI is approximately [redacted] miles from the [redacted] substation.

5.3 Description of Existing Distribution Facilities

The Project is not designed to connect to any IPC distribution facilities.

5.4 Description of Required Facility Upgrades and Cost Estimate

The Project will be required to provide a plant controller that will operate the inverter system using advanced inverter functionality in order to regulate voltage according a voltage schedule that will be provided by Idaho Power.
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. The preliminary estimated cost to interconnect GI #519 to the IPC System is $2,513,256.

- Transmission line upgrades.
  - Install an additional 69 kV line switch on the [redacted] side of the POI.
- Substation upgrades.
  - Yard preparation and fenced yard.
  - Prefab control building with AC and DC systems installed.
  - Conduits and yard cables run between all yard apparatus/equipment and the control building.
  - 69 kV circuit breaker with disconnects.
  - Instrumentation transformers for protective relaying and metering.
  - Interconnect package.
    - SEL 421/411L Protective relaying panels with PMU capability
    - SEL 2506 mirror bit boxes with fiber communications.
    - Interconnect metering.
  - SCADA.
  - Upgrade the relaying at [redacted] for the [redacted] 69 kV line with SEL 421/411L relay panels.

See the conceptual-level cost estimate below in Table 1.

Table 1: Conceptual-level Cost Estimate for GI #435

Item of Work	Estimate
Substation upgrades	$1,687,800
Distribution upgrades	$0
Transmission upgrades	$133,400
Unloaded costs	$1,821,200
Contingency 20% (1)	$364,240
Total unloaded costs	$2,185,440
Overheads (2)	$327,816
Total loaded costs	$2,513,256

Total Conceptual-level Cost Estimate in 2015 dollars (3) **$2,513,256**

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

- Note that these estimates do not include the cost of:
  - The customer's equipment/facilities.
  - The land needed for the interconnection yard. This land will be IPC owned but is the responsibility of the interconnection customer to permit and purchase.
  - The cost of the dedicated communications circuits required.
    - Interconnection Customer to provide one dedicated 64 kilo-bit per second DDS leased line communications circuit between the POI and IPC Boise Bench substation for PMU data.
    - Interconnection Customer to provide one dedicated 64 kilo-bit per second DDS leased line communications circuit between the POI and IPC Boise Bench substation for SCADA data.
    - Interconnect Customer to provide one POTS (Plain Old Telephone Service) dial-up circuit for querying the revenue meter at the generation interconnection site. The dial-up circuit should be of sufficient quality to accommodate a dial-up modem connection.
  - Any 69 kV connection between the Project and the POI including the line termination apparatus. These facilities will be constructed, owned and operated by the Interconnection Customer.
- The overhead rates are subject to change during the year and tax gross-up percentages vary from year to year.
- These are estimated costs only and final charges to the customer will be based on the actual construction costs incurred, including overheads and tax gross-up.
- These are non-binding conceptual level cost estimates that will be further refined upon the request and completion of Transmission and Distribution Facility Studies.

Cost estimates include direct equipment and installation labor costs, indirect labor costs and general overheads, and a contingency allowance. These are preliminary cost estimates only and final charges to the customer will be based on the actual construction costs incurred.

6.0 DESCRIPTION OF POWER FLOW CASES

Studies were performed on both the 69 kV electrical system that the Project ties to, as well as the Bulk Electric System (BES) Brownlee East transmission path (WECC Path #55).

The 69 kV Power Flow cases were based on a Light Load model containing all active projects in the Generation Interconnection queue prior to this Project. The 69 kV [redacted] line was studied with the line normally open on the [redacted]. The Project's impact on the steady state thermal and voltage limits of the 69 kV system were evaluated.

The Project's impact on the Brownlee East transmission path (WECC Path #55) was evaluated in this Transmission System Impact Study. In addition, the Idaho-Northwest transmission path (WECC Path #14) which is in series with the Brownlee East transmission path was studied at its rated West-to-East transfer capacity.

The Idaho-Northwest transmission path (WECC Path #14) is defined as the sum of the flows on the following five lines:

- Oxbow-Lolo 230kV
- Hells Canyon-Hurricane 230kV
- North Powder-La Grande 230kV
- Hines-Harney 115kV
- Hemingway-Summer Lake 500kV

The Brownlee East transmission path (WECC Path #55) is defined as the sum of the flows on the following seven lines:

- Brownlee-Boise Bench #1 230kV
- Brownlee-Boise Bench #2 230kV
- Brownlee-Boise Bench #3 230kV
- Brownlee-Horse Flat #4 230kV
- Brownlee-Ontario 230kV
- Oxbow-Starkey 138kV
- Quartz-Ontario 138kV

For this generation interconnection Transmission System Impact Study, the flow on the Idaho-Northwest transmission path was modeled at [redacted] MW West-to-East and the Brownlee East transmission path was modeled at [redacted] MW West-to-East. The paths were stressed to these specific levels in order to determine if the addition of the Project's 15 MW degraded the existing Brownlee East path's transfer capability.

7.0 STEADY STATE THERMAL AND VOLTAGE ANALYSIS RESULTS (TRANSMISSION)

For the 69 kV steady state thermal and voltage analysis, the results show that under system normal conditions, IPC equipment near GI #519 remains within its thermal and voltage limits both before and after the project is added. However, with the system abnormally configured with the 69 kV line closed through to [redacted] line breaker open, the [redacted] station shows high voltage when the Project is at maximum 15 MW output. In this abnormal system configuration, the Project will be required to absorb maximum reactive power, as described in section 8.0, and curtail output to bring the 69 kV system voltage back within limits.

Additionally, for this project located West of Brownlee East (WECC Path #55), the studies show that the project does not degrade the existing Brownlee East or Idaho-Northwest transmission path capabilities. Sufficient available transmission capacity exists on WECC Path #55 to integrate the generation.

Voltage flicker at startup and during operation will be limited to less than 5% as measured at the POI. The project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-1992 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*.

8.0 DESCRIPTION OF OPERATING REQUIREMENTS (REACTIVE MARGIN ANALYSIS)

The Project shall be capable of injecting reactive power (over-excited) and absorbing reactive power (under-excited) equal to 7.26 MVAR at all active power output between 20% and 100% of nameplate active power rating.

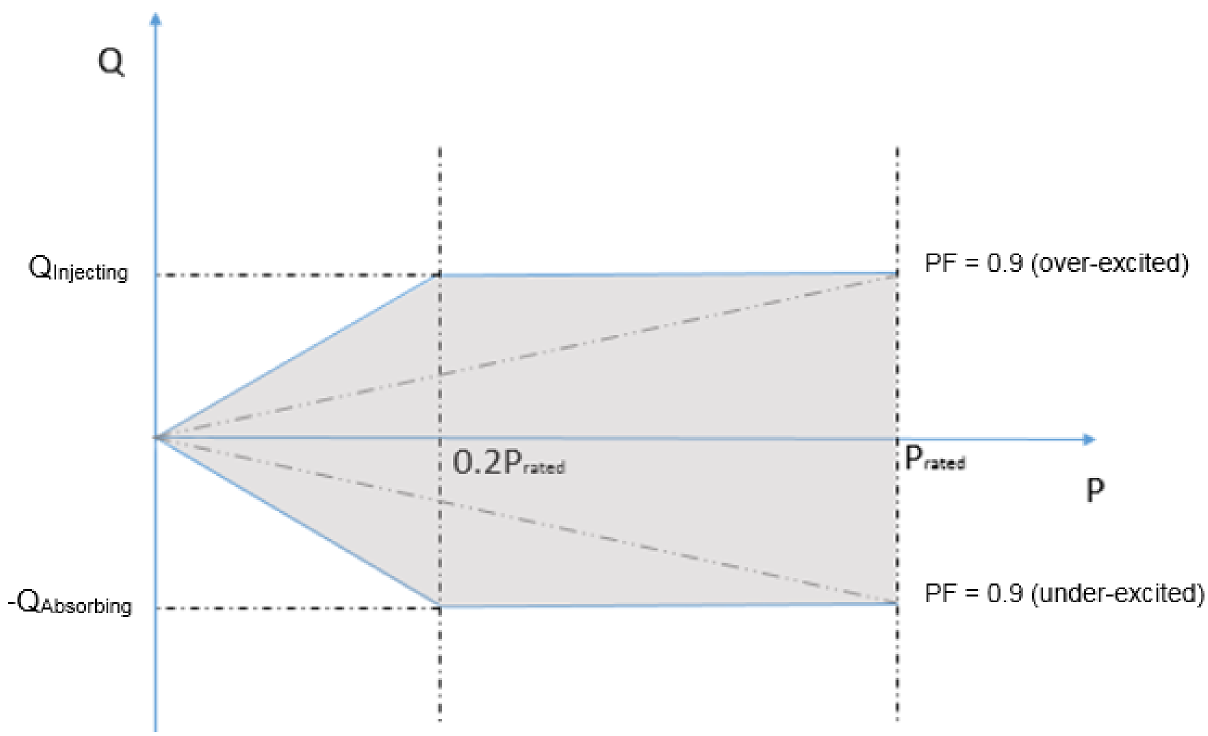

Figure 1: Operating Requirements

Idaho Power has determined that the inverter selected by the Project meets the reactive power capability requirements.

The Project will be required to control voltage in accordance with a voltage schedule as provided by Idaho Power Grid Operations. Therefore, GI #519 will be required to install a plant controller for managing the real and reactive power output of the 15 MW inverter array at the project POI.

Voltage flicker at startup and during operation will be limited to less than 5% as measured at the POI. The allowable voltage flicker limit is further reduced during operation due to multiple voltage fluctuations per hour or minute, per Idaho Power's T&D Advisory Information Manual.

The Project is required to comply with the applicable voltage fluctuation limits found in IEEE Standard 1453-2004 IEEE Recommended Practice *for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems.*

9.0 STEADY STATE THERMAL AND VOLTAGE ANALYSIS RESULTS (DISTRIBUTION)

The Project is not designed to connect to any IPC distribution facilities.

10.0 SHORT CIRCUIT STUDY RESULTS

IPC performed a System Protection analysis and a fault study.

[redacted] connection is being proposed between [redacted].

[redacted]

Figure 2: Existing [redacted] 69 kV line

[redacted]

Figure 3: [redacted] 69 kV line with proposed generator and 69 kV switch

[redacted] has a single relay tripping the single 061A breaker for faults in both directions but no means for transfer tripping. [redacted] must still be set to detect and relay for faults close-in to [redacted] in the event of a [redacted] breaker failure. Similarly, [redacted] must also be able to relay for faults close-in to [redacted] The addition of [redacted] desensitizes the relaying to the point that the relays at either substation cannot protect to the end of the line.

The [redacted] relaying will need to be replaced with a SEL 421/411L panel on the [redacted] line. The [redacted] relaying will also need to be replaced with a SEL 421/411L panel on the W[redacted] line. Operating the switch between [redacted] as normally open, (078T1 or a new N.O. switch) does not eliminate this requirement since the switch can be closed again.

Maintenance on [redacted] 061A typically involves closing 078T2, which puts the Baker load on the [redacted] line, and opening 078T4 outside of [redacted], which creates a radial line from [redacted] source) that picks-up [redacted] Because [redacted] is proposed between [redacted] an additional line switch on the [redacted] side of the POI is required to achieve the same switching configuration.

Station Infrastructure:

A Non-Utility Generator (NUG) connecting to a two-terminal line will require one breaker and will convert the line from a two-terminal to three-terminal line.

The following is a typical NUG terminal line tap.

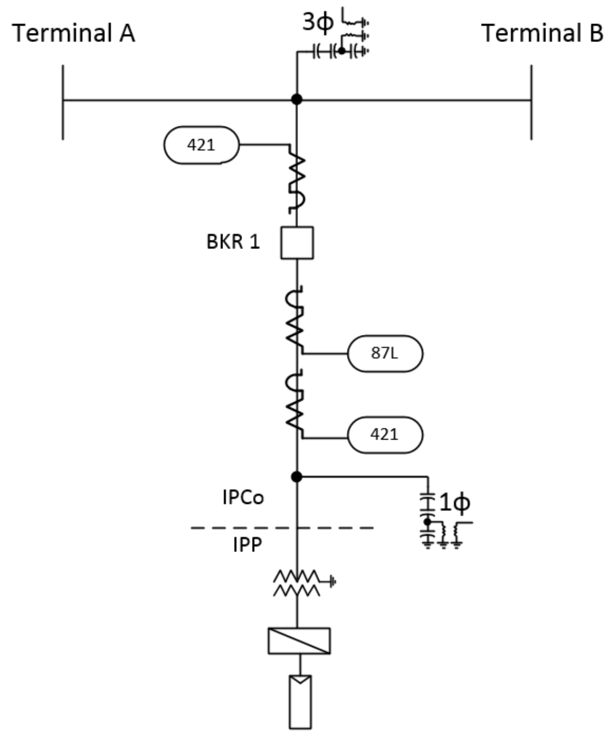

Figure 4: Operating Requirements

Shared facilities, (control house, ground grid, etc) are assumed in the above configuration. If separate facilities are required install dual SEL-2506 Mirrored Bit® boxes at each site and connect with fiber.

The NUG must be a source of ground current for line relaying. This is typically achieved through the proper selection of transformer configurations. For example, an autobank with a delta tertiary is a source of ground current, (other configurations can and do exist).

Fault Study:

With all breakers and switches closed between [redacted] -

The fault duty at the approximate POI (with no NUG modeling) is as follows:

Single-Line-to-Ground Fault Duty = 3211 A
Line-to-Line Fault Duty = 2583 A

Three-Phase Fault Duty = 2982 A

The sequence network reductions at the point of interconnection are as follows:

Positive Sequence: R = 2.921 Ω, X = 12.995 Ω
Negative Sequence: R = 2.924 Ω, X = 12.997 Ω
Zero Sequence: R = 1.946 Ω, X = 10.304 Ω

With an open switch between [redacted] -

The fault duty at the approximate POI (with no NUG modeling) is as follows:

Single-Line-to-Ground Fault Duty = 2859 A
Line-to-Line Fault Duty = 2247 A
Three-Phase Fault Duty = 2594 A

The sequence network reductions at the point of interconnection are as follows.

Positive Sequence: R = 2.040 Ω, X = 15.209 Ω
Negative Sequence: R = 2.043 Ω, X = 15.210 Ω
Zero Sequence: R = 1.981 Ω, X = 10.915 Ω

The fault current contribution from the PV generators does not result in exceeding any circuit breaker rating.

11.0 TRANSIENT STABILITY STUDY RESULTS

A transient stability analysis was completed using the WECC 2016 Heavy Summer operating case (16HS3a). The [redacted] 69kV line was modeled with a normal open west of [redacted] substation. Faults were simulated on the nearby power system. The system was found to be stable with or without the GI #519 generation interconnection for all faults.

As a check, the system was also modeled with the [redacted] 69kV line tied through without a normal open. Again the system was found to be stable with or without the GI #519 generation interconnection. However, it was found that the GI project will trip on the customer supplied overvoltage settings for a [redacted] bus fault if the [redacted] 69kV line is tied through.

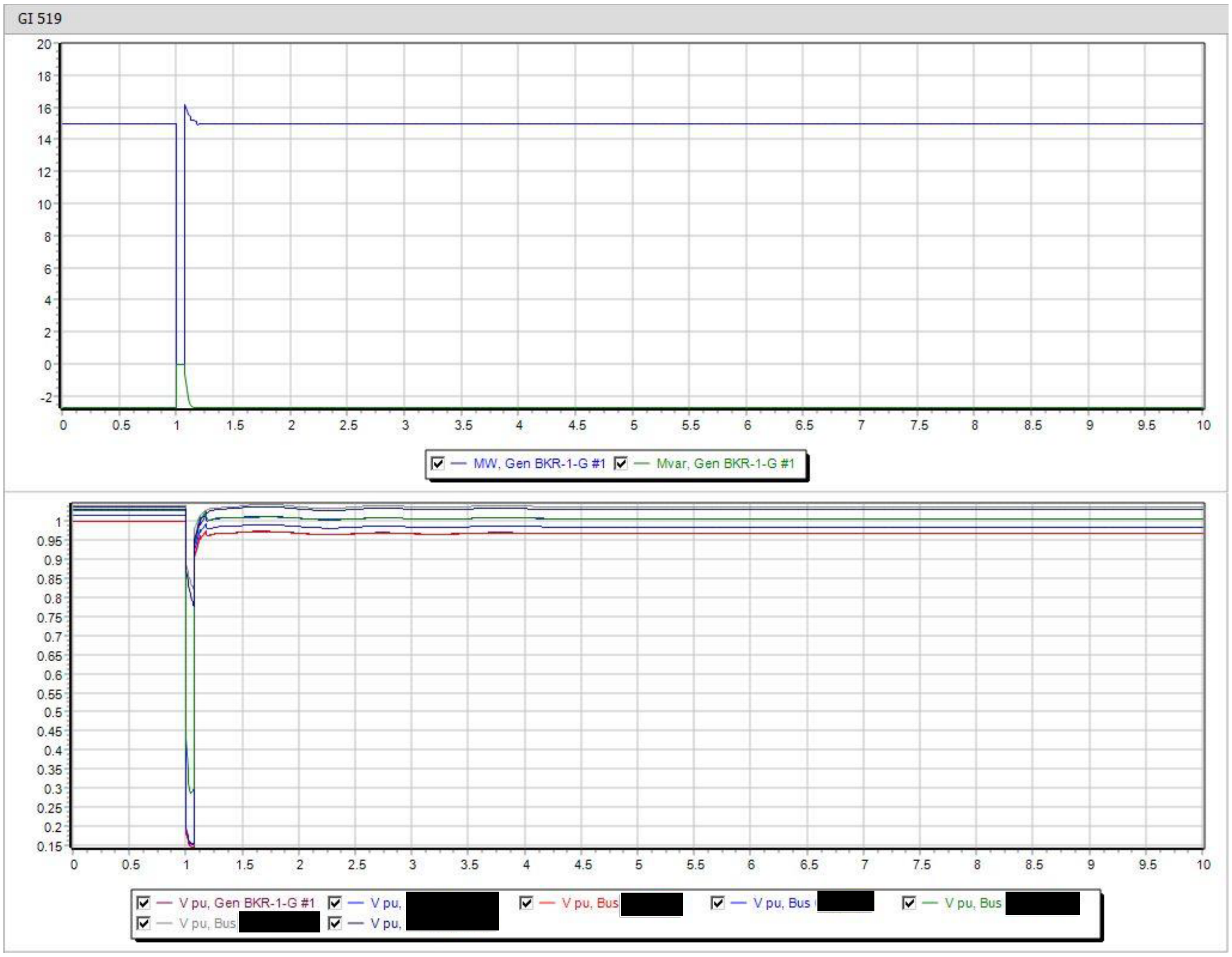

Figure 5: [redacted] 230kV – 3 Phase Fault – 078T1 Open

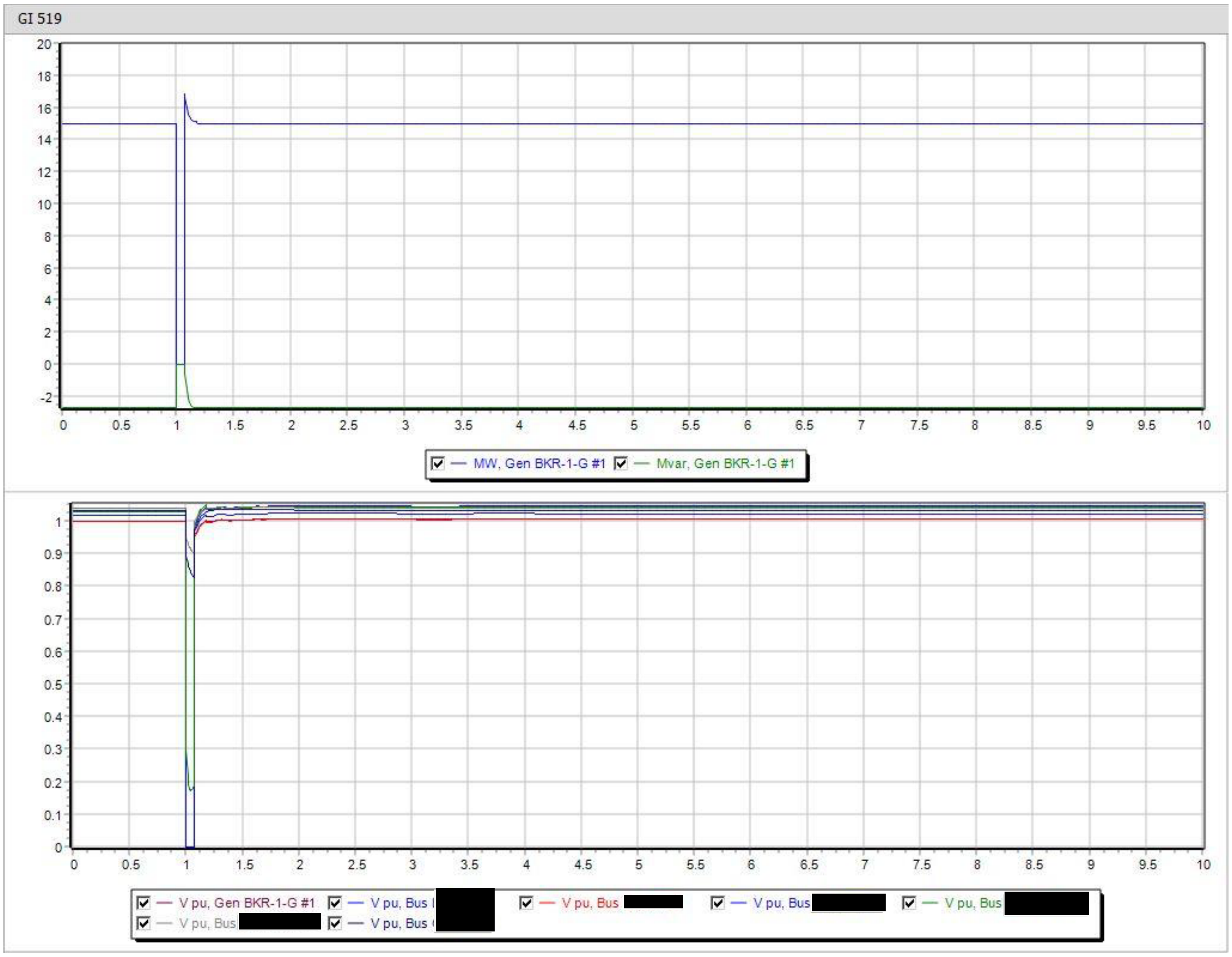

Figure 6: [redacted] 138kV – 3 Phase Fault – 078T1 Open

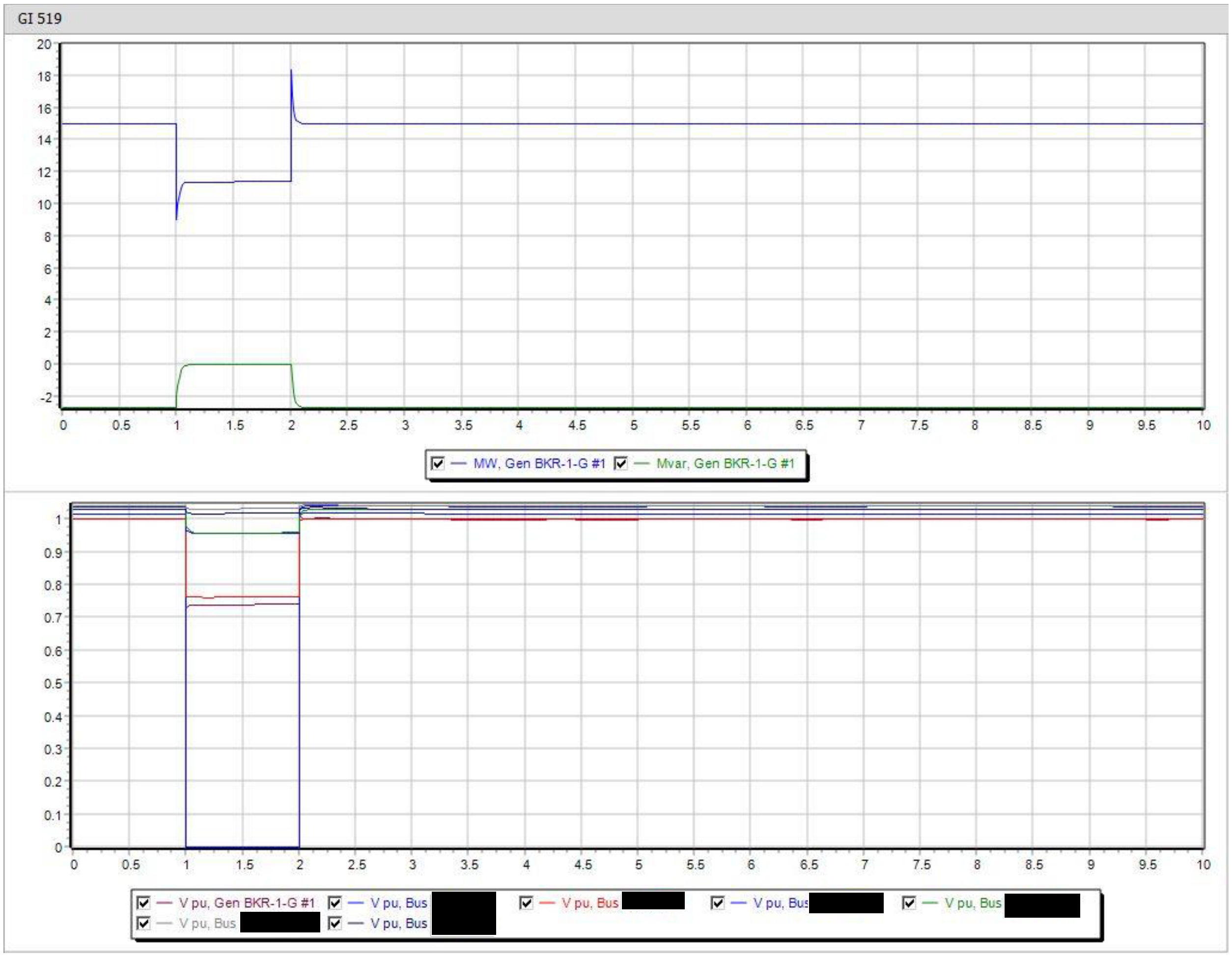

Figure 7: [redacted] – 3 Phase Fault – 078T1 Open

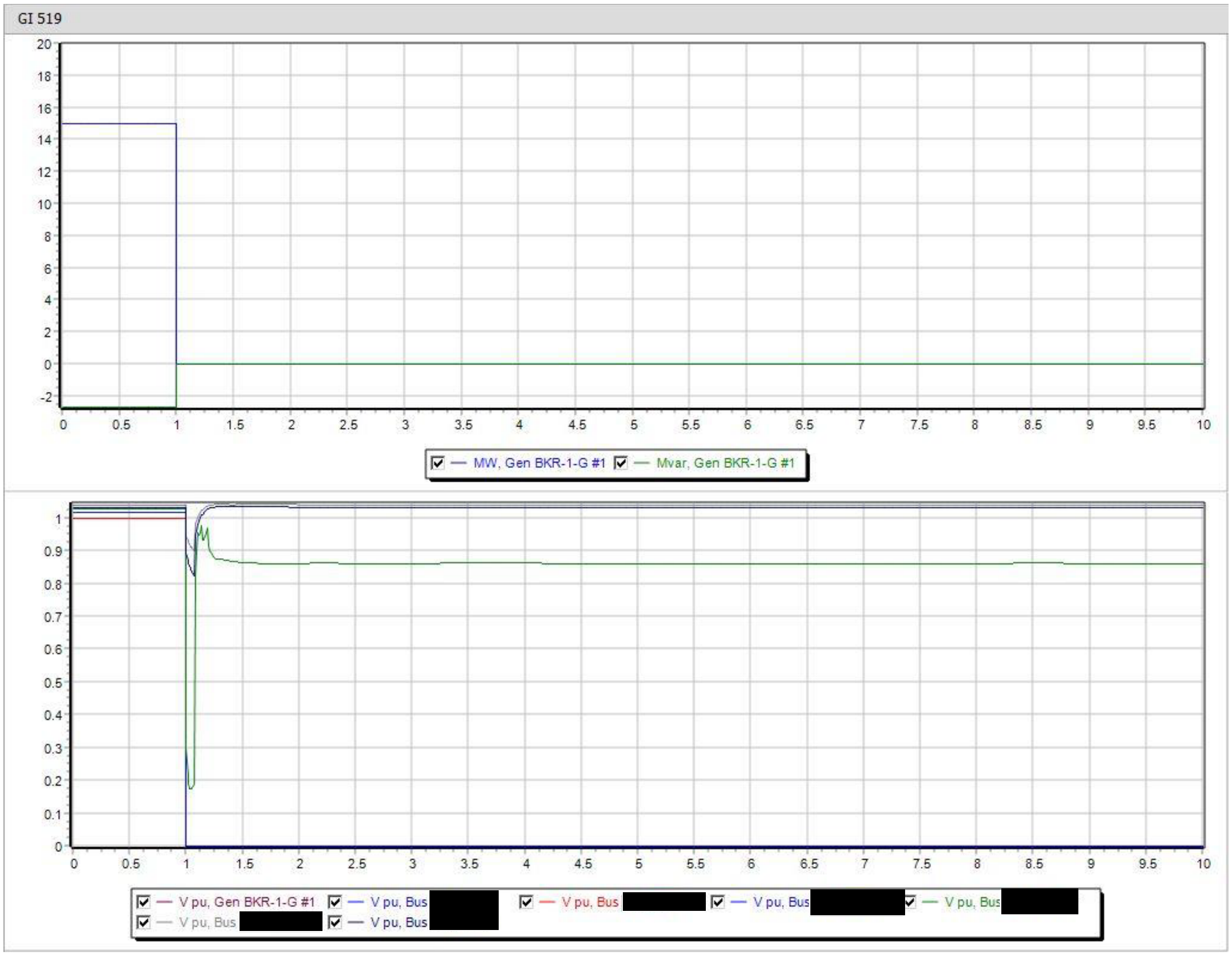

Figure 8: [redacted]s – 3 Phase Fault – 078T1 Open

12.0 CONCLUSION

The requested interconnection of the [redacted] Project (GI #519) to Idaho Power's system was studied. The location of the project is in Idaho Power's Western Region service territory in Baker County, Oregon.

The specific point of interconnection studied is on the 69 kV transmission line. The POI is on IPC's [redacted] – [redacted] 69 kV line approximately [redacted] miles from the [redacted] station. The proposed 15 MW of solar generation will interconnect at a new 69 kV substation to be constructed at the POI connected to the solar array.

The System Impact Study results indicate that GI #519 will operate within an acceptable voltage range with the recommended upgrades when the IPC system is in a normal configuration. However, if the voltage falls outside of the acceptable range, reactive power and/or additional system upgrades are required to be implemented by GI #519 to aid in returning the POI voltage within the acceptable range. In an abnormal system configuration, as described in section 7.0, the Project will be required to operate and curtail output as described in section 7.0.

The IPC transmission system studies show adequate damping for all faults analyzed during the Transient Stability Analysis under both pre-project and post-project scenarios.

This assessment evaluated the Project impact on the IPC electric system due to this project. Upgrades will be required at the estimated cost to connect this project to the existing IPC system. The implementation of a plant controller to operate the Project inverter system using an advanced inverter control mode will be required.

The Short Circuit Analysis and Protection results showed that the addition of the Project did not result in exceeding the existing short circuit limitations of neighboring breakers.

All generation projects in the area ahead of this project in the IPC generation interconnection queue and their associated transmission system improvements were modeled in a preliminary power flow analysis to evaluate the impact of interconnecting GI #519. The results and conclusions of this System Impact Study are based on the realization of these projects in the unique queue/project order.

The estimated cost to interconnect GI #519 to the IPC System at the proposed point of interconnection is approximately $2,513,256.

Appendix A – Method of Study

A-1.0 Method of Study

The System Impact Study plan inserts the Project up to the maximum requested injection into the selected Western Electric Coordinating Council (WECC) power flow case and then, using PowerWorld Simulator or GE's Positive Sequence Load Flow (PSLF) analysis tool, the impacts of the new resource on Idaho Power's transmission system (lines, transformers, etc.) within the study area are analyzed. 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 Advantica's SynerGEE 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. This states, 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 (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

Idaho Power Company (IPC) requires interconnected transformers 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 at
http://www.idahopower.com/aboutus/BusinessToBusiness/GenerationInterconnect

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.

Appendix B - LOCATION OF [redacted] GI #519

Figure B-1: Location of [redacted] – GI #519

[redacted]

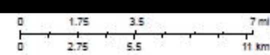

Figure B-2: Proposed location of [redacted] – GI #519

[redacted]