GENERATOR INTERCONNECTION
SYSTEM IMPACT STUDY REPORT

for integration of the proposed

[redacted]

IPC PROJECT QUEUE # 503

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

DRAFT REPORT v.2

November 23, 2016

Revision History

Date	Revision	Initials	Summary of Changes
10/5/2016	0	PMA	Issued for review.
11/3/2016	1	PMA	Revised to include three phase PLC for affected system.
11/23/2016	2	PMA	Revised to change to dual (two phase) PLC

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1.0 EXECUTIVE SUMMARY

1.1 Introduction

[redacted] has contracted with Idaho Power Company (IPC) to perform a Generator Interconnection System Impact Study (SIS) for the integration of the proposed 20MW [redacted] photovoltaic project (the Project). The Project is located in IPC's Southern Region in [redacted] in Twin Falls County, Idaho. The Project is Generation Interconnect (GI) queue number 503 (GI #503). The specific point of interconnection (POI) studied is the 345 kV [redacted] Transmission Line jointly owned by IPC and [redacted], approximately [redacted].

On behalf of, and with the oversight of Idaho Power Company, POWER Engineers performed this SIS under the Idaho Power Tariff.

This report documents the basis for and the results of this SIS for the GI #503 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 SIS requirements of the Idaho Power Tariff.

1.2 Purpose of Generator Interconnection SIS

A Transmission System Impact Study is required to determine if any additional network upgrades are required to integrate this project into the IPC transmission system and to evaluate system impacts (thermal, voltage, transient stability, reactive margin). 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.

1.3 Background/SIS Recommendations

The system impact of interconnecting the 20 MW solar generation project to IPC's 345 kV [redacted] Transmission Line was evaluated. Power flow, Transient, Post-Transient (Reactive Margin), Low Voltage Ride Through and Short Circuit analyses indicate that interconnecting of the [redacted] project, GI #503, is feasible and will have a negligible impact on the surrounding systems.

In addition, [redacted], GI #503, will meet the power factor requirements required by IPC without any additional required shunt reactive compensation. GI #503 will be required to control voltage in accordance with a voltage schedule as provided by Idaho Power Grid Operations. Therefore, GI #503 will utilize the plant controller, required for the GI #502 interconnection for managing the real and reactive power output of the 20 MW inverter array at the project POI, and a phasor measurement unit device (PMU) at the POI.

Connecting the Project to the [redacted] 345 kV line will require the following:

1) A new 345/138 kV class substation with a 345 kV tapped connection at the POI.
2) Replace protection relays at [redacted] and [redacted] substations.
3) Replace PLC communication equipment at [redacted] & [redacted] with dual (two phase) PLC communication equipment.
4) Add dual (two phase) PLC communication equipment and protective relaying at the interconnection.

When compared against the performance of the present system (pre-project), studies indicate that there is no significant degradation in system protection or stability with the project in service via a tapped connection. Worst case fault (near the POI) clearing time increases from an average of 4.5 cycles to 9.5 cycles. Transient studies indicate that this does not result in system performance degradation. See Appendix A-3.2 for detailed transient voltage and frequency plots.

The **total preliminary cost estimate** to interconnect the [redacted] project is $0. This cost estimate assumes that the necessary system upgrades were performed and paid for under the [redacted] project.

<u>Additional Communication Requirements</u>:

The ability to remotely interrogate the relaying for operational analysis and maintenance is also required. Additional communications to support functions such as PMU, SCADA, Metering, GOLC, etc. will be required. These requirements may result in the need for additional infrastructure and this cost is not included in the preliminary cost estimate.

The following are the typical communication requirement for various functions:

- The Interconnection Customer to deliver dedicated 19.2kbps DDS service from POI demark to [redacted] Substation for SCADA usage.
- The Interconnection Customer to deliver dedicated 19.2kbps DDS service from POI demark to [redacted] Substation for PMU usage.
- The Interconnection Customer to deliver modem capable POTS service to POI demark for IPCO usage.
- The Interconnection Customer is responsible for any high voltage protection of circuits at POI mandated by 3rd party service provider.

2.0 SCOPE OF INTERCONNECTION SIS

The Interconnection SIS was conducted and prepared in accordance with Idaho Power Company's Standard Generator Interconnection Procedures to provide an evaluation of the system impact of the interconnection of the proposed generating project to the Idaho Power system. As listed in the Interconnection System Impact Study agreement, the Interconnection System Impact Study report provides the following information:

- Two 345kV POI options where studied
  - Option 1 - tap option, i.e. single 345kV breaker
  - Option 2 - 345kV three breaker ring
- Identification of transient stability voltage or frequency violations for both options described above.
- Preliminary identification of any circuit breaker short circuit capability limits exceeded as a result 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 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 web site at the link shown below:

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

3.0 DESCRIPTION OF PROPOSED GENERATING PROJECT

[redacted], GI #503, proposes to interconnect to the 345 kV Idaho Power transmission system with a total injection of 20 MW (maximum project output) using [redacted] inverters. The interconnection point is IPC's 345 kV [redacted] Transmission line. This project's projected in-service date is [redacted].

Table 1: Project Specifications

Project Location	[redacted]
Number and Type of Generators	[redacted]
Individual Generator Nameplate Rating	[redacted]
Total Output Power Rating	19,992kW (Summer) / 19,992kW (Winter) 22,200kVA (Summer) / 22,200kVA (Winter)
Rated Power Factor	0.9 Leading / 0.9 Lagging
New Step-Up Transformer	(12) 1,850 kVA, 3-phase, 0.385/34.5 kV, Z = 5.75% on 1,850 kVA base

New Step-Up Transformer	(1) 43 MVA, 3-phase, 34.5/345/13.8 kV, Z = 9% on 25.81 MVA base
Interconnection Voltage	345 kV

The cost estimate includes direct equipment and installation labor costs, indirect labor costs, general overheads, and a contingency allowance. These are only cost estimates 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 $0 does not include the cost of the customer's owned equipment to construct the solar generation site or the cost of communications for SCADA, Phasor Measurement Unit (PMU) and metering.

Additional Communication Requirements:

The ability to remotely interrogate the relaying for operational analysis and maintenance is also required. Additional communications to support functions such as PMU, SCADA, Metering, GOLC, etc. will be required. These requirements may result in the need for additional infrastructure and this cost is not included in the preliminary cost estimate.

The following are the typical communication requirement for various functions:

- The Interconnection Customer to deliver dedicated 19.2kbps DDS service from POI demark to [redacted] Substation for SCADA usage.
- The Interconnection Customer to deliver dedicated 19.2kbps DDS service from POI demark to [redacted] Substation for PMU usage.
- The Interconnection Customer to deliver modem capable POTS service to POI demark for IPCO usage.
  The Interconnection Customer is responsible for any high voltage protection of circuits at POI mandated by 3rd party service provider.

4.0 DESCRIPTION OF EXISTING TRANSMISSION FACILITIES

The [redacted], GI #503, interconnection to the [redacted] 345 kV line was identified as the preferred option. The Project is located adjacent to the proposed POI.

After reviewing all generation projects in the area ahead of this project in the IPC generation queue and [redacted] interconnection queue, there were no additional projects that were modeled in the analysis to evaluate the impact of interconnecting the GI #503 project. The GI#502 [redacted] project was modeled in this project as being in-service prior to this project GI#503.

Power flow analysis indicated that a 20 MW injection at the POI, considered in this study, is feasible and will not require any transmission system improvements in addition to those prescribed for the [redacted] project.

5.0 EXISTING TRANSMISSION COMMITMENTS

The proposed intertie site lies on the 345 kV [redacted] transmission line. The WECC 2015 Path Rating Catalog identifies the line as [redacted]

- Location: [redacted]
- Definition: [redacted] 345 kV line. The metering point is considered to be at [redacted].
- Transfer Limit:
  - [redacted]
  - [redacted]W
  - The capacities listed above are non-simultaneous ratings of the line.
  - Simultaneous ratings are dependent on [redacted] net control area operations. Seasonal System Operating Limits (SOLs) may be more restrictive for operating [redacted]
- Allocation:
  - The transfer capability of the path is allocated as follows:

Ownership	**Allocation**
[redacted]	[redacted]
[redacted]	[redacted]

2016 Summer Season Path System Operating Limits (SOL)

Path Description	Path No.	Catalog Rating (MW)	Path Limitation	2016 Summer SOL (MW)	2016 Spring SOL (MW)	2015-16 Winter SOL (MW)	2015 Summer SOL (MW)
[redacted]	[redacted]	[redacted]	Thermal	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	Thermal	[redacted]	[redacted]	[redacted]	[redacted]

6.0 DESCRIPTION OF POWER FLOW CASES

The case used for the study is the Western Electricity Coordination Council (WECC) 2019 Heavy Summer Operating Base Case. This case was chosen as a power flow base case for this SIS to represent summer conditions with transfer limit flow on [redacted] and [redacted], as defined in the WECC 2015 Path Rating Catalog. This case has undergone review and updates by Idaho Power and [redacted].

The base case was developed to include the proposed GI #502 20 MW PV generation project and the GI #503 20 MW PV generation project. Idaho Power obtained appropriate customer data from the GI #503 20 MW PV generation project sponsor with adequate detail. The base case was benchmarked and compared to the post-Project case to determine the system impact of the proposed GI #503 20 MW Project interconnection on Idaho Power and surrounding transmission system.

[redacted]

7.0 STUDY RESULTS

7.1 Power Flow Results (Thermal and Voltage Analysis)

Power Flow Analysis was performed on both the pre- and post-Project cases described above. The base cases were used to simulate the impact of the proposed GI #503 20 MW solar Project interconnection during normal operating conditions and contingency operation (TPL-001-4) for the 2019 timeframe. Mitigation of any adverse changes in loading or voltage from pre- to post-Project was considered.

The contingencies simulated include:

- All transformers and transmission lines connected one bus away from the GI #503 Project.
- GI #502 and GI #503 Projects

The results of the power flow studies were evaluated using the most recently approved WECC Criterion for Transmission System Planning Performance (TPL-001-WECC-CRT3) and IPC Reliability Criteria. The power flow analysis related evaluation criteria that were used are summarized below:

- Pre-contingency bus voltages within the study area must be between 0.95 per unit and 1.05 per unit.
- Maximum voltage deviation allowed at all buses under contingency conditions will be 8% for N-1.

Power flow solution was achieved for each of the N-1 outages simulated. Key findings from the power flow analysis are as follows:

- Overloading. There were no significant overloads for the 345kV interconnection.
- Voltage Deviation. There were no significant voltage deviations in the power flow analysis.
- Voltage Violations. There no significant voltage violations in the power flow analysis.

7.2 Reactive Compensation Requirements

The installed reactive power capability of the project must have a power factor operating range of 0.95 leading to 0.95 lagging at the POI over the range of real power output (up to maximum output of 20 MW).

From the inverter specification sheet provided by the developer the maximum reactive power of ± 807 kVAr per inverter. It is assumed there is one inverter per inverter step-up transformer for a total of 12 inverters. The reactive capability at rated power is ≥ 0.9 PF. Hence, [redacted] at rated power should be able to provide ± 9.68 MVAr.

[redacted]

Power flow analysis indicates that the reactive compensation range of the proposed GI #503 does have sufficient capacity to provide a 0.95 lagging power factor at full output of 20 MW at the POI without any additional required shunt reactive compensation. The leading plant reactive compensation capacity is sufficient to meet the operating requirement of 0.95 leading at the POI at full output.

GI #503 will be required to control voltage in accordance with a voltage schedule as provided by Idaho Power Grid Operations. GI #503 is required to install a plant controller for managing the real and reactive power output of the 20 MW inverter array at the project 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*.

7.3 Transient Stability Results

Transient stability runs were simulated for 10 seconds to ensure the system is stable and positively damped. The details of the contingencies simulated can be seen in Appendix A-3.0. All faults were simulated as three-phase faults with zero fault impedance.

The following buses were monitored and plotted during the Transient Stability simulation runs:

- [redacted] 345kV
- [redacted] 230kV
- [redacted] 345kV
- [redacted] 120kV
- [redacted] 345kV (POI)

Transient stability evaluation regional criteria used to evaluate the impact of the project can be found in Appendix A-3.1

Under non-stressed conditions on the [redacted] Energy Path, when the [redacted] reactor is most likely switched in, the duration of the voltage raise is not sufficient to result in project tripping due to overvoltage based on exceedance of the NERC PRC-024 high voltage boundary of the required non-trip zone envelope. Under high stressed conditions, when the shunt reactor at [redacted] is not energized, the project may be subject to tripping (by its own protection) due to overvoltage conditions based on the Low/High Voltage Ride Through generator protection (lhvrt) model parameters. Since the lhvrt parameters are compliant with the PRC-024-2 standard, tripping under these conditions is acceptable. The Project can opt to adjust their protection settings to avoid tripping under this scenario.

For all operating conditions studied, which included a tap – single 345kV breaker and a 345kV three breaker ring configuration, transient stability performance for both pre- and post-project cases demonstrated stable and adequately damped response. The contingencies performed under all operating conditions did not result in any WECC/NERC transient voltage dip, voltage duration, or frequency criteria violations.

Transient voltage and frequency plots are provided in Appendix A-3.2.

7.4 Low Voltage and Low Frequency Ride-Through Results

Transient stability was run to test low voltage and frequency ride though by simulating a 24.0 cycle clearing time for a 345kV bus. See Appendix A-3.0 outage number #1 for specific detail. No unit tripping was observed for any of the simulated fault disturbances.

For all operating conditions studied, the transient stability performance for both pre- and post-project cases resulted in stable and adequately damped response. The contingencies performed under all operating conditions did not result in any WECC/NERC transient voltage dip, voltage duration, or frequency criteria violations.

7.5 Post-Transient Stability (Reactive Margin) Results

Post-transient stability analyses were performed for the pre-project and post-project base cases. For post-transient stability, all N-1 outages shall reach a valid power flow solution at a minimum of 105 percent of rated path flow ([redacted]).

The post-transient stability analysis showed valid power flow solutions for all cases and for all the outages. In general, the study showed that the integration of the proposed GI#503 solar PV project did not adversely impact reactive margin for local outages.

7.6 Short Circuit Results

[redacted] generation interconnection projects were assessed.

They are located [redacted], approximately [redacted] on [redacted] 345kV transmission line.

The existing relaying is [redacted], [redacted] utilizing Power Line Carrier (PLC) communication equipment for permissive tripping.

<u>Short Circuit details at approximate interconnect location:</u>

SLG (3I0): 2,016 Amps primary
3PH: 3,527 Amps primary
Thevenin Impedance: 3.77968+j40.4227 (+seq ohms), 14.8488+j109.870 (0seq ohms)

<u>System Protection Configuration Assessments:</u>

1. Tapped – one 3PT[1] breaker at interconnection: Each terminal ([redacted], [redacted] and Interconnection point) would receive relay upgrades (SEL-421/SEL-411L and an additional, dedicated SEL-421 for interconnection). Retain permissive communication assisted tripping. This relies on transfer tripping the GINT for faults within 80% of either terminal.
    - Replace PLC communication equipment at [redacted] & [redacted] with dual (two phase) PLC communication equipment.
    - Add dual (two phase) PLC communication equipment at interconnection.
    - <u>Worst case anticipated clearing time would be approximately 9.5 cycles</u>. This is the clearing time setting for faults occurring beyond the 80% mark from either terminal ([redacted] or [redacted]) to the POI. This is to avoid tripping the remote terminals for faults on the project side of the POI breaker. For faults within 80% distance of either the [redacted] or [redacted] terminals, the approximate clearing time is 3.5 cycles for the terminal closest to the fault and 5.5 cycles for the other remote terminal.

Studies indicate that there is adequate short circuit interrupting capability on breakers in the area for the addition of this generation project. Protective relaying and communications upgrades will be required in adjacent substations.

[1] Three-pole trip

8.0 COST ESTIMATE OF REQUIRED FACILITIES

In Table 2 below is a conceptual-level cost estimate to interconnect GI #503 [redacted] project to Idaho Power's [redacted] 345 kV transmission line. The cost estimate for [redacted] facilities is zero, based on the assumption that GI #502 [redacted] facilities will be adequate for GI #503. Should this project drop out of the queue then the next [redacted] project ahead in the queue will be responsible for the upgrades.

Table 2: Total Conceptual-level Cost Estimate for POI Generation Station Interconnection

Item of Work	Estimate
GI #503 Generation Interconnection POI Station	$0 (1)
GI #503 Generation Station and Remote Stations dual (two phase) PLC	$0 (1)
GI #503 Generation Interconnection Transmission Line	$0 (1)
GI #503 Generation Remote Terminal Relay Replacements	$0 (1)
Total Unloaded Costs	$0
Contingency allowance	$0
Total Loaded Costs	$0

(1) Project GI#503 will use the interconnection facilities constructed for GI#502 – [redacted]

- Note that these estimates do not include the cost of the customer's equipment/facilities or required communication circuits for SCADA, PMU and metering.
- 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 Transmission System Impact Studies.

9.0 CONCLUSIONS

The requested interconnection of the [redacted] project, GI #503, to Idaho Power's system was studied. The project will interconnect using IPC 345kV transmission system.

The results of this study confirm that it is feasible to interconnect the [redacted] project, GI #503, to the existing Idaho Power system. The results from the power flow, Transient, Post-Transient (Reactive Margin), Low Voltage Ride Through and short-circuit analyses confirm that the interconnection of the [redacted] Project will have a negligible impact on the surrounding systems. Issues that occurred in the post-project cases also occurred in the pre-project cases with nearly identical values. Also noted was that GI #503 will meet the power factor requirements required by IPC without any additional required shunt reactive compensation.

All generation projects in the area ahead of this project in the IPCo generation interconnection queue were assessed. There were no additional generation projects that were included in the preliminary power flow analysis to evaluate the interconnection of GI #503. The results and conclusions of this SIS are based on the unique queue/project order.

The total estimated cost to interconnect GI #503 to the IPC system at the 345 kV point of interconnection considered in this study is zero, based on the assumption that GI #502 [redacted] facilities will be adequate for GI #503.

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.

APPENDIX A

A-1.0 Method of Study

The SIS plan inserts the Project up to the maximum requested injection into the selected Western Electric Coordinating Council (WECC) power flow case and then, using Power World 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. For distribution feeder analysis, Idaho Power utilizes Advantica's SynerGEE 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 (VAr) 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 Transient and Post Transient Stability Outages

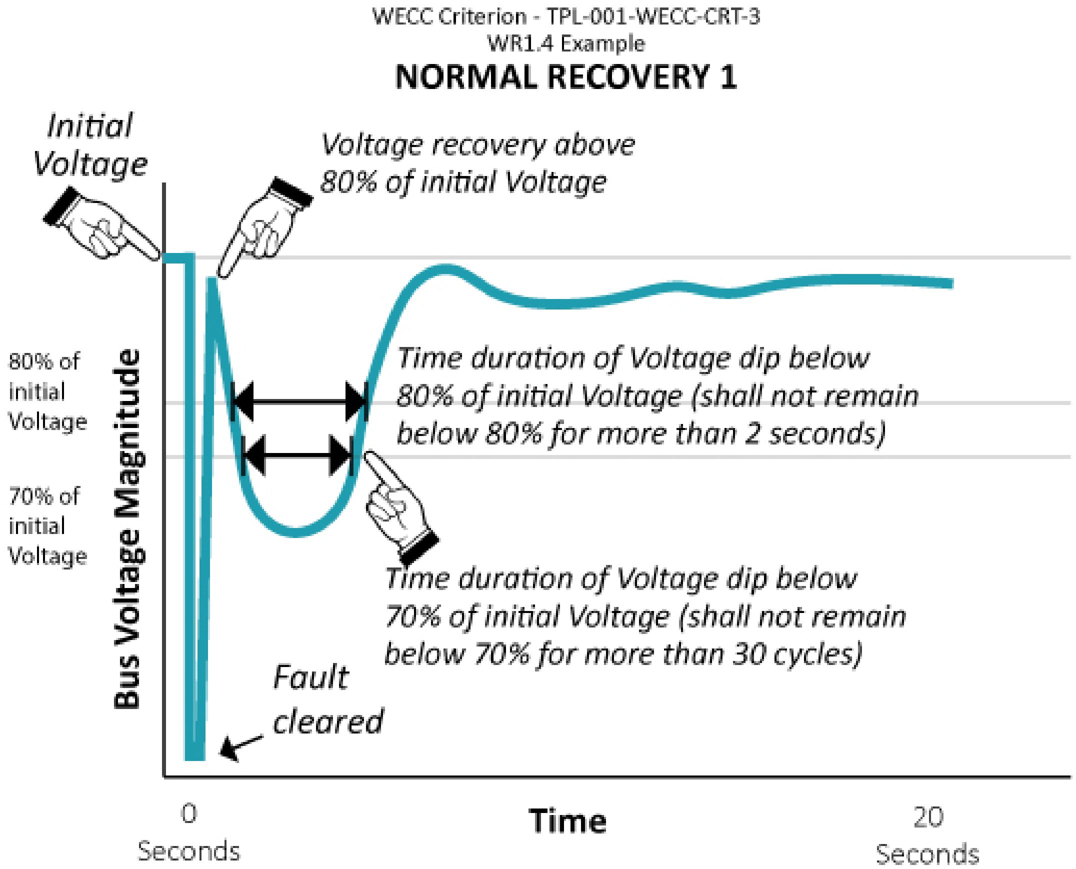
#	Outage ID	PRE and/or POST project (TAP or RING BUS OPTION)	Outage Description
0	00_no_fault.swt	PRE-project POST-project	NO FAULT
1	[redacted]	PRE-project POST-project	[redacted]
2	[redacted]	PRE-project	[redacted]
3	[redacted]	PRE-project	[redacted]
4	[redacted]	POST-project RING BUS OPTION	[redacted]
5	[redacted]	POST-project RING BUS OPTION	[redacted]
6	[redacted]	POST-project TAP OPTION	[redacted]
7	[redacted]	POST-project TAP OPTION	[redacted]
8	[redacted]	POST-project TAP OPTION	[redacted]

A-3.1 Transient Stability Criteria

- All machines in the interconnected system shall remain in synchronism as demonstrated by their relative rotor angles.
- System stability is evaluated based on the damping of the relative rotor angles and the damping of the voltage magnitude swings.
- Transient voltage dip regional business practice: The transient voltage dip must not exceed 25% at load buses or 30% at non-load buses for N-1 contingencies. For N-2 contingencies, the transient voltage dip must not exceed 30% at any bus. The maximum duration of the voltage dip of 20% at load buses must not exceed 20 cycles for any N-1 contingency or 40 cycles for any N-2 contingency.
- Transient frequency regional business practice: N-1 contingency (WECC/NERC Category B) shall not drop below 59.6 Hz; for 6 cycles or more at load bus. For N-2 contingencies (WECC/NERC Category C), shall not drop below 59.0 Hz for 6 cycles or more at load bus.

A summary of the transient stability analysis evaluation regional criteria is provided in the Table and depicted graphically below.

NERC AND WECC CATEGORIES	TRANSIENT VOLTAGE DIP STANDARD	MINIMUM TRANSIENT FREQUENCY STANDARD	POST TRANSIENT VOLTAGE DEVIATION STANDARD
A System Normal	Nothing in addition to NERC		
B One Element Out-of-Service	Not to exceed 25% at load buses or 30% at non-load buses. Not to exceed 20% for more than 20 cycles at load buses.	Not below 59.6Hz for 6 cycles or more at a load bus.	Not to exceed 8% at any bus.
C Two or More Elements Out-of-Service	Not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load buses.	Not below 59.0Hz for 6 cycles or more at a load bus.	Not to exceed 10% at any bus.
D Extreme Multiple-Element Outages	Nothing in addition to NERC		


WECC Criterion - TPL-001-WECC-CRT-3
WR1.4 Example
NORMAL RECOVERY 1
Initial Voltage
Voltage recovery above 80% of initial Voltage
80% of initial Voltage
70% of initial Voltage
Bus Voltage Magnitude
Time duration of Voltage dip below 80% of initial Voltage (shall not remain below 80% for more than 2 seconds)
Time duration of Voltage dip below 70% of initial Voltage (shall not remain below 70% for more than 30 cycles)
Fault cleared
0 Seconds
Time
20 Seconds

[redacted]

A-3.2 Transient Stability Plots

[redacted]

A-4.0 Electrical System Protection Guidance

IPCo requires electrical system protection per <u>Requirements for Generation Interconnections</u> found on the Idaho Power Web site,

http://www.idahopower.com/pdfs/BusinessToBusiness/facilityRequirements.pdf

APPENDIX B. PROJECT LOCATION

[redacted]