System Impact Study Report
Generation Interconnection Request # GI-2016-12

80MW Solar Photovoltaic Facility
Boone 115kV Substation
Pueblo County, Colorado

Transmission Planning West
Xcel Energy
September 26, 2017
(Draft report - pending short circuit analysis)

Executive Summary

The GI-2016-12 ("GI") is an 80MW solar photovoltaic generation facility that will be located in Pueblo County, Colorado. The GI facility will be made up of forty (40) Power Electronics model FS2200-US inverters connected to twenty (20) 4MVA step-up transformers. The GI Customer designated the 115kV bus at the Boone Substation as the Point of Interconnection (POI) – no alternative POI was specified.

The Commercial Operation Date (COD) initially proposed in the Interconnection Request was December 31, 2018. The Feasibility Study was performed and a final report was posted on November 8, 2016. During the system impact study scoping meeting, the customer has changed the COD to November 30, 2019 and backfeed date to October 1, 2019. Even though the Customer's proposed COD changed from December 31, 2018 to November 30, 2019, there are no significant transmission system changes planned between 2018 and 2019 in the study area, so a revision of the steady-state analysis performed in the Feasibility Study is not deemed necessary.

The GI-2016-12 generation interconnection request is for both Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS).

The 80MW output of GI-2016-12 is assumed to be delivered to PSCo native load, so existing PSCo generation is used as its sink.

The following single contingency overload on BHCE facility is attributable to the interconnection of GI-2016-12:

- Portland – Skala 115kV line loading increased from 99.5% to 104.2%

All incremental overloads due to multiple contingencies – whether on transmission facilities in PSCo's System or in an Affected System (i.e. BHCE, CSU and TSGT) – that are attributable to the interconnection of GI-2016-12 will be addressed by system readjustments (including generation curtailment) implemented via operating procedures developed by PSCo prior to commercial operation of the GI-2016-17 interconnection.

The transient stability analysis results indicated that all generating units are stable (remain in synchronism) and display positive damping and the maximum transient voltage dips are within criteria. Based on the results, it was concluded that there is no adverse transient stability impact resulting from the GI-2016-12 interconnection.

Since the Portland – Skala 115kV BHCE line is loaded at its rated capacity (99.5%) in the benchmark case; the GI-2016-12 output for ERIS is 0 MW for the studied generation dispatch scenario. However, higher output may become feasible on an as-available basis depending on the prevailing dispatch of existing PSCo, BHCE, TSGT and CSU generation resources located in the electrical vicinity of GI-2016-12.

Implementing the Network Upgrades needed to mitigate the single contingency thermal overload on the BHCE Portland – Skala 115kV line will allow GI-2016-12 to achieve NRIS of 80MW. The Interconnection Customer will need to work with BHCE to identify the required Network Upgrade.

Therefore, for GI-2016-12,

ERIS = 0 – 80 MW (on an as-available basis)

NRIS = 80 MW (after Network Upgrades needed for Portland – Skala 115kV line overload mitigation are in-service)

The total estimated cost of the recommended system improvements to interconnect the project is approximately **$1.244 million** and includes:

- $ 1.097 million for PSCo-Owned, Customer Funded Transmission Provider Interconnection Facilities
- $ 0.147 million for PSCo Owned; PSCo Funded Network Upgrades for Interconnection
- $ 0 for PSCo Network Upgrades for Delivery

The estimated time to design, procure and construct the Interconnection Facilities is approximately 18 months after authorization to proceed has been obtained.

<u>The cost estimates for BHCE Network Upgrades attributed to GI-2016-12 are not included in this report.</u>

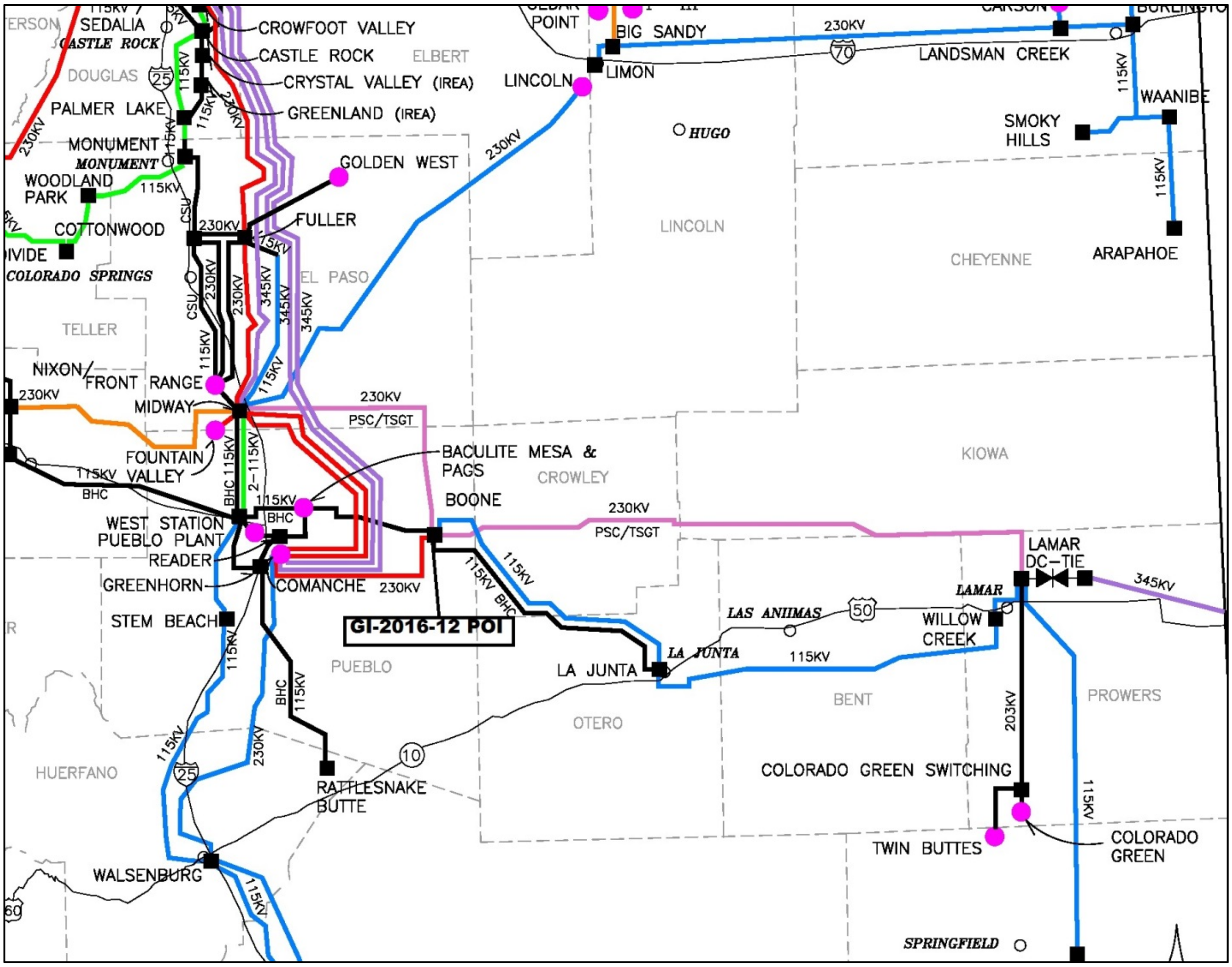

Figure 1 - GI-2016-12 Point of Interconnection and Study Area

Introduction

The GI-2016-12 ("GI") is an 80MW solar photovoltaic generation facility that will be located in Pueblo County, Colorado. The Generation Interconnection (GI) facility will include forty (40) Power Electronics model FS2200-US inverters connected to twenty (20) 4 MVA step-up transformers. The twenty (20) step-up transformers will connect to an 80MVA Main Step-up Transformer which will connect to the Point of Interconnection (POI) using a 115kV Customer owned tie-line. The GI Customer designated the 115kV bus at the Boone Substation as the Point of Interconnection (POI) – no alternative POI was specified.

The Commercial Operation Date (COD) initially proposed in the Interconnection Request was December 31, 2018. The Feasibility Study was performed and a final report was posted on November 8, 2016. During the system impact study scoping meeting, the customer has changed the COD to November 30, 2019 and backfeed date to October 1, 2019. Even though the Customer's proposed COD changed from December 31, 2018 to November 30, 2019, there are no significant transmission system changes planned between 2018 and 2019 in the study area, so a revision of the steady-state analysis performed in the Feasibility Study is not deemed necessary.

The GI-2016-12 generation interconnection request is for both Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS).

The 80MW output of GI-2016-12 is assumed to be delivered to PSCo native load, so existing PSCo generation is used as its sink.

The potential Affected Systems for this GI are Colorado Springs Utilities (CSU), Black Hills Colorado Electric (BHCE) and Tri-State Generation and Transmission Inc. (TSGT).

Study Scope and Analysis Criteria

The scope of this System Impact Study (SIS) includes power flow analysis, transient stability analysis, short circuitand breaker duty analysis, and cost estimates for Interconnection Facilities and identified PSCo Network Upgrades. The SIS includes evaluating GI-2016-12 for both ERIS and NRIS.

The transient stability analysis verifies if the system stability is maintained for faults in the vicinity of the POI. The short circuit analysis determines the maximum available fault current at the POI. In addition, the breaker duty analysis determines if breaker replacements are needed in the neighboring substations due to the fault current contribution from the GI.

Transient stability criteria require that all generating machines remain in synchronism and all power oscillations should be well damped for single contingency events. Also, transient voltage performance should meet the following WECC Transmission System Planning Performance criteria:

- Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 cycles for all contingencies
- For all contingencies, following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds.

- For contingencies without a fault, voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds

Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or non-firm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission system (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as all other Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Power Flow Study Process

The study was performed using the Western Electricity Coordinating Council (WECC) 2022HS1 power flow case released on 09/06/2016. The case was reviewed by CSU, TSGT and BHCE as part of the Colorado Coordinated Planning Group case review process.

The generation dispatch in the WECC base case was adjusted to match the generation dispatch used for feasibility study. The case represented a heavy south to north flow on the Comanche – Midway - Jackson Fuller – Daniels Park transmission system. This was accomplished by adopting the generation dispatch given in Table-9 below. PSCo's generation in zones 700, 704, 709, 710 and 712 is dispatched such that wind generation is at 85% name plate capacity, solar generation is at 80% name plate capacity, conventional non-coal generation is at 90% name plate capacity and, coal generation is dispatched at 100% name plate capacity.

The Lamar DC tie, the Colorado Green and Twin Buttes wind generators are dispatched such that the total combined injection at Lamar 230kV bus is 350MW.

For BHCE, Baculite Mesa units are dispatched at 100% name plate rating and the remaining generation is dispatched at Rattlesnake Wind.

The generation dispatch for CSU loads is provided by CSU.

The GI was studied as a stand-alone project. That is, the study did not include any other Generator Interconnection Requests (GIR) existing in PSCo's or an Affected System's GIR queue, other than the interconnection requests that are considered to be planned resources for which Power Purchase Agreements have been signed.

The GI was modeled using the PSSE modeling data provided by the Interconnection Customer. The modeling data provided by the Interconnection Customer resulted in divergent power flow solution, so the PSSE modeling data provided for feasibility studies is used for the power flow model. PSCo's Fort Saint Vrain #1 unit is used as the sink for the 80MW injection from GI-2016-12.

Transient Stability Study Process

Transient stability analysis was completed on the 2022HS1 case with the proposed new generation dispatched at 100% name plate capacity and using GE's PSLF Ver.21.0_02 program. Three phase faults were simulated for selected single contingencies as part of the analysis using standard clearing events. Bus voltage, bus frequency, and generator angle were recorded and analyzed per the WECC allowable criteria. Also, any generators that went out of synchronism were recorded. WECC's DYTOOLS EPCL program was used to simulate the disturbances. Figure-1 shows the general study area and the POI.

Voltage Regulation and Reactive Power Capability

Interconnection Customers are required to interconnect its Large Generating Facility with Public Service of Colorado's (PSCo) Transmission System in accordance with the *Xcel Energy Interconnection Guidelines for Transmission Interconnected Producer-Owned Generation Greater Than 20 MW* (available at:

http://www.transmission.xcelenergy.com/staticfiles/microsites/Transmission/Files/PDF/Interconnection/Interconnections-POL-TransmissionInterconnectionGuidelineGreat20MW.pdf).

Accordingly, the following voltage regulation and reactive power capability requirements at the POI are applicable to this interconnection request:

- To ensure reliable operation, all Generating Facilities interconnected to the PSCo transmission system are expected to adhere to the *Rocky Mountain Area Voltage Coordination Guidelines (RMAVCG)*. Accordingly, since the POI for this interconnection request is located within Southeast Colorado – Region 4 defined in the *RMAVCG*; the applicable ideal transmission system voltage profile range is 1.02 – 1.03 per unit at regulated buses and 1.0 – 1.03 per unit at non-regulated buses.
- Xcel Energy's OATT (Attachment N effective 10/14/2016) requires all non-synchronous Generator Interconnection (GI) Customers to provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging at the high side of the generator substation. Furthermore, Xcel Energy requires every Generating Facility to have dynamic voltage control capability to assist in maintaining the POI voltage schedule specified by the Transmission Operator as long as the Generating Facility does not have to operate outside its 0.95 lag – 0.95 lead dynamic power factor range capability.
- It is the responsibility of the Interconnection Customer to determine the type (switched shunt capacitors and/or switched shunt reactors, etc.), the size (MVAR), and the locations (34.5 kV or 115 kV bus) of any additional static reactive power compensation needed within the generating plant in order to have adequate reactive capability to meet the +/- 0.95 power factor and the 1.02 – 1.03 per unit voltage range standards at the POI. Further, for wind generating plants to meet the LVRT (Low Voltage Ride Through) performance requirements specified in FERC Order 661-A, an appropriately sized and located dynamic reactive power device (DVAR, SVC, etc.) may

also need to be installed within the generating plant. Finally, it is the responsibility of the Interconnection Customer to compensate their generation tie-line to ensure minimal reactive power flow under no load conditions.

- The Interconnection Customer is required to demonstrate to the satisfaction of PSCo Transmission Operations prior to the commercial in-service date of the generating plant that it can safely and reliably operate within the required power factor and voltage ranges (noted above).

Transient Stability Study Results

The transient stability analysis for the GI-2016-12 System Impact Study simulated the four disturbances for the study case (power flow case with GI-2016-12 modeled). The results of each transient stability run were then analyzed to determine whether the voltage and frequency performed within the WECC criteria and whether generators continued in synchronism before or after the proposed generation was interconnected.

The GI-2016-12 transient stability analysis found no WECC disturbance performance criteria violations for any of the studied contingency events (disturbances). Therefore, it is determined that GI-2016-12 produced no adverse system impact. The following results were obtained for every case and disturbance analyzed:

- ✓ No machines lost synchronism with the system
- ✓ No transient voltage drop violations were observed
- ✓ No transient frequency drop violations were observed
- ✓ Machine rotor angles displayed positive damping

Transient stability plots showing surrounding bus voltages, bus frequencies, generator terminal voltages, generator relative angles, generator speeds, and generator power output for each of the disturbances run for each study scenario have been created and documented in Appendix A.

It is the responsibility of the Interconnection Customer to ensure that its generating facility is capable of meeting the voltage ride-through and frequency ride-through (VRT and FRT) performance specified in the NERC Reliability Standard PRC-024-1.

Summary of Feasibility Study Results

The following single contingency overload on BHCE facility is attributable to the interconnection of GI-2016-12:

- Portland – Skala 115kV line loading increased from 99.5% to 104.2%

The multiple contingency analysis resulted in incremental overloads on the following facilities attributable to the interconnection of GI-2016-12:

- Fountain S – RD_Nixon 115kV line loading increased from 121.5% to 122.9% (CSU line)
- HydePark – West Station 115kV line loading increased from 102.2% to 108.1% (BHCE line)

- Fountain Valley – DesertCove 115kV line loading increased from 126.8% to 136.2% (BHCE line)
- Fountain Valley – MidwayBR 115kV line loading increased from 125.8% to 135.2% (BHCE line)
- Pueblo Plant – Reader 115kV line loading increased from 104.2% to 109.6% (BHCE line)
- Blkfortp – Blksqmv 115kV line loading increased from 173.1% to 175.7% (TSGT line)
- Blksqmv – Fuller 115kV line loading increased from 112.8% to 114.4% (TSGT line)
- Fuller 230/115kV transformer loading increased from 127.9% to 129.0% (TSGT transformer)

All incremental overloads due to multiple contingencies – whether on transmission facilities in PSCo's System or in an Affected System (i.e. BHCE, CSU and TSGT) – will be addressed by system readjustments (including generation curtailment) implemented via operating procedures developed by PSCo prior to commercial operation of the GI-2016-17 interconnection. The Interconnection Customer will need to work with BHCE to identify mitigation for the Portland – Skala 115kV line overload.

Short Circuit Study Results

Will be provided in the final report

Conclusion

Energy Resource Interconnection Service (ERIS): Since the Portland – Skala 115kV BHCE line is loaded at its rated capacity (99.5%) in the benchmark case, GI-2016-12 output for ERIS is 0 MW for the studied generation dispatch scenario. However, higher output may become feasible on an as-available basis depending on the prevailing dispatch of existing PSCo, BHCE and CSU generation resources located in the electrical vicinity of GI-2016-12.

Network Resource Interconnection Service (NRIS): Implementing the Network Upgrades needed to mitigate the single contingency thermal overload on the BHCE Portland – Skala 115kV line will allow GI-2016-12 to achieve NRIS of 80MW. The Interconnection Customer will need to work with BHCE to identify the required Network Upgrade.

Therefore, for GI-2016-12,

ERIS = 0 – 80 MW (on as-available basis)

NRIS = 80 MW (after Network Upgrades needed for Portland – Skala 115kV line overload mitigation are in-service)

Costs Estimates and Assumptions

Scoping level cost estimates for Interconnection Facilities and Network/Infrastructure Upgrades for Interconnection and Delivery (+/- 30% accuracy) were developed by PSCo Engineering. The cost estimates are in 2017 dollars with escalation and contingencies applied. AFUDC is not included. Estimates are based upon typical construction costs for previously performed similar construction. These estimated costs include all applicable labor and overheads associated with the siting support, engineering, design, and construction of these new PSCo facilities. The estimates do not include the cost for any Interconnection Customer owned equipment and associated design and engineering activities. The cost estimates for BHCE Network Upgrades attributed to GI-2016-12 are not included in this report.

The estimated total cost for the required upgrades is **$1.244 milion.**

Figure 2 below is a preliminary one-line of the proposed interconnection. The Point of Interconnection will be the Boone 115kV bus.

The following Tables 2, 3 and 4 list the improvements required to accommodate the interconnection and the delivery of the customer's 80 MW solar facility generation output. The cost responsibilities associated with these facilities shall be handled as per current FERC guidelines. System improvements are subject to revision as a more detailed and refined design is produced.

- Labor is estimated for straight time only – no overtime included.
- Lead times for materials were considered for the schedule.
- The Solar Generation Facility is not in PSCo's retail service territory. Therefore, no costs for retail load metering are included in these estimates.
- PSCo (or it's Contractor) crews will perform all construction, wiring, testing and commissioning for PSCo owned and maintained facilities.
- The estimated time to design, procure and construct the interconnection facilities is approximately 18 months after authorization to proceed has been obtained.
- This project is completely independent of other queued projects and their respective in-service dates.
- A Certificate of Public Convenience and Necessity will not be required for the interconnection facilities construction.
- The Customer will be required to design, procure, install, own, operate and maintain a Load Frequency/Automated Generation Control (LF/AGC) RTU at the Customer Substation. PSCo / Xcel will need indications, readings and data from the LFAGC RTU.
- The GI Customer will string OPGW fiber into the substation as part of the transmission line construction scope.
- Line and substation bus outages will be necessary during the construction period. Outage availability could potentially be problematic and extend requested backfeed date.
- Power Quality Metering will be required on the Customer's 115 kV line terminating into the Boone Substation.

Table 2 – PSCo Owned; Customer Funded Transmission Provider Interconnection Facilities

Element	Description	Cost Est. (Millions)
PSCo's Boone 115kV Transmission Substation	Interconnect Customer to the 115kV bus at the Boone Substation. The new equipment includes: • One (1) 115kV Circuit Breaker • Three (3) motor operated 115kV disconnect switch • Three (3) 115kV combination CT/PT metering units • Power Quality Metering (115kV line from Customer) • Three (3) surge arresters • Two (2) relay panels • Associated bus, wiring and equipment • Associated foundations and structures • Associated transmission line communications, relaying and testing	**$1.047**
	Transmission line tap into substation. Conductor, hardware, and installation labor.	**$0.050**
	Total Cost Estimate for PSCo-Owned, Customer-Funded Interconnection Facilities	**$1.097**
Time Frame	**Design, procure and construct**	**18 Months**

Table 3: PSCo Owned; PSCo Funded Network Upgrades for Interconnection

Element	Description	Cost Est. (Millions)
PSCo's Boone 115kV Transmission Substation	Interconnect Customer to the 115kV bus at the Boone 115kV Substation. The new equipment includes: • Associated communications, supervisory and SCADA equipment • Associated line relaying and testing • Associated bus, miscellaneous electrical equipment, cabling and wiring • Associated foundations and structures • Associated road and site development, fencing and grounding	**$0.147**
	Siting and Land Rights support for substation land acquisition and construction.	**$0.000**
	Total Cost Estimate for PSCo-Owned, PSCo-Funded Interconnection Facilities	**$0.147**
Time Frame	**Site, design, procure and construct**	**18 Months**

Table 4 – PSCo Network Upgrades for Delivery

Element	Description	Cost Est. (Millions)
Element	**Description**	**Cost Est. (Millions)**
	None identified.	**$0.00**
	Total Cost Estimate for PSCo Network Upgrades for Delivery	**$0.00**
	Design, procure and construct	**N/A**
	Total Project Estimate	**$1.244**

Table – 5 - Transient Stability Study Results

Stability Scenarios						
#	Fault Location	Fault Type	Facility Tripped	Clearing Time (cycles)	Post-Fault Voltage Recovery	Angular Stability
1	Boone 230kV	3ph	Boone 230/115kV Xfmr	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
2	Boone 230kV	3ph	Boone – Lamar 230kV	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
3	Midway 230kV	3ph	All Fountain Valley gas units	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
4	Comanche 345 kV	3ph	Trip Comanche#3	Primary (4.0)	Maximum transient voltage dips within criteria	Stable with positive damping

Table 6 – Generation Dispatch in the Study area (MW is Gross Capacity)

PSCo:

Bus	LF ID	MW
Comanche PV	S1	102
Comanche	C1	357
Comanche	C2	365
Comanche	C3	795
Lamar DC Tie	DC	100
Fountain Valley	G1	36
Fountain Valley	G2	36
Fountain Valley	G3	36
Fountain Valley	G4	36
Fountain Valley	G5	36
Fountain Valley	G6	36
Colorado Green	1	64.8
Colorado Green	2	64.8
Twin Butte	1	60
Twin Butte-II	W1	60
Jackson Fuller	W1&W2	199.9
Alamosa CT	G1	15.3
Alamosa CT	G2	12.6
Cogentrix	S3	25.5
Greater Sandhill	S1	16.1
Blanca Peak	S1	19.5
SLV Solar	S1	44.2

BHE:

Bus	LF ID	MW
BUSCHWRTG1	G1	23.0
BUSCHWRTG2	G2	23.0
BUSCHWRTG2	G3	23.0
E Canon	G1	0
PP_MINE	G1	0
PuebloDiesels	G1	0
Pueblo Plant	G1	0
Pueblo Plant	G2	0.0
R.F. Diesels	G1	0.0
Airport Diesels	G1	0.0
Canyon City	C1	0
Canyon City	C1	0
Baculite 1	G1	90
Baculite 2	G1	90
Baculite 3	G1	40.0
Baculite 3	G2	40.0
Baculite 3	S1	21

Baculite 4	G1	40.0
Baculite 4	G2	40.0
Baculite 4	S1	21
Baculite 5	G1	0

CSU:

Bus	LF ID	MW
Birdsale1	1	0.0
Birdsale 2	1	0.0
Birdsale 3	1	0.0
RD_Nixon	1	220.9
Tesla	1	13.2
Drake 5	1	0.0
Drake 6	1	81.6
Drake 7	1	138.2
Nixon CT 1	1	0.0
Nixon CT 2	1	0.0
Front Range CC 1	1	142.6
Front Range CC 2	1	142.6
Front Range CC 3	1	141.9

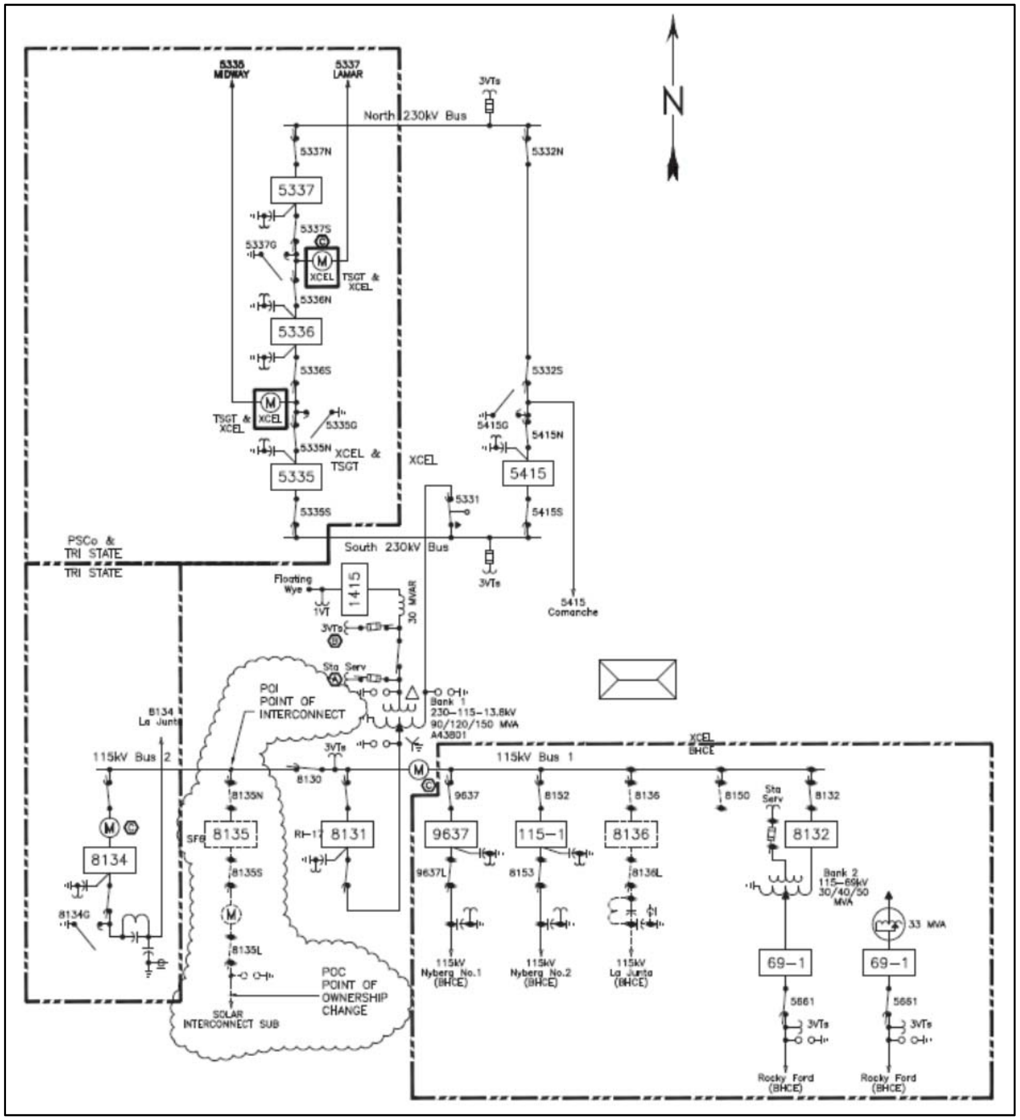

Figure 2 –Preliminary One-Line Diagram of GI-2016-12 Interconnection