DISIS-2020-002

Phase 3 Study Report

06/01/2023

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1.0 Summary

The Phase 3 of the DISIS-2020-002 Definitive Interconnection System Impact Study (DISIS) Cluster has one Generator Interconnection Request (GIR) in the powerflow and stability analysis: GI-2020-13. This Phase 3 Study Report reflects the withdrawal of GI-2020-12, GI-2020-14, and GI-2020-15 from the DISIS-2020-002 Cluster. GI-2020-16 was not withdrawn but did not necessitate power flow and stability restudy since it is in the Northern Colorado study pocket and not impacted by any withdrawal, including GI-2020-15 also in that study pocket. The separate short circuit and breaker duty study outlined in section 4.4.3 of this report excluded the three withdrawn requests and included both GI-2020-13 and GI-2020-16. The cost reduction of network upgrades is a result of breakers no longer identified as overstressed in the short-circuit study results section 4.6.3. A complete description of the system impact restudy is included in this report, whereas only upgrade and cost changes for GI-2020-16 are indicated. GI-2020-13 is a 374 MW_{ac} net rated AC-Coupled Solar Photovoltaic (PV) plus Battery Energy Storage System (BESS) Generating Facility requesting Energy Resource Interconnection Service (ERIS). The requested Point of Interconnection (POI) is a tap on the Boone – Midway 230 kV Line.

GI-2020-13 was studied under the Southern Colorado study pocket.

GI-2020-16 is a 199.5 MW_{ac} net rated solar PV Generating Facility requesting Network Resource Interconnection Service (NRIS). The requested POI is the Barr Lake 230 kV Substation. GI-2020-16 was studied in the Northern Colorado study pocket analysis in Phase 2; restudy of this study pocket was not required.

The Interconnection Service determined for GIRs in this report in and of itself does not convey any transmission service.

1.1 GI-2020-13 Results

The total cost of the upgrades required to interconnect GI-2020-13 on the Boone – Midway 230 kV Line for ERIS is $22.951 million (Table 8, Table 11 and Table 13).

Maximum allowed output of GI-2020-13 without requiring additional Network Upgrades is 0 MW.

ERIS of GI-2020-13 is 374 MW when using the existing firm or non-firm capacity of the Transmission System on an “as available” basis.

1.2 GI-2020-16 Results

The total cost of the required Upgrades for GI-2020-16 to interconnect at the Barr Lake 230 kV Substation is $9.097 Million (Table 9 and Table 12). Network Resource Interconnection Service of GI-2020-16 is 199.5 MW (after required transmission system improvements in Table 9 and Table 12).

2.0 Introduction

The DISIS-2020-002 Definitive Interconnection System Impact Study Cluster Phase 1 Report was completed on 1/3/2021 and Phase 2 of the DISIS-2020-002 Definitive Interconnection System Impact Study report was published on 8/26/2021. Links to both the reports are below:

https://www.rmao.com/public/wtpp/Final_Studies/DISIS-2020-002%20Phase%201%20Report.pdf

https://www.rmao.com/public/wtpp/Final_Studies/2020-Fall-DISIS-PH2-Draft_final.pdf

The Phase 3 of the DISIS-2020-002 Definitive Interconnection Study Cluster consists of one GIR, GI-2020-13, shown in the summary Table 1 below. The total Interconnection Service requested is 374 MW.

GI-2020-13 requested Energy Resource Interconnection Service (ERIS)[1].

Table 1 – Summary of GIRs in DISIS-2020-002

GI#	Resource Type	Interconnection Service	COD	POI	Location	Service Type
GI-2020-13	PV Solar + BESS	374 MW	12/1/2024	Boone-Midway 230 kV Line	Pueblo County, CO	ERIS
GI-2020-16	PV Solar	199.5 MW	10/31/2023	Barr Lake Substation	Adams County, CO	NRIS
Total		573.5 MW				

The approximate geographical locations of the POIs within the Transmission System are shown in Figure 1 below.

[1] 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.

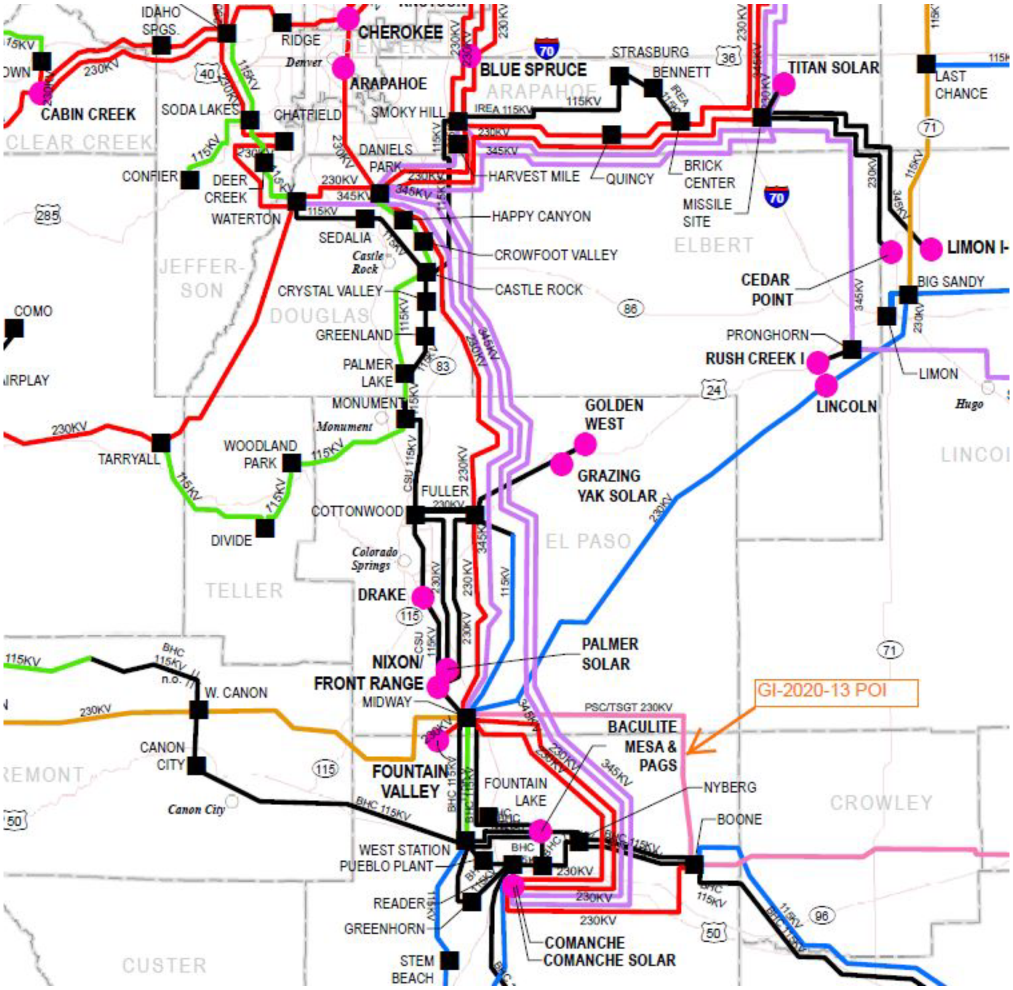

Figure 1 – Approximate Locations of DISIS-2020-002 Generator Interconnection Request POI

3.0 Description of the GIRs

3.1 GI-2020-13

GI-2020-13 is a 250 MW_{ac} Solar PV plus 124 MW_{ac} BESS Generating Facility located in Pueblo County, Colorado. The hybrid facility will be AC-Coupled with the net output at the POI limited to 374 MW_{ac} using a Power Plant Controller. The Solar PV Generating Facility will consist of seventy-four (74) Sungrow SG3600UD 3.6 MVA, ±0.95 PF inverters, each with its own 0.63/34.5 kV, 3.6 MVA Delta/Wye-grounded, Z=8.5% and X/R=10.8 pad-mount transformer. The BESS Generating Facility will consist of thirty-seven (37) Power Electronics FP3510K 3.51 MVA, ±0.95 PF inverters, each with its own 0.66/34.5 kV, 3.5 MVA Delta/Wye-grounded, Z=8.5% and X/R=10.8 pad-mount transformer. The 34.5 kV Collector system of the solar PV and BESS generators will connect to three (3) 99/124/165 MVA, 230/34.5/13.8 kV Wye-grounded/Wye-grounded/Delta, Z=10% and X/R=51 main step-up transformers which will connect to the PSCo transmission system via a 0.5-mile, 230 kV generation tie-line. The POI requested is a tap on the Boone – Midway 230 kV line at approximately 26 miles from the Midway 230 kV Substation.

The BESS has a maximum and minimum state of charge of 100% and 5%, respectively.

The interconnection at the tap point will require building a new switching station is referred to as “GI-2020-13 230 kV Switching Station” in this report.

The proposed COD of GI-2020-13 is December 1, 2024. For the study purpose, the back-feed date is assumed to be June 1, 2024, approximately six (6) months before the COD.

3.2 GI-2020-16

GI-2020-16 is a 199.5 MWac net rated solar PV Generating Facility located in Adams County, Colorado. The solar PV Generation Facility will consist of fifty-nine (59) SMA Sunny Central SC4400 UP-US 4.40 MVA/3.52 MW ±0.80 PF inverters, each with its own 0.66/34.5 kV, 4.40 MVA Wye-Grounded/Delta Z=6.5%, X/R=8.58 pad-mount transformer. The 34.5kV collector system will connect to one (1) 134/178/222 MVA, 34.5/230/13.8 kV Wye-grounded/Wye-grounded/Delta, Z=11.5%, X/R=34.52 main step-up transformer which will connect to the PSCo transmission system via a 0.13-mile, 230 kV generation tie-line. The POI is the Barr Lake 230 kV substation. The proposed COD of GI-2020-16 is October 31, 2023. For the study purpose, the back-feed date is assumed to be June 1, 2023, approximately six (6) months before the COD.

4.0 Study Scope

Phase 3 of the Definitive Interconnection System Impact Study (DISIS) scope consists of:

a. Power flow/voltage analysis,
b. Stability analysis and short-circuit analysis,
c. Non-binding cost estimates for the Transmission Provider's Interconnection Facilities, Station Network Upgrades and System Network Upgrades required to reliably interconnect the GIR(s),
d. Each Interconnection Customer's assigned costs based on the total non-binding cost estimates determined above, and
e. Identification of Contingent Facilities applicable to each GIR.

Since the completion of the Phase 2 study report on 8/26/2021, the following changes made it necessary to update the relevant power flow analyses in the Phase 3 study.

1. Withdrawal of GI-2020-12, GI-2020-14, and GI-2020-15. The withdrawal of GI-2020-12 and GI-2020-14 impacted the South Pocket and as a result the South Pocket was restudied in the Phase 3 study report. The withdrawal of GI-2020-15 in the North Pocket did not impact the North Pocket as no System Network Upgrades corresponding to the withdrawn GI were found in its analysis.

4.1 Study Pockets

As shown in Figure 1,

- GI-2020-13 is in the Southern Colorado study pocket.

The study pocket analysis only modeled the GIR with a POI in that study pocket.

4.2 Study Areas

The study area for the Southern Colorado study pocket includes the WECC base case zones 704, 710, 712, 751, 757, and 785. The potential Affected Systems in the analysis are Western Area Power Administration (WAPA), Black Hills Energy (BHE), Colorado Springs Utilities (CSU), and Tri-State G&T (TSGT) transmission systems in the study area.

4.3 Study Criteria

The following steady-state analysis criteria is used to identify violations on the PSCo system and the Affected Systems:

P0 - System Intact conditions:

Thermal Loading: ≤ 100% of the normal facility rating
Voltage range: 0.95 to 1.05 per unit

P1 & P2-1 – Single Contingencies:

Thermal Loading: ≤ 100% normal facility rating
Voltage range: 0.90 to 1.10 per unit
Voltage deviation: ≤ 8% of pre-contingency voltage

P2 (except P2-1), P4, P5 & P7 – Multiple Contingencies:

Thermal Loading: ≤ 100% emergency facility rating
Voltage range: 0.90 to 1.10 per unit
Voltage deviation: ≤ 8% of pre-contingency voltage.

The following criteria is used for the reliability analysis of the PSCo system and Affected Systems.

The transient voltage stability criteria are as follows:

a. Following fault clearing, voltage shall recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event for all P1 through P7 events for each applicable Bulk Electric System (BES) bus serving load.
b. 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 all P1 through P7 events.
c. For contingencies without a fault (P2.1 category event), 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.
d. Note generator bus frequency plots are included, however, PSCo does not have criteria for frequency events.

The transient angular stability criteria are as follows:

a. P1 – No generating unit shall pull out of synchronism. A generator being disconnected from the system by fault clearing action or by a special Protection System is not considered an angular instability.
b. P2-P7 – One or more generators may pull out of synchronism, provided the resulting apparent impedance swings shall not result in the tripping of any other

generation facilities.

c. P1-P7 – The relative rotor angle (power) oscillations are characterized by positive damping (i.e., amplitude reduction of successive peaks) > 5% within 30 seconds.

The breaker duty analysis criterion is fault current after GIR(s) addition shall not exceed 100% of the breaker duty rating.

4.4 Study Methodology

4.4.1 Steady-State Assessment Methodology

The steady-state power flow assessment is performed using the PowerGEM TARA software. The generation redispatch for ERIS is identified using TARA's Security Constrained Redispatch (SCRD) tool.

Thermal violations are identified if a facility (i) resulted in a thermal loading >100% in the Study Case after the study pocket GIR cluster addition and (ii) contributed to an incremental loading increase of 1% or more to the benchmark case loading.

Voltage violations are identified if a bus (i) resulted in a bus voltage >1.1 p.u. (or <0.9 p.u.) in the Study Case after the study pocket GIR cluster addition and (ii) contributed to an adverse impact of +0.005 p.u. (or -0.005 p.u.) compared to the Benchmark Case voltage.

Distribution Factor(s) (DFAX) criteria for identifying contribution to thermal overloads is ≥1%. DFAX criteria for identifying contribution to the voltage violations is 0.005 p.u.

When the study pocket has a mix of NRIS and ERIS requests, it is studied by first modeling the NRIS GIRs at their full requested amount and modeling the ERIS GIRs offline. Network Upgrades required to mitigate the thermal and/or voltage violations are only allocated to NRIS requests because other GIR's output is modeled at zero.

The NRIS GIRs and their associated Network Upgrades are then modeled in the NRIS Study Case, and ERIS GIRs are dispatched at 100% to study the system impact. Violations are identified and the study evaluates if a generation redispatch combination eliminates the violation. If generation redispatch is unable to eliminate the violation, upgrades will be identified.

The resources included in the Optimal Power Flow (OPF) redispatch are:

1. All PSCo and Non-PSCo resources connected to the PSCo Transmission System.
2. Higher-queued NRIS generation in the PSCo queue.

3. Generation connected to an Affected System Transmission System if that generation is a designated network resource to serve load connected to PSCo.
4. All other generation connected to an Affected System Transmission System and Stressed in the Study Case may be dispatched to the Base Case level.

Maximum allowable ERIS generation is calculated for each GIR using its DFAX for overloads identified at full output, such that all identified overloads are eliminated.

4.4.2 Transient Stability Study Methodology

All generators in the study pocket shall meet the transient stability criteria. If any violations are found, the contributing GIR(s) will be identified for performance violations and mitigations will be attributed to the contributing generator(s). The stability analysis is conducted by performing select single and multiple contingencies in the study pocket.

4.4.3 Short-Circuit and Breaker-Duty Study Methodology

The study was performed using the short-circuit model maintained for the PSCo owned system. This model includes only a small portion of Affected System(s) at the seams, and breaker duty on Affected System(s) was not evaluated in this study. The Affected Systems may choose to perform their own study to identify potential for breaker duty violations on their system.

A Benchmark Case aligned with the Phase 1 Base Case was developed using Siemens PSS®CAPE short-circuit analysis software (CAPE) which included both higher-queued ERIS and NRIS GIRs modeled at full output. The Study Case in CAPE was created from the Benchmark Case by modeling all NRIS and ERIS GIRs in the DISIS-2020-002 Cluster, and their associated Network Upgrades identified in the Phase 1 report. Facility rating upgrades to existing lines were neglected for short-circuit studies.

GIRs are modeled on a per-machine basis, using the impedance and configuration information provided in the Interconnection Request. If tie-line length was not specified, gen-tie lines were assumed to have a length of 0.25 miles, with estimated impedance appropriate for the voltage. All inverter-based generation, including generator step-up transformers, were modeled on an aggregate basis using appropriately scaled generic models at the low side of the main power transformer(s).

All generating facilities, regardless of NRIS or ERIS, were modeled on-line at rated capacity and assumed capable of producing maximum fault current. Hybrid generating facilities (e.g., solar with battery storage) were modeled with each technology modeled as a separate generating resource at its rated capacity, regardless of any limitations to the combined output imposed otherwise.

Short-circuit current and equivalent system impedances were obtained for both the Benchmark Case and the Study Case from CAPE for three-phase and single-line-to-ground faults at each POI for GIR in the DISIS-2020-002 Cluster.

Breaker duty studies are performed for the Benchmark Case for the entire system. Circuit breakers identified as overstressed (0% margin) in the Benchmark Case study are not included in the analysis. However, these are identified as Contingent Facilities to the DISIS-2020-002 GIRs if there is an increase in fault current contribution to these breakers from the Study Case evaluation.

Breaker duty studies are conducted using a sub-transient fault analysis. Single and three-phase faults are placed at each substation in the system. Each breaker is modeled by the manufacturer and model number with the catalog characteristics for that breaker and its application, i.e., the relevant standard applying to that breaker's date of manufacture, kA interrupting rating, voltage rating, relay operate time, breaker interrupting time, proximity to generation, etc. The reclosing scheme is not considered in the analysis. The aforementioned factors are used to calculate an XR factor according to ANSI C37.010-1999, ANSI C37.5-1979, or C37.6-1971. For evaluation of breaker opening by C37.010-1999, applicable to all breakers identified in this study, and with no reclosing and no additional derating, the equivalent current the breaker is required to interrupt is simply the fault current multiplied by the XR factor ($I_{breaking}$). This is compared against that breaker's rated interrupting capacity to determine whether the breaker is overstressed. If it is greater than the breaker's interrupting capacity, it is considered to be overstressed (0% margin).

Breaker duty studies are re-performed while excluding each individual interconnection and corresponding network upgrade, one at a time. Fault currents at the location of each identified overdutied breaker are compared to determine the relative contribution of each interconnection and corresponding network upgrade.

Then, cost allocation is determined as follows:

$$Allocation\% = \frac{Fault\ Current\ Reduction\ due\ to\ Removal\ of\ GI\ of\ interest}{\sum Fault\ Current\ Reduction, All\ GIs} * 100$$

Where,

$$Fault\ Current\ Reduction = (Fault\ Current\ at\ Breaker, All\ GIs\ connected\ ) - (Fault\ Current\ at\ Breaker, All\ GIs\ connected\ except\ GI\ of\ interest)$$

And,

the Fault Type matches the fault type (3-phase or phase-to-ground) causing the breaker to be overstressed.

Figure 2 – Cost Allocation Calculation

4.5 Study Analyses

The Phase 3 study needed an updated steady-state analyses for only the Southern Colorado due to the withdrawal of GI-2020-12 and GI-2020-14 in the Southern Colorado study pocket. The withdrawal of GI-2020-15 in the North Pocket did not impact the Northern Colorado study pockets as no System Network Upgrades corresponding to the GI were found in its analysis.

Steady-state power flow analyses were performed using PowerGEM TARA software. The generation redispatch for ERIS is identified using TARA.

Short-circuit analyses in Phase 3 studies were performed using Siemens PSS®CAPE short-circuit analysis software (CAPE). Facility rating upgrades to existing lines were neglected for short-circuit analyses. Short-circuit current and equivalent system impedances were obtained for both the Benchmark Case and the Study Case from CAPE for three-phase and single-line-to-ground faults at the POI for GIR in the DISIS-2020-002 Cluster.

Transient stability analyses in Phase 3 studies were performed using a transient stability Study Case developed in GE PSLF corresponding to the steady-state PSLF Study Case.

Select P1 disturbance events were simulated in Phase 3 stability analyses. The P1 disturbance events are simulated using three-phase bolted faults.

4.6 Southern Colorado Study Pocket Analysis

The Study Case modeled GI-2020-13 tapping to the Boone - Midway 230 kV Line. The Phase 3 study report consists of an updated steady-state power flow analysis, transient stability, and short-circuit analysis due to the withdrawal of GI-2020-12 and GI-2020-14 in the south pocket.

4.6.1 Steady-State Analysis

The Benchmark Case and Study Case created for the Phase 3 study were started from the latest available base case created for the Spring 2022 DISIS. Based on GIs withdrawn, a Phase 3 restudy is required consisting of steady-state Analysis, Transient Stability and Short-Circuit analysis in the south study pocket. The System Network Upgrades and future queue projects modeled in the south were removed from the Fall 2021 DISIS cluster, Spring 2021 DISIS cluster, and Fall 2020 DISIS cluster and the resultant Benchmark Case was created for the steady-state Analysis. The ERIS Study case was created from the Benchmark case with GI-2020-13 tapped on the Boone - Midway 230 kV line. As stated in the Phase 1 report, the multiple contingency analysis is conducted for informational purposes only and overloads are mitigated using system adjustments, including generation redispatch and/or operator actions. The Phase 3 restudy of the power flow analysis included single as well as system intact contingency analysis.

ERIS Steady-State Analysis:

There were no NRIS GIRs in the Southern Colorado study pocket. Therefore, the ERIS Study Case was developed from Benchmark Case by making the following modifications:

- GI-2020-13 is modeled tapping to the Boone – Midway 230 kV Line and dispatched at 100%.
- ERIS output of GI-2020-13 was balanced by reducing all PSCo and non-PSCo generation outside the study pocket on a pro-rata basis.

The results of the system intact analysis for the ERIS Study Case are given in Table 2.

The results of the single contingency analysis for the ERIS Study Case are given in Table 3.

The ERIS Study Case contingency analysis was performed using OPF to redispatch and alleviate any single and system intact overloads according to Section 4.4.1. Table 4 shows the single overloads which cannot be mitigated by redispatch using OPF. This indicates the need for required System Network Upgrades for ERIS GIRs, tabulated in Table 5.

Table 2 – Southern Colorado Study Pocket ERIS Study Overloads Identified in System Intact Analysis

Overloaded Facility	Type	Owner	Facility Normal Rating (MVA)	Facility Loading in ERIS Benchmark Case		Facility Loading in ERIS Study Case		Loading % Change Due to Study Pocket GIRs	Single Contingency Definition
				MVA Flow	% Loading	MVA Flow	% Loading		
DANIELPK (70139) TO PRAIRIE1 (70331) 230 kV CKT #1	Line	PSCo	478.00	479.86	100.39	507.83	106.24	5.85	System Intact Condition
VOLLMERT (72413) TO FULLER (73481) 115 kV CKT #1	Line	TSGT	143.00	133.89	93.63	147.78	103.34	9.71	System Intact Condition

Table 3 – Southern Colorado Study Pocket ERIS Study Overloads Identified in Single Contingency Analysis

Overloaded Facility	Type	Owner	Facility Normal Rating (MVA)	Facility Loading in ERIS Benchmark Case		Facility Loading in ERIS Study Case		Loading % Change Due to Study Pocket GIRs	Single Contingency Definition
				MVA Flow	% Loading	MVA Flow	% Loading		
DANIELPK (70139) TO PRAIRIE1 (70331) 230 kV CKT #1	Line	PSCo	478.00	705.38	147.57	746.78	156.23	8.66	DANIELPK (70139) TO PRAIRIE3 (70323) 230 kV CKT #2
GREENWD (70212) TO PRAIRIE3 (70323) 230 kV CKT #1	Line	PSCo	484.00	646.14	133.5	687.47	142.04	8.54	DANIELPK (70139) TO PRAIRIE1 (70331) 230 kV CKT #1
VOLLMERT (72413) TO FULLER (73481) 115 kV CKT #1	Line	WAPA	143.00	169.10	118.25	191.23	133.73	15.48	SGL_230_025
DANIELPK (70601) TO COMANCHE (70654) 345 kV CKT #1	Line	PSCo	1183.00	1424.45	120.41	1578.71	133.45	13.04	DANIELPK (70601) TO TUNDRA (70653) 345 kV CKT #2
VOLLMERT (72413) TO BLK SQMV (73460) 115 kV CKT #1	Line	TSGT	173.00	164.22	94.92	186.30	107.69	15.44	SGL_230_025
DANIELPK (70139) TO PRAIRIE3 (70323) 230 kV CKT #2	Line	PSCo	571.00	698.10	122.26	739.56	129.52	7.26	DANIELPK (70139) TO PRAIRIE1 (70331) 230 kV CKT #1
CTTNWD N (78658) TO KETTLECK S (78673) 115 kV CKT #1	Line	PSCo	162.00	196.20	121.11	205.25	126.7	5.59	BRIARGATE N (78656) TO BRIARGATE S (78657) 115 kV CKT #1
DANIELPK (70139) TO FULLER (78854) 230 kV CKT #1	Line	PSCo	478.00	505.44	105.74	603.91	126.34	20.6	DANIELPK (70601) TO COMANCHE (70654) 345 kV CKT #1
FTN_VLY (70193) TO MIDWAYBR (73412) 115 kV CKT #1	Line	PSCO/ WAPA	171.00	195.45	114.3	209.77	122.67	8.37	DANIELPK (70601) TO COMANCHE (70654) 345 kV CKT #1

Overloaded Facility	Type	Owner	Facility Normal Rating (MVA)	Facility Loading in ERIS Benchmark Case		Facility Loading in ERIS Study Case		Loading % Change Due to Study Pocket GIRs	Single Contingency Definition
				MVA Flow	% Loading	MVA Flow	% Loading		
MONACO12 (70481) TO SULLIVN2 (70365) 230 kV CKT #1	Line	PSCo	445.00	526.75	118.37	536.36	120.53	2.16	BUCKLEY2 (70046) TO TOLGATE (70491) 230 kV CKT #1
GREENWD (70212) TO MONACO12 (70481) 230 kV CKT #1	Line	PSCo	484.00	563.33	116.39	573.10	118.41	2.02	BUCKLEY2 (70046) TO TOLGATE (70491) 230 kV CKT #1
CANONCTY (70085) TO NCANON_W (70294) 69 kV CKT #1	Line	PSCo	23.00	26.72	116.18	27.22	118.33	2.15	NCANON_W (70294) TO HOGBACK69 (71026) 69 kV CKT #2
GREENWD (70212) TO PRAIRIE1 (70331) 230 kV CKT #2	Line	PSCo	572.00	628.46	109.87	670.04	117.14	7.27	DANIELPK (70139) TO PRAIRIE3 (70323) 230 kV CKT #2
GI-2020-13 P (990051) TO MIDWAYPS (70286) 230 kV CKT #1	Line	PSCo	319.00	159.53	50.01	373.58	117.11	67.1	DANIELPK (70601) TO COMANCHE (70654) 345 kV CKT #1
BOONE (70061) TO GI-2020-13 P (990051) 230 kV CKT #1	Line	PSCo	319.00	13.05	4.09	368.25	115.44	111.35	GI-2020-13 P (990051) TO MIDWAYPS (70286) 230 kV CKT #1
COMANCHE (70122) TO COMANCHE (70654) 230/345 kV CKT #T4	Xfmr	PSCo	560.00	497.45	88.83	635.15	113.42	24.59	COMANCHE (70122) TO COMANCHE (70654) 230/345 kV CKT #T3
COMANCHE (70122) TO COMANCHE (70654) 230/345 kV CKT #T3	Xfmr	PSCo	560.00	497.45	88.83	635.15	113.42	24.59	COMANCHE (70122) TO COMANCHE (70654) 230/345 kV CKT #T4
DANIELPK (70139) TO DANIELPK (70601) 230/345 kV CKT #T5	Xfmr	PSCo	560.00	606.03	108.22	613.03	109.47	1.25	DANIELPK (70139) TO DANIELPK (70601) 230/345 kV CKT #T3
DANIELPK (70139) TO DANIELPK (70601) 230/345 kV CKT #T4	Xfmr	PSCo	560.00	606.03	108.22	613.03	109.47	1.25	DANIELPK (70139) TO DANIELPK (70601) 230/345 kV CKT #T5
DANIELPK (70139) TO DANIELPK (70601) 230/345 kV CKT #T3	Xfmr	PSCo	560.00	606.03	108.22	613.03	109.47	1.25	DANIELPK (70139) TO DANIELPK (70601) 230/345 kV CKT #T5
LEETSDAL (70260) TO SULLIVN2 (70365) 230 kV CKT #1	Line	PSCo	426.00	451.18	105.91	460.85	108.18	2.27	BUCKLEY2 (70046) TO TOLGATE (70491) 230 kV CKT #1
DESRTCOV (70449) TO W.STATON (70456) 115 kV CKT #1	Line	PSCo	222.00	224.58	101.16	239.36	107.82	6.66	DANIELPK (70601) TO COMANCHE (70654) 345 kV CKT #1
LAMAR_CO (70254) TO LAMAR_C2 (70255) 230 kV CKT #1	Line	PSCo	239.00	227.89	95.35	253.10	105.9	10.55	DANIELPK (70601) TO COMANCHE (70654) 345 kV CKT #1
DRAKE N (78661) TO DRAKE S (78662) 115 kV CKT #1	Xfmr	PSCo	171.00	172.71	101	179.29	104.85	3.85	KELKER E (78670) TO SANTA FE S (78680) 115 kV CKT #2
MIDWAYPS (70286) TO MIDWAYPS (70465) 230/345 kV CKT #T3	Xfmr	PSCo	560.00	502.21	89.68	577.47	103.12	13.44	DANIELPK (70601) TO COMANCHE (70654) 345 kV CKT #1

Overloaded Facility	Type	Owner	Facility Normal Rating (MVA)	Facility Loading in ERIS Benchmark Case		Facility Loading in ERIS Study Case		Loading % Change Due to Study Pocket GIRs	Single Contingency Definition
				MVA Flow	% Loading	MVA Flow	% Loading		
WATERTON (70464) TO WATERTON (70466) 230/345 kV CKT #T3	Xfmr	PSCo	560.00	495.88	88.55	572.38	102.21	13.66	DANIELPK (70601) TO COMANCHE (70654) 345 kV CKT #1
MIDWAYPS (70286) TO MIDWAYPS (70465) 230/345 kV CKT #T3	Xfmr	PSCo	560.00	497.90	88.91	569.97	101.78	12.87	DANIELPK (70601) TO COMANCHE (70654) 345 kV CKT #1
PUEBPLNT (70339) TO READER (70352) 115 kV CKT #1	Line	PSCo	160.00	155.41	97.13	161.22	100.76	3.63	DANIELPK (70601) TO COMANCHE (70654) 345 kV CKT #1
WATERTON (70464) TO WATERTON (70466) 230/345 kV CKT #T3	Xfmr	PSCo	560.00	490.78	87.64	562.63	100.47	12.83	DANIELPK (70601) TO COMANCHE (70654) 345 kV CKT #1
DANIELPK (70601) TO TUNDRA (70653) 345 kV CKT #2	Line	PSCo	1183.00	1061.51	89.73	1184.42	100.12	10.39	DANIELPK (70601) TO COMANCHE (70654) 345 kV CKT #1
LEETSDAL (70260) TO MONROEPS (70291) 230 kV CKT #1	Line	PSCo	311.00	304.90	98.04	311.19	100.06	2.02	GREENWD (70212) TO ARAPAHOE (70038) 230 kV CKT #1

Table 4 – Southern Colorado Study Pocket ERIS Study Overloads (After Redispatch) Identified in Single Contingency Analysis

Overloaded Facility	Type	Owner	Facility Normal Rating (MVA)	Facility Loading in ERIS Benchmark Case		Facility Loading in ERIS Study Case (After Redispatch)		Loading % Change Due to Study Pocket GIRs	Single Contingency Definition
				MVA Flow	% Loading	MVA Flow	% Loading		
BOONE (70061) TO GI-2020-13 P (990051) 230 kV CKT #1	Line	PSCo	319.00	368.25	115.44	366.75	114.97	-0.47	GI-2020-13 P (990051) TO MIDWAYPS (70286) 230 kV CKT #1
GI-2020-13 P (990051) TO MIDWAYPS (70286) 230 kV CKT #1	Line	PSCo	319.00	367.87	115.32	365.13	114.46	-0.86	BOONE (70061) TO GI-2020-13 P (990051) 230 kV CKT #1
CTTNWD N (78658) TO KETTLECK S (78673) 115 kV CKT #1	Line	CSU	162.00	205.24	126.69	178.3	110.06	-16.63	BRIARGATE N (78656) TO BRIARGATE S (78657) 115 kV CKT #1

Table 5 – Southern Colorado Study Pocket ERIS – System Network Upgrades

Network Upgrade	Type	Existing Normal Rating (MVA)	Max Overload on Existing Normal Rating (%)	Minimum Normal Rating Required (MVA)
BOONE (70061) TO GI-2020-13 P (990051) 230 kV CKT #1	Line	319.00	115.00	366.80
GI-2020-13 P (990051) TO MIDWAYPS (70286) 230 kV CKT #1	Line	319.00	114.50	365.10
CTTNWD N (78658) TO KETTLECK S (78673) 115 kV CKT #1	Line	162.00	110.10	178.30

The maximum output of the ERIS GIRs without requiring additional Network Upgrades are:

- ERIS of GI-2020-13 is 0 MW.

The Phase 3 report identified CSU as an impact to Affected System in steady-state Single Contingency Overloads with redispatch.

4.6.2 Transient Stability Analysis

The transient stability analysis was performed in the south pocket using the generation redispatch scenario determined by VERDA in the Phase 3 steady-state study. Table 6 is a summary of the contingencies studied and the corresponding stability results.

The following results were obtained for the disturbances analysis:

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

The transient stability plots are shown in Section 9.0 of this report.

Table 6 – Southern Colorado Transient Stability Analysis Results

Ref. No.	Fault Location	Fault Category	Fault type	Facility Tripped	Clearing Time (cycles)	Post-Fault Voltage Recovery	Angular Stability
1	Lamar County 230 kV	P2	3 Ph	Lamar – Boone 230kV line and all generation at Lamar	5	Stable	Stable
2	Boone 230 kV	P2	3 Ph	Lamar – Boone 230kV line and all generation at Lamar	5	Stable	Stable
3	Boone 230 kV	P1	3 Ph	Boone – GI-2020-3POI - Comanche 230 kV	5	Stable	Stable
4	GI-2020-13 POI	P1	3 Ph	GI-2020-13 POI - Midway 230 kV Line	5	Stable	Stable
5	GI-2020-13 POI	P1	3 Ph	GI-2020-13 POI - Boone 230 kV Line	5	Stable	Stable
6	Comanche 345 kV	P1	3 Ph	Comanche#3 generator	4	Stable	Stable
7	Midway 230 kV	P1	3 Ph	All Fountain Valley gas units	5	Stable	Stable
8	Midway 230 kV	P1	3 Ph	Midway – Fuller 230kV, MidwayBR 230kV Lines	5	Stable	Stable
9	Midway 345 kV	P1	3 Ph	MidwayPS – Waterton 345kV line & Midway 230/345kV xfmr	4	Stable	Stable

The study did not identify any impacts to Affected Systems.

4.6.3 Short-Circuit Analysis Results

There were no breakers identified requiring upgrades as a result of a short-circuit analysis performed by Xcel Energy System Protection Engineering.

4.6.4 Summary of Southern Colorado Study Pocket Analysis

The ERIS study showed single contingency overloads that cannot be alleviated by performing OPF redispatch. Hence, it is identified there are additional network upgrades needed for ERIS requested.

A DFAX analysis with respect to thermal overloads was performed to compute the maximum allowable output for the ERIS GIR.

The maximum allowed output of the ERIS GIRs without requiring additional Network Upgrades is:

- GI-2020-13: 0 MW

ERIS, when using the existing firm or non-firm capacity of the Transmission System on an "as available" basis is:

- GI-2020-13: 374 MW

The Phase 3 report identified WAPA as an impact to Affected System in steady-state Single Contingency Overloads.

5.0 Cost Estimates and Assumptions

There are three types of costs identified in the study:

- Transmission Provider's Interconnection Facilities directly assigned to each GIR.
- Station Network Upgrades, allocated to each GIR connecting to that station on a per-capita basis per Section 4.2.4(a) of the LGIP.
- All other Network Upgrades allocated by the proportional impact per Section 4.2.4(b) of the LGIP.

5.1 Total Cost of Transmission Provider's Interconnection Facilities (TPIF)

The total cost of Transmission Provider's Interconnection Facilities (TPIF) for each POI and each GIRs cost assignment are given in Table 7.

Table 7 – Total Cost of Transmission Provider's Interconnection Facilities by GIR

GIR	POI	Total Cost (million)
GI-2020-13	Boone - Midway 230 kV Line	$1.262
GI-2020-16	Barr Lake 230 kV Substation	$1.480

Table 8 specifies GI-2020-13 Transmission Provider's Interconnection Facilities and the corresponding costs.

Table 8 – GI-2020-13 Transmission Provider's Interconnection Facilities

Element	Description	Cost Est. (million)
PSCo's GI-2020-13 230kV Switching Station	Interconnection Customer to tap at the Boone - Midway 230 kV line. The new equipment includes: • (3) 230 kV deadend structures • (3) 230 kV surge arresters • (1) 230 kV 3000A disconnect switch • (3) CCVTs • (3) CTs • Fiber communication equipment • Station controls • Associated electrical equipment, bus, wiring and grounding • Associated foundations and structures • Associated transmission line communications, fiber, relaying and testing	$1.162
	Siting and Land Rights support for siting studies, land and ROW acquisition and construction	$0.100
Total Cost Estimate for Interconnection Customer-Funded, PSCo-Owned Interconnection Facilities		**$1.262**
Time Frame	**Site, design, procure and construct**	**36 Months**

Table 9 specifies GI-2020-16 Transmission Provider's Interconnection Facilities and the corresponding costs.

Table 9 – GI-2020-16 Transmission Provider's Interconnection Facilities

Element	Description	Cost Est. (million)
PSCo's Barr Lake 230 kV Substation	Interconnection GI-2020-16 at the Barr Lake 230 kV line Substation. The new equipment includes: • (1) 230 kV deadend structure • (3) 230 kV surge arresters • (1) 230 kV 3,000 A disconnect switch • (3) CTs • (3) PTs • Fiber communication equipment • Station controls • Associated electrical equipment, bus, wiring and grounding • Associated foundations and structures • Associated transmission line communications, fiber, relaying and testing.	$1.380
	Siting and Land Rights support for siting studies, land and ROW acquisition and construction	$0.100
Total Cost Estimate for Interconnection Customer-Funded, PSCo-Owned Interconnection Facilities		**$1.480**
Time Frame	**Site, design, procure and construct**	**36 Months**

5.2 Total Cost of Station Network Upgrades

The total cost of Station Network Upgrades for the POI and the GIR cost assignment are given in Table 9.

Table 10 – Total Cost of Station Network Upgrades by POI

POI	Total Cost (million)	GIRs Sharing the POI	Allocation
Boone – Midway 230 kV line	$19.319	GI-2020-13	$19.319
Barr Lake 230 kV Substation	$7.617	GI-2020-16	$7.617

The details of the Station Network Upgrades required at the Boone - Midway 230 kV POI are shown in Table 10. These costs are 100% assigned to GI-2020-13.

Table 11 – Station Network Upgrades – Boone – Midway 230 kV Line

Element	Description	Cost Est. (million)
PSCo's GI-2020-13 230kV Switching Station	Install a new 230 kV Switching Station on the Boone-Midway line. The new equipment includes: • (9) 230 kV deadend structures • (3) 230 kV 3000A circuit breakers • (8) 230 kV 3000A disconnect switches • (6) 230 kV CCVTs • (2) 230 kV SSVTs • (6) 230 kV Surge Arresters • (1) Electrical Equipment Enclosure • (2) Wave traps • Station controls and wiring • Associated foundations and structures	$14.516
PSCo's GI-2020-13 230 kV Switching Station	Install required communication in the EEE at the GI-2020-13 230 kV Switching Station	$0.450
PSCo's GI-2020-13 230 kV Switching Station	Tap line 5335 and route into GI-2020-13 230 kV Switching Station.	$1.476
PSCo's Boone 230 kV Substation	Remote end upgrade for 5335 at Boone 230 kV Substation.	$1.003
PSCo's Midway 230 kV Substation	Remote end upgrade for 5335 at Midway 230 kV Substation.	$1.003
	Siting and Land Rights support for substation construction	$0.871
Total Cost Estimate for PSCo-Funded, PSCo-Owned Interconnection Facilities		**$19.319**
Time Frame	**Site, design, procure and construct**	**36 Months**

The details of the Station Network Upgrades required at the Barr Lake 230 kV Substation POI are shown in Table 11. These costs are 100% assigned to GI-2020-16.

Table 12 – Station Network Upgrades – Barr Lake 230 kV Substation

Element	Description	Cost Est. (million)
PSCo's Barr Lake 230 kV Substation	Expand Barr Lake 230 kV Substation to accommodate GI-2020-16. The new equipment includes: • (3) 230 kV deadend structures • (4) 230 kV 3,000 A circuit breakers • (8) 230 kV 3,000 A disconnect switches • (6) 230 kV CCVTs • (2) 230 kV CVTs • (6) 230 kV surge arresters • (1) Electrical Equipment Enclosure (EEE) • Station controls and wiring • Associated foundations and structures	$4.833
PSCo's Barr Lake 230 kV Substation	Install required communication in the EEE at the Barr Lake 230 kV Substation	$0.433
PSCo's Barr Lake 230 kV Substation	Line reconfiguration to accommodate Interconnection Customer	$0.949
PSCo's Green Valley Substation	Remote end upgrade for 5759 at Green Valley 230 kV Substation	$1.157
Tri-State G&T's Reunion Substation	Reunion 5875 Line Terminal Upgrade	$0.100
	Siting and Land Rights support for substation construction	$0.145
Total Cost Estimate for PSCo-Funded, PSCo-Owned Interconnection Facilities		**$7.617**
Time Frame	**Site, design, procure and construct**	**36 Months**

5.3 Total Cost of System Network Upgrades

The Southern Colorado study pocket has one ERIS GIR: GI-2020-13. The System Network Upgrade costs associated with the ERIS GIR are described in Table 13.

Table 13 – System Network Upgrades – Southern Colorado Pocket ERIS

System Network Upgrade	Total Cost (million)	GI-2020-13	
		Cost Allocation	Cost (million)
BOONE (70061) TO GI-2020-13 P (990051) 230 kV CKT #1	$0.170	100%	$0.170
GI-2020-13 P (990051) TO MIDWAYPS (70286) 230 kV CKT #1	$0.000	100%	$0.000
CTTNWD N (78658) TO KETTLECK S (78673) 115 kV CKT #1	$2.200	100%	$2.200
Total Cost Estimate for PSCo-Funded, PSCo-Owned Network Upgrades			**$2.370**

5.4 Summary of Generation Interconnection Costs

5.4.1 For GI-2020-13

The total cost of the required system improvements for GI-2020-13 to interconnect on the Boone - Midway 230 kV Line is **$22.951 million**.

- **The cost of Transmission Provider's Interconnection Facilities is $1.262 million** (Table 8)
- **The cost of Station Network Upgrades is $19.319 million** (Table 11)
- **The cost of System Network Upgrades is $2.370 million** (Table 13)

Figure 3 is a conceptual one-line of the GI-2020-13 POI tapping to the Boone - Midway 230 kV Line.

The list of improvements required to accommodate the interconnection of GI-2020-13 are given in Table 8, Table 10, and Table 11. System improvements are subject to revision as a more detailed and refined design is produced.

5.4.2 For GI-2020-16

The total cost of the required transmission improvement required for GI-2020-16 to interconnect at the Barr Lake 230 kV Substation is **$9.097** million.

- **The cost of Transmission Provider's Interconnection Facilities is $1.480 million** (Table 9)
- **The cost of Station Network Upgrades is $7.617 million** (Table 12)
- **The cost of System Network Upgrades is $0**

5.5 Cost Estimate Assumptions

The cost estimates provided in this Phase 3 Study Report are based on the following assumptions:

- Cost estimates are in 2022 dollars with an escalation percentage and contingencies applied to the cost estimates.
- Cost estimates do not include an Allowance for Funds Used During Construction (AFUDC).
- Estimated costs include all applicable labor and overheads associated with the siting, engineering, design, and construction of the PSCo facilities to facilitate interconnection.

- Estimated costs do not include the cost for any Interconnection Customer owned equipment and associated design and engineering.
- Labor is estimated at straight time only, no overtime work is included.
- Lead times for materials were considered for the schedule.
- No costs for retail load metering are included in these estimates.
- PSCo (or its Contractor) will perform all construction, wiring, testing, and commissioning for PSCo owned and maintained facilities.
- A CPCN may be required for the construction of the Interconnection Facilities and Station Network Upgrades. The expected time to obtain a CPCN approval is 18 months.
- Estimated time to permit, design, procure and construct the interconnection facilities is approximately 18 months after authorization to proceed (post CPCN) has been obtained.
- Interconnection Customer will install two (2) redundant fiber optic circuits into the Transmission Provider's substation as part of its interconnection facilities construction scope.
- Power Quality Metering (PQM) will be required on the Interconnection Customer's generation tie-line terminating into the POI.
- Interconnection Customer will be required to design, procure, install, own, operate, and maintain a Load Frequency/Automated Generation Control (LF/AGC) RTU at their Interconnection Customer substation. PSCo will be provided with indications, readings, and data from the LF/AGC RTU.

6.0 Summary of Generation Interconnection Service

The Interconnection Customer is required to design their inverter-based resource (wind, solar or hybrid) Generating Facility to eliminate or mitigate potential for inverter or plant controller instability and/or controller response interactions with the plant controllers of existing inverter-based resource (wind, solar or hybrid) Generating Facilities.

This study only evaluated Interconnection Service of GIR in DISIS-2020-002 and Interconnection Service in and itself does not convey transmission service.

6.1 GI-2020-13

The total cost of the upgrades required to interconnect GI-2020-13 tapping to the Boone – Midway 230 kV Line for ERIS is $22.951 million (Table 8, Table 11, and Table 13).

Maximum allowable output of GI-2020-13 without requiring additional Network Upgrades is 0 MW.

ERIS of GI-2020-13 is 374 MW when using the existing firm or non-firm capacity of the Transmission System on an “as available” basis.

7.0 Contingent Facilities

The following is the list of the unbuilt Interconnection Facilities and Network Upgrades upon which the costs, timing, and study findings of the DISIS-2020-002 are dependent, and if delayed or not built, could cause a need for re-studies of the Interconnection Service or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing. The individual GIR's maximum allowable output may be decreased if these Contingent Facilities are not in-service.

Each unbuilt facility was studied as a potential contingent facility independently. The unbuilt facilities in each study pocket were reverted to the pre-project topology, and the resultant worst-case overloads were reported in Appendix B. The study generators' DFAX were calculated for the worst-case overloads. If reverting the unbuilt facility causes an overload, with >1% study generator DFAX, the unbuilt facility will be identified as a contingent facility for that study generator.

GI-2020-13: The Contingent Facilities identified for this GIR are:

- The following unbuilt transmission projects modeled in the study:
    1) Briargate South 115/230 kV transformer project tapping the Cottonwood – Fuller 230 kV line – ISD 2023,
    2) Monument – Flying Horse 115 kV Series Reactor – ISD 2022,
    3) Fuller 230/115 kV Transformer #2 – ISD 2023, and
    4) Greenwood – Arapahoe – Denver Terminal 230 kV line – ISD 2022.
- Additional Contingent Facilities identified for GI-2020-13 include the Station and System Network Upgrades and Interconnection Facilities identified in Table 8, Table 11, and Table 13.

Tables B-1 through B-4, included in Appendix B, summarize the worst-case branch overloads when an unbuilt facility is excluded from the Study Case.

Short-Circuit Contingent Breakers: There were no breakers identified requiring upgrades as a result of a short-circuit analysis performed by Xcel Energy System Protection Engineering.

8.0 Conceptual POI One-Line Diagrams of DISIS-2020-002 GIRs

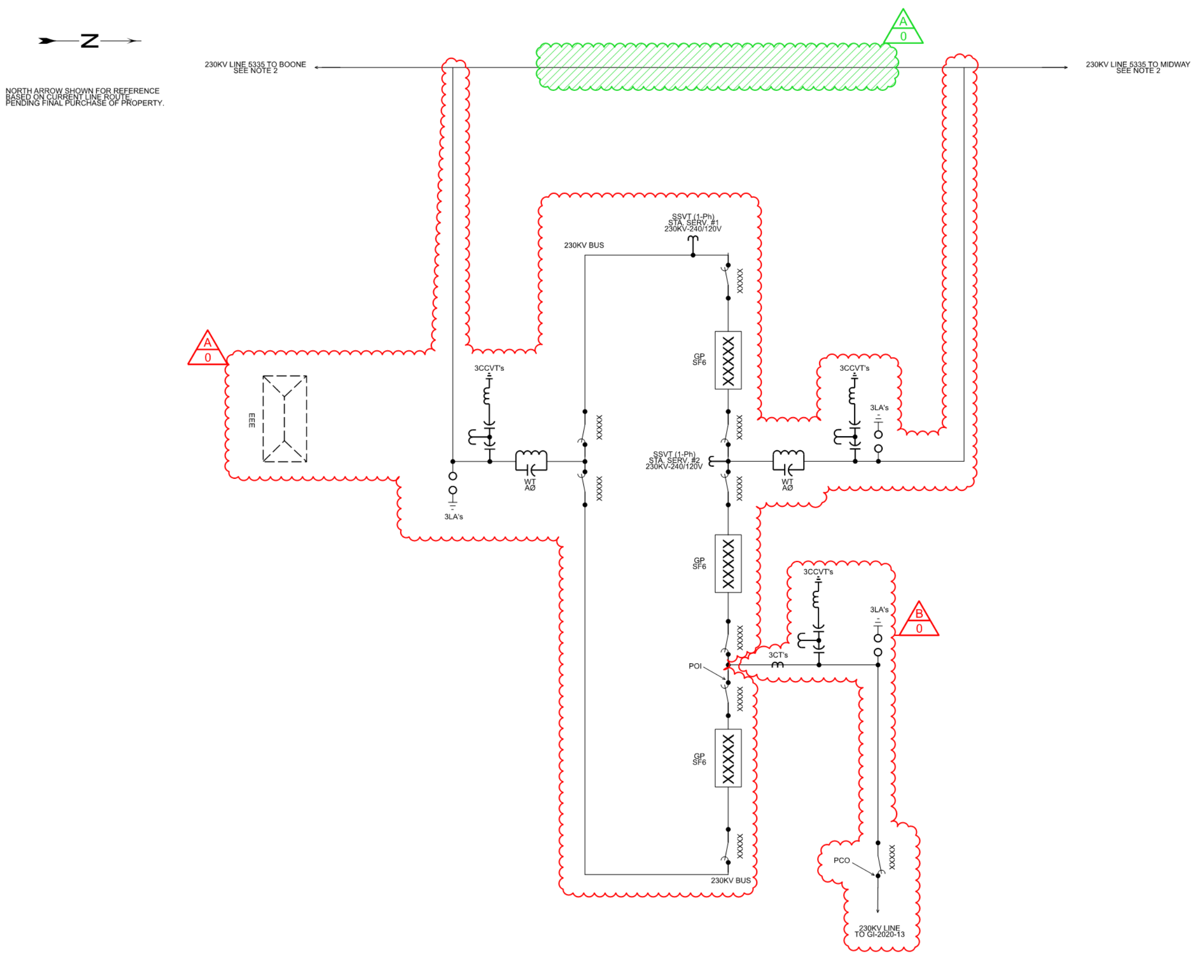

Figure 3 – Preliminary One-line of the GI-2020-13 POI

Tapping the Boone – Midway 230 kV Circuit

9.0 Appendices

Appendix A: Transient Stability Plots	26HS2a_South_ERIS_ Plots.pdf
Appendix B: Contingent Facilities' Study Results	APPENDIX B_Contingent_Facility