Interconnection Feasibility Study Report
Request # GI-2012-4

200 MW Wind Powered Generation Interconnecting at Lamar 230 kV Substation

PSCo Transmission Planning
August 24, 2013

Executive Summary

On March 13, 2013 Public Service Company of Colorado (PSCo) Transmission Planning received a generation interconnection request to determine the potential system impacts associated with interconnecting a 200 MW wind generation facility at the Lamar Substation through a 20-mile transmission line. The primary Point of Interconnection (POI) is the Lamar 230 kV bus. The customer requested a commercial operation date of December 31, 2014, and a back-feed for site energization date of June 30, 2014. Based on projected equipment lead-times and other transmission project in-service dates, the commercial operation and back-feed dates requested by the Customer were not determined feasible. An earliest date the wind generation facility could become a network resource for PSCo would be after the completion of sections of the Lamar – Frontrange Project which is conceptually planned for 2020 or beyond. The study request indicated that the generation would be delivered to PSCo native load.

This request was studied as both an Energy Resource (ER)[1] and as a Network Resource (NR)[2]. These investigations included steady-state power flow and short-circuit studies. The request was studied as a stand-alone project only, with no evaluations made of other potential new generation requests that may exist in the Large Generator Interconnection Request (LGIR) queue, other than the generation projects that are already approved. The main purpose of this study was to evaluate the potential impact of GI-2012-4 on the PSCo transmission infrastructure as well as that of neighboring entities, when injecting a total of 200 MW of wind turbine generation into Lamar 230 kV bus, and delivering the generation to native PSCo loads. The costs to interconnect the project with the transmission system at the Lamar 230 kV bus have been evaluated by PSCo Engineering. This study considered facilities that are part of the PSCo transmission system as well as monitoring other nearby entities' regional transmission systems.

[1] **Energy Resource Interconnection Service (ER 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.

[2] **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.

Energy Resource (ER) = 0 MW

The results of this feasibility study indicate that firm transmission capacity for the 200 MW wind generation facility is not available due to existing contractual limitation and firm transmission commitments and the construction of network reinforcements would be required. Non-firm transmission capability may be available depending on marketing activities, dispatch patterns, generation levels, demand levels, import/export levels of Lamar DC, and the operational status of transmission facilities.

Network Resource (NR) = 0 MW

Network Resource Interconnection Service is an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers. A Network Resource is any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Network Resource Interconnection Service in and of itself does not convey transmission service.

Contingency analyses were performed to determine the network upgrades that would be required to deliver the entire output of the GI-2012-4 wind facility as provided at the POI to PSCo native load customers. Interconnection at the 230 kV bus would require a new 345 kV switch yard adjacent to the Lamar 230 kV with two 345/230 kV autotransformers. In addition, there will be two 345 kV circuits connecting Lamar 345 kV substation to a new Avondale 345 kV substation. The new Avondale 345 kV substation will be east of Comanche. These network upgrades are part of the Lamar – Front Range study that has been extensively evaluated by members of CCPG. Under those network upgrades, the estimated cost of the recommended system upgrades to accommodate the project is approximately **$220.5M** and includes:

- *$ 1.325M for PSCo-Owned, Interconnection Facilities*
- *$ 5.164M for PSCo-Owned, Network Upgrades for Interconnection*
- *$ 214M for PSCo Network Upgrades for Delivery.*

Based upon the steady-state analysis performed for the feasibility study, the full 200 MW generation output of the GI-2012-4 project could be provided to PSCo after network upgrades noted above have been completed.

Interconnecting to the PSCo bulk transmission system requires the Customer to adhere to certain interconnection requirements. These requirements are contained in the Interconnection Guidelines for Transmission Interconnected Producer-Owned Generation Greater than 20 MW (Guidelines). The Guidelines make reference to interconnection requirements resulting from FERC Order 661A. FERC Order 661A describes the interconnection requirements for wind generation plants. In addition, PSCo System Operations conducts commissioning tests prior to

the commercial in-service date for a Customer's facilities. Some of the requirements that the Customer must complete include the following:

7. A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the POI. The Transmission Provider's System Impact Study is needed to demonstrate that such a power factor requirement is necessary to ensure safety or reliability.

8. The voltage at a POI shall be maintained in the ideal voltage range for the appropriate Colorado region and bus type (regulating[3] or non-regulating) as determined in the Rocky Mountain Area Voltage Coordination Guidelines[4]. The System Impact Study will investigate pertinent demand (on-peak or off-peak), season (summer or winter), dispatch, and outage scenarios based on the defined study area that includes the proposed POI. The study will conform to the NERC Transmission System Planning Performance Requirements (TPL standards).

9. The POI for a wind generating facility cannot be declared a regulating bus unless system studies demonstrate that the designation of the POI as a regulating bus is needed for system reliability or safety.

10. The impact of the wind generating facility on the reactive power schedules of nearby generating units may need to be mitigated by the Customer if system studies demonstrate that the proposed wind generating facility causes nearby generating units to generate or absorb reactive power for voltage control[5]. It is understood that sufficient reactive power reserve must be maintained on generating units to allow them to dynamically regulate voltage for extreme system conditions.

11. If a wind generating facility is interconnected to the bulk transmission system but is operating with its generation off-line and receiving power from the bulk transmission system for its station service requirements, that facility is acting as a load and will be required to maintain the power factor at the POI within 98% lagging or leading (when the

[3] A regulating bus is defined in the Rocky Mountain Area Voltage Coordination Guidelines as any transmission or generation bus with controllable VAR's. This implies that the bus has a voltage schedule that is being regulated by a generating facility. Generating facilities include Static VAR Compensators (SVC's), synchronous generators, or synchronous condensers that can supply fast-acting reactive power (VAR) compensation to dynamically regulate voltage at a power system bus. Switchable capacitors, switchable reactors, load tap changing transformers, etc. are not defined as generating facilities as they do not provide controllable dynamic VARs'.

[4] The Voltage Coordination Guidelines Subcommittee (VCGS) of the Colorado Coordinated Planning Group developed the guidelines. The subcommittee consisted of representatives from major Colorado utilities including Colorado Springs Utilities, Platte River Power Authority, Tri-State Generation and Transmission, Public Service Company of Colorado, and Western Area Power Administration-Rocky Mountain Region. Other major utilities outside of Colorado were also involved in the development of these guidelines.

[5] The Rocky Mountain Area Voltage Coordination Guidelines (July 2006), page 8 of 34, Item 6, states that "Static VAR sources (switched shunt capacitors, reactors) should be operated to control the voltage profile before relying on LTC or generator VAR output, and should be used in such a manner to keep LTC transformers near their nominal tap range and to keep reactive margin on generating equipment. The rationale for this goal is that the generator is a dynamic reactive source that can provide high-speed reactive support to the transmission system after a disturbance that results in low voltages, or conversely are in a position to reduce voltages after a contingency that results in high voltages. Keeping transformers near their mid-tap range also allows for maximum response to either boost or reduce voltages following a disturbance".

station service load is greater than 85% of maximum) per the Xcel Energy document titled Interconnection Guidelines For Transmission Interconnected Customer Loads.

12. PSCo System Operations will require the Customer to perform operational tests prior to commercial operation that would verify that the equipment installed by the Customer meets operational requirements.

13. It is the responsibility of the Customer to determine what type of equipment (DVAR, added switched capacitors, SVC, reactors, etc.), the ratings, and the locations of those facilities that may be needed for acceptable performance during the commissioning testing.

PSCo requires the Customer to provide a single point of contact to coordinate compliance with the power factor and voltage regulation at the POI. The reactive flow at the end of the line near the POI will need to be controlled according to the Interconnection Guidelines.

The Interconnection Agreement (IA) requires that certain conditions be met, as follows:

1. The conditions of the Large Generator Interconnection Guidelines[6] (LGIG) are met.

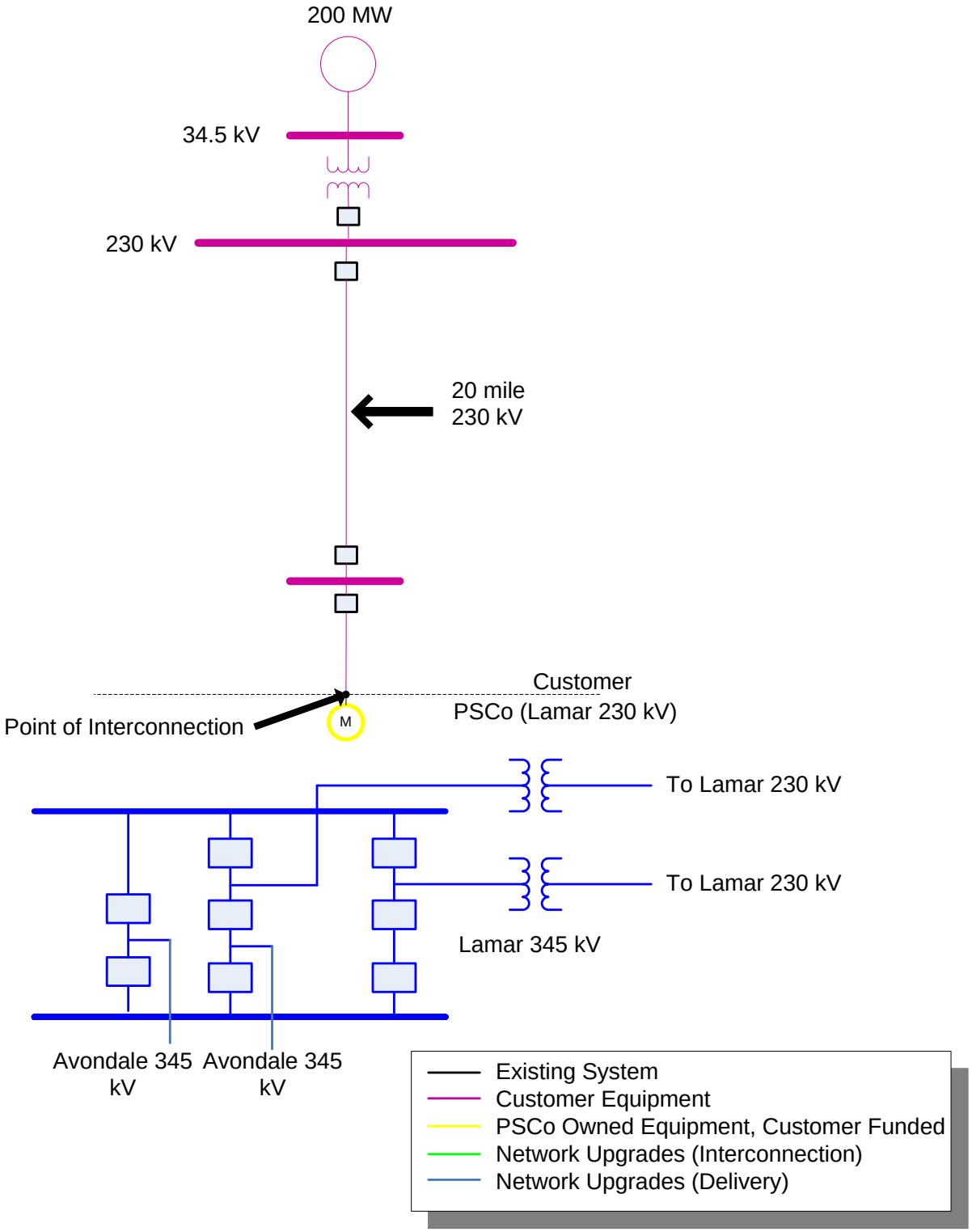
2. A single point of contact is given to Operations to manage the transmission system reliably for all wind projects using the transmission facilities associated with GI-2012-4 that deliver power to the Pawnee POI, as indicated in the Interconnection Guidelines.

3. PSCo will require testing of the full range of 0 MW to 200 MW of the wind project. These tests will include, but not be limited to, power factor (pf) control, and voltage control as measured at the Pawnee POI for various generation output levels (0 to 200 MW) of the overall wind generation facility.

4. The Customer must show that the power factor at the POI is within the required +/-0.95 power factor range at all levels of generation and that the voltage levels and changes are within reliability criteria as measured at the POI for the full range of testing (including generator off-line conditions).

[6] Interconnection Guidelines for Transmission Interconnected Producer-Owned Generation Greater than 20 MW, version 3.0, 12/31/06

Figure 1 Preliminary One-Line of the Proposed GI-2012-4



1. Introduction

Public Service Company of Colorado (PSCo) received a large generator interconnection request (GI-2012-4) to interconnect 125 GE 1.6 MW wind turbines, with a total generator nameplate capacity of 200 MW. The customer requested a commercial operation date of December 31, 2014, and a back-feed for site energization date of June 30, 2014. The GI-2012-4 project would be connected with a new customer owned 20-mile transmission line to the Lamar 230 kV bus. This request is evaluated as a stand-alone project with no other higher queued projects modeled.

The Customer has requested that this project be evaluated as a Network Resource (NR) and an Energy Resource (ER), with the energy delivered to PSCo native load customers.

2. Methodology and Criteria

A. Types of Analysis, Benchmarking, and System Monitoring

This study determined reliability performance based on steady state power flow analysis. System performance was benchmarked using the starting base case, which was used to document regional performance and other issues prior to the interconnection of new generation at Lamar Substation and prior to the implementation of any transmission mitigation project.

Study criteria for this study was consistent with technical studies performed for the Lamar – Front Range transmission project; namely:

1. All buses, lines, and transformers with base voltages greater than or equal to 69 kV in the Colorado power flow areas 70 and 73 were monitored in all study cases.
2. Post-contingency element loading was only tabulated when an element rating was exceeded and the loading increase was at least 1% from the normal system loading. Specifically, if an element was overloaded in the normal condition but increased less than 1% in the outage condition, the overload was not be reported.
3. Post-contingency voltage violations were tabulated only if they deviated by more than 0.05 p.u. from the normal system voltage (or higher, if allowed by local criteria). Base case and contingency low voltage violations were noted, but contingency voltage violations were ignored if the voltage change was less than 0.05 p.u.

B. Contingencies Considered

The study focused on NERC Category A (N-0, system intact) and Category B (N-1, single contingency) performance, as well as selected NERC Category C common-tower disturbances. The list of Category B and Category C contingencies is identical to the list of outages used for Lamar – Front Range studies.

C. Criteria

The study adhered to NERC Standards and WECC Criteria. For element loading, the following criteria were used:

- All elements within 100% of stated ratings.
- All voltages within 0.95 and 1.05 under system normal conditions.
- All voltages within 0.90 and 1.05 under single contingency conditions.
- Voltages must not deviate by 5% or more for Category B contingencies.
- Voltages must not deviate by 10% or more for Category C contingencies.

3. Power Flow Study Process

A. Starting Base Case for Lamar Generation Interconnection Study

The starting benchmark or pre-project, base case for this interconnection study was built from the final base cases developed for the Lamar – Front Range project, which model 2020 summer peak conditions. The Lamar – Front Range study cases were developed from the study base case used for the High Plains Express study because the model for the study area had already been closely examined and fine-tuned for that study. The 2019hs1a WECC base case, created in 2009, was the original source for the study case, but modeling in the Colorado area has been extensively updated from the original case. Only the generation interconnection projects and the mitigation facilities were added to the starting Lamar – Front Range Project base case to create the Lamar Generation Interconnection study pre-project case.

The study cases model heavy south-to-north transfers in the Colorado system, especially when re-dispatching for increased generation injections in the Lamar area. The cases model most existing or planned generation in the Comanche and Lamar areas at or near maximum levels. The pre-project generation dispatch in areas 70 and 73 (mostly Colorado) in the study benchmark peak case is identical to the generation dispatch in the Lamar – Front Range study cases. The differences between the pre-project and post-project generation dispatch are described in Table 2.

The Lamar – Front Range project revealed certain problems in the Denver Metro Area transmission system associated with south-to-north flow along Colorado's Front Range. As a result, a second Leetsdale 230/115 kV 280 MVA autotransformer was added to the model in the case, connected to the other 115 kV bus. This is an assumed system upgrade that is not considered to be a part of the Lamar – Front Range Project or with generation interconnections in the Lamar area.

B. Mitigation Facilities

The existing transmission system in the Lamar area has no capacity for additional generation injections (see Table 3). Mitigation for additional generation injections requires a portion of the planned Lamar – Front Range project facilities to be constructed. These facilities consist of the following:

- Construct a new Avondale 345 kV Substation located approximately 6 miles south and 6 miles east of Comanche and 15 miles west of Boone with six 345 kV line terminations

- Sectionalize the two existing Daniels Park – Comanche 345 kV circuits by terminating them at the Avondale 345 kV bus, creating two Daniels Park – Avondale 345 kV circuits and two Avondale – Comanche 345 kV circuits
- Construct a new 345 kV bus at Lamar Substation with four terminations
- Construct two new 230 kV terminations at the existing Lamar 230 kV bus
- Install two 560 MVA, 345/230 kV autotransformers to interconnect the Lamar 345 kV and 230 kV buses
- Construct one new double-circuit 345 kV line from Lamar Substation 345 kV bus to Avondale Substation 345 kV bus using double-bundled 1272 Bittern ACSR conductor (1183 MVA)
- Install one 40 MVAR shunt reactor each at the Lamar 345 kV bus and at the Avondale 345 kV bus to control high off-peak voltages

C. Study Process

In pursuant to section 6.3 of Attachment N of PSCo OATT, Transmission Provider shall utilize existing studies to the extent practicable when it performs the study.

In addition, the following study process was used to analyze the benchmark transmission configuration and the post-project transmission configuration with mitigation projects to quantitatively measure the results and determine whether there are limiting factors or criteria violations associated with each configuration. Table 1 describes important details of each study configuration analyzed.

Table 1: Lamar GI Study Matrix	Pre-Project	Post-Project
• Wind Generation Interconnection at Lamar bus		X
• 162 MW full output modeled at existing Colorado Green wind generation project	X	X
• 75 MW full output modeled at existing Twin Buttes wind generation project	X	X
• 210 MW full import modeled at Lamar AC-DC-AC intertie	X	X
• Lamar Substation 345 kV bus modeled		X
• Two Lamar 345/230 kV transformers (560 MVA normal/emergency)		X
• Avondale Substation 345 kV bus modeled		X
• Two Lamar-Avondale 345 kV ckts (bundled 1272 Bittern ACSR conductor, 1183 MVA)		X
• Two Daniels Park-Comanche 345 kV circuits looped into Avondale 345 kV bus (forming two Daniels Park - Avondale and two Avondale - Comanche 345 kV lines)		X
• 40 MVAR shunt reactors modeled at Lamar and Avondale 345 kV buses (voltage control)		X

D. Generation Dispatch

Table 2 compares the generation dispatch in the pre-project and post-project cases. Note that generation injections at Lamar displace generation to the north, increasing south-to-north flow.

Table 2: Lamar GI Generation Dispatch Comparison	Pre-Project	Post-Project	
	MW	MW	Delta
• Wind generation modeled at Lamar 230kV Bus	0	200	+200
• RMEC generation plant total gross output	600	540	-60
• Spindle generation plant total gross output	260	200	-60
• Rawhide coal unit gross output	290	213.4	-76.6
• Cherokee Unit #3 gross output	138.9	130.1	-8.8
• Area 70 total transmission losses (negative generation)	-217.7	-212.8	(+4.9)
		Net Change:	-0.5

4. Power Flow Results

A. Benchmark (Pre-Project) Case Study Results

Table 3 documents Category B overloads with a TDF less than 1% to show overloads that are disregarded based on TDF screening criteria. These overloads are considered to be problems in the benchmark system case and not the responsibility of the generator developer to mitigate.

Table 4 shows the results of contingency analysis for Category B (single contingency) outages. The Pre-Project column shows the results for the benchmark case. The Pre-Project case results show that:

- The Lamar 230/115 kV transformer bank is overloaded by almost 19% in the benchmark case with no outages
- The Lamar 230/115 kV transformer bank outage causes the power flow study case to diverge and demonstrates that this outage causes voltage collapse in the Lamar area

These results show that the existing system has zero available transfer capability and, therefore, no ability to handle additional generation interconnected in the Lamar area without significant transmission reinforcements. Fortunately, the Lamar – Front Range Project has provided a template for the required transmission upgrades in this area that mitigate problems with additional generation injections at Lamar and also fit in with long-term transmission plans for the area.

B. Post-Project Case Study Results

Mitigation facilities consistent with the Lamar – Front Range Project transmission plan are included in the post-project case to allow new generation to be injected in the Lamar area. Contingency analysis has been performed on the post-project case to verify that these

mitigation plans are adequate to resolve criteria violations otherwise caused by additional generation in the Lamar area.

Category A and B overloads considered to be exacerbated or caused by increased generation in the Lamar area in the post-project case are shown in Table 4. These results show the following:

- No normal (**Category A**) overloads are present in the post-project case. Note that the Lamar 230/115 kV transformers in the pre-project case are fully mitigated in the post-project cases with mitigation facilities.
- For single contingency (**Category B**) outages, Table 4 shows exacerbated overloads on the following facilities in the post-project case:
  - *Briargate – Cottonwood 115 kV line, Cottonwood – Kettle Creek 115 kV line, Monument – Palmer Lake 115 kV line, and Kelker 230/115 kV transformer:* These overloads are part of the Colorado Springs Utilities transmission system and were observed repeatedly in Lamar – Front Range studies. These CSU overloads are disregarded for the purposes of this study because these existing problems are only slightly exacerbated and they have a potential simple solution that will resolve both pre-project and post-project overloads. Generation injections in the Lamar area are primarily transmitted to Comanche, from which much of the power travels northward to Daniels Park. CSU facility overloads are observed with high south-to-north power transfer between Midway and Daniels Park, part of which passes through the CSU system. Similar CSU overloads have also been identified in other long-term studies. CSU has proposed a simple, effective solution: add a phase-shifting transformer to control power on the Flying Horse – Monument 115 kV line. Lamar – Front Range project studies demonstrated that this solution could effectively mitigate problems caused by heavy south-to-north loading in the CSU system.
  - *San Luis Valley 230/115 kV transformer bank for outage of the parallel transformer bank:* These 150 MVA transformer banks overload for an outage of the parallel bank for the benchmark cases, and the overloads are slightly exacerbated in the post-project case. **This is an issue that has been identified in San Luis Valley studies as a problem to be resolved, so this issue is considered to be outside the scope of this project to resolve and is disregarded for the purposes of this study.**
  - *Daniels Park – Prairie – Greenwood 115 kV lines, Waterton – Martin Tap 115 kV line:*

    These Denver Metro Area facilities show small overloads in the post project cases, but these local issues are present for any increased south-to-north flow into that area, which is quite remote from the Lamar area. As such, they are disregarded for the purposes of this analysis.
- For credible double contingency (**Category C**) outages, Table 5 shows exacerbated overloads on the following facilities in the post-project case:

- *Outage of Lamar – Avondale #1 & 2 345 kV lines*:

  This outage causes the power flow solution to diverge, indicating a local area voltage collapse due to severe overloading of the Lamar 230/115 kV transformer and the 230 and 115 kV systems between Lamar and Comanche. As a result, **a Special Protection System must be installed to trip new generation interconnected in the Lamar area following this outage.**

- *Outage of Daniels Park – Avondale #1 & 2 345 kV lines*:

  A variety of overloads, many of which are present in the pre-project case for the outage of the Daniels Park – Comanche #1 & 2 345 kV lines, are significantly exacerbated in the post-project case. Because of these increased overloads, **the SPS installed to trip new generation interconnected in the Lamar area should also be triggered for this outage.**

Voltage violations potentially exacerbated in the post-project case are shown in Table 6. The results show that there are no significant adverse voltage impacts exacerbated by the post-project case. Two contingencies result in slightly exacerbated voltage results very remote from the Lamar area that are disregarded, and the loss of the Lamar 230/115 kV transformer, though it results in voltage criteria violations on the 115 kV and 69 kV systems, actually improves the results compared to the pre-project case, in which the same outage resulted in voltage collapse.

Xcel Energy

TABLE 3: LOW TDF (DISREGARDED) CATEGORY B OVERLOADS [200 MW AT LAMAR 230KV BUS]

These overloads have a very low or negative correlation to increasing generation injections at Lamar (disregarded overloads).

Circuit	Rating	Contingency	Pre-Project	Post-Project	
			% Rtg	% Rtg	TDF
79021 CURECANT 230 - 79020 CURECANT 115 #1	75 MVA	CURECANT-LOSTCANY 230 Line #1	110.7%	113.2%	0.93%
73407 KELKER N 230 - 73409 KELKER W 115 #1	266 MVA	KELKER S-KELKER E 230/115 #1		100.3%	0.65%
70108 CHEROKEE 115 - 70174 FEDERHT 115 #1	783.2 Amp	VALMONT -SPNDLE 230 Line #1		101.4%	0.13%
70463 WATERTON 115 - 70522 ROXBOROU 115 #1	632.6 Amp	CASTLRCK-WOLFSBTP 115 Line #1	116.6%	116.8%	0.12%
70381 SEDALIA 115 - 70522 ROXBOROU 115 #1	632.6 Amp	CASTLRCK-WOLFSBTP 115 Line #1	106.6%	106.7%	0.11%
79029 FLAMGORG 69 - 79026 FLAMGORG 138 #1	19 MVA	FONTNLLE 4.20 #1 Generator	129.8%	129.8%	0.03%
70397 B.CRK_PS 115 - 70399 B.CRK_PS 230 #T1	224 MVA	B.CRK_PS-BEAVERCK 115 Line #1	100.7%	100.7%	0.01%
70005 BRUSH_SS 115 - 70397 B.CRK_PS 115 #2	923.8 Amp	BRUSH_SS-B.CRK_PS 115 Line #1	123.6%	123.6%	0.00%
70005 BRUSH_SS 115 - 70397 B.CRK_PS 115 #1	923.8 Amp	BRUSH_SS-B.CRK_PS 115 Line #2	123.6%	123.6%	0.00%
73008 ARCHER 115 - 73183 SKYLINE 115 #1	607.5 Amp	CHEYENNE-HAPPYJCK 115 Line #1	140.9%	140.8%	-0.06%
73190 STEGALL 230 - 73189 STEGALL 115 #1	100 MVA	STEGALL -STEGALL 230/115 #2	134.0%	133.8%	-0.11%
70244 LAFAYETT 115 - 70444 VALMONT 115 #1	799.8 Amp	FTLUPTON-FTLUPTON 230/115 #T1	103.0%	102.4%	-0.51%
73088 HOYT 115 - 73493 SANDCRK 115 #1	602.5 Amp	BRIGHTNW-ERIE SW 115 Line #1	102.8%	102.8%	-0.01%
79034 GRANDJCT 115 - 79035 GRANDJCT 138 #T2	50 MVA	GRANDJCT-RIFLE_CU 345 Line #1	100.4%		

TABLE 4: CATEGORY "A" & "B" OVERLOADS [200 MW AT LAMAR 230KV BUS]

The TDF, or Transfer Distribution Factor, for each circuit represents the percentage of the increased generation that flows on that circuit.

Table is filtered to exclude TDF < 1% to capture only overloads exacerbated by increasing generation at Lamar.

Red fill indicates that the contingency diverged, typically due to voltage collapse.

Circuit	Rating	Contingency	Pre-Project	Post-Project	
			% Rtg	% Rtg	TDF
***	***	LAMAR_CO-LAMAR_CO 230/115 #T1	999.0%		
73389 BRIARGAT 115 - 73393 CTTNWD S 115 #1	753.1 Amp	CTTNWD N-KETTLECK 115 Line #1	132.0%	134.5%	1.8%
73391 CTTNWD N 115 - 73410 KETTLECK 115 #1	903.7 Amp	BRIARGAT-CTTNWD S 115 Line #1	119.2%	121.6%	2.2%
70254 LAMAR_CO 230 - 70253 LAMAR_CO 115 #T1	100 MVA	BOONE -MIDWAYPS 230 Line #1 **ALL LINES IN SERVICE**	121.8% **118.6%**		
70374 SANLSVLY 115 - 70375 SANLSVLY 230 #T2	150 MVA	SANLSVLY-SANLSVLY 230/115 #T1	108.6%	110.9%	1.8%
70374 SANLSVLY 115 - 70375 SANLSVLY 230 #T1	150 MVA	SANLSVLY-SANLSVLY 230/115 #T2	108.6%	110.9%	1.8%
70308 PALMER 115 - 73414 MONUMENT 115 #1	676.8 Amp	DANIELPK-FULLER 230 Line #1	100.4%	104.1%	2.4%
70139 DANIELPK 230 - 70331 PRAIRIE1 230 #1	1199.9 Amp	DANIELPK-PRAIRIE3 230 Line #1		101.6%	29.0%
70108 CHEROKEE 115 - 70174 FEDERHT 115 #1	783.2 Amp	VALMONT -SPNDLE 230 Line #1 CHEROKEE-SEMPER 115 Line #1	101.2%	 101.0%	 2.9%
70463 WATERTON 115 - 70484 MARTN2TP 115 #1	632.6 Amp	SODALAKE-SODALAKE 230/115 #T2		100.4%	2.8%
70254 LAMAR_CO 230 - 70700 CO_GRN 230 #1	599.9 Amp	LAMAR_CO-WILOW_CK 115 Line #1	100.2%		

TABLE 5: CATEGORY "C" OVERLOADS [200 MW AT LAMAR 230KV BUS]

The TDF, or Transfer Distribution Factor, for each circuit represents percentage of increased gen that flows on that circuit (no filtering).

For the Benchmark Case (Case 0), the Daniels Park-Comanche #1 & 2 345kV line outage is substituted for the Daniels Park-Avondale #1&2 and Avondale-Comanche #1&2 345kV line outages.

Red fill indicates that the contingency diverged, typically due to voltage collapse.

Contingency	Circuit	Rating	Pre-Project	Post-Project	
			% Rtg	% Rtg	TDF
DANIELPK-AVONDALE 345 Ln #1&2	70254 LAMAR_CO 230 - 70253 LAMAR_CO 115 #T1	100 MVA	120.9%		
	70308 PALMER 115 - 73414 MONUMENT 115 #1	676.8 Amp	133.2%	146.0%	8.6%
	70285 MIDWAYPS 115 - 70286 MIDWAYPS 230 #T1	100 MVA	114.4%	131.9%	11.5%
	70286 MIDWAYPS 230 - 70465 MIDWAYPS 345 #T2	560 MVA		101.0%	26.0%
	70449 DESRTCOV 115 - 70456 W.STATON 115 #1	602.5 Amp	108.4%	121.4%	7.8%
	73410 KETTLECK 115 - 73576 FLYHORSE 115 #1	903.7 Amp	112.0%	123.2%	10.2%
	73391 CTTNWD N 115 - 73410 KETTLECK 115 #1	903.7 Amp		107.0%	6.8%
	73714 MONU PST 115 - 73576 FLYHORSE 115 #1	903.7 Amp	105.6%	116.9%	10.2%
	70007 OVERTON 115 - 70031 APT_TAP 115 #1	612.5 Amp	106.6%	111.3%	2.9%
	70339 PUEBPLNT 115 - 70352 READER 115 #1	798.2 Amp		101.7%	9.2%
AVONDALE-COMANCHE 345 Ln #1&2	70308 PALMER 115 - 73414 MONUMENT 115 #1	676.8 Amp	133.2%	106.4%	-18.0%
LAMAR-AVONDALE 345 Line #1&2	***	***		999.0%	

TABLE 6: VOLTAGE CRITERIA VIOLATIONS [200 MW AT LAMAR 230KV BUS]

Table filtered to exclude outages with no voltage deviations **< 0.5%** from pre-project result (to capture only negative impacts).

Vpu is per unit bus voltage; %DecOrig is % voltage reduction from no-outage case (5% limit for Cat. B outages);
%DecCtgcy is % voltage reduction from pre-project contingency result (filtered to show only > 0.5% changes).

Red fill indicates that the contingency diverged, typically due to voltage collapse.

		Pre-Project		Post-Project		
Contingency	Bus	Vpu	%DecOrig	Vpu	%DecOrig	%DecCtgcy
PEETZ -SIDNEY 115 Line #1	73150 PEETZ 115	0.93	7.4%	0.92	8.0%	0.7%
	70722 RDGCREST 115	0.93	7.4%	0.92	8.0%	0.7%
N.YUMA -N.YUMA 230/115 #1	73166 REDWILLW 115			0.92	5.7%	
	73142 N.YUMA 115	0.93	5.0%	0.92	6.0%	1.0%
LAMAR_CO-LAMAR_CO 230/115 #T1	***	0.00	0.0%			
	70452 VILAS 115			0.86	9.7%	
	70253 LAMAR_CO 115			0.88	9.9%	
	70472 WILOW_CK 115			0.88	7.7%	
	70425 T.BUTTES 69			0.94	7.0%	
	70460 WALSH 69			0.94	7.5%	
	70404 SPRNGFLD 69			0.94	7.9%	
	70223 HLTP_TP 69			0.94	7.9%	
	70222 HILLTOP 69			0.94	7.9%	
	70102 CHENEY 69			0.94	5.9%	
	70453 VILAS 69			0.95	7.8%	
	70101 CHEN_TAP 69			0.95	5.9%	

Based on the information presented in this report, the mitigation facilities modeled in the post-project case are effective at mitigating almost all adverse impacts associated with additional generation injected in the Lamar area. The only additional mitigation required is a Special Protection Scheme to trip the new generation for either of two Category C double contingencies of the new mitigation facilities.

Energy Resource (ER) = 0 MW

The results of this feasibility study indicate that firm transmission capacity for the 200 MW wind generation facility is not available due to existing contractual limitation and firm transmission commitments and the construction of network reinforcements would be required. Non-firm transmission capability may be available depending on marketing activities, dispatch patterns, generation levels, demand levels, import/export levels of Lamar DC, and the operational status of transmission facilities.

Network Resource (NR) = 0 MW

Network Resource Interconnection Service is an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers. A Network Resource is any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Network Resource Interconnection Service in and of itself does not convey transmission service.

5. Short Circuit Analysis

The short circuit study results show that the fault current levels for all buses studied are within the interrupting ratings of the breakers; therefore, the Project and associated infrastructure will not cause fault current to exceed the circuit breaker ratings.

The fault currents at the Lamar 230 kV substation are 11,731 amps for a single-line to ground fault and 12,064 amps for a three-phase fault. These values assume little to no fault current contribution from the proposed wind facility.

6. Costs Estimates and Assumptions

The estimated total cost for the required upgrades for is **$ 220.5M.**

The estimated costs shown are (+/-30%) estimates in 2013 dollars (no escalation applied) and are based upon typical construction costs for previously performed similar construction. These estimated costs include all applicable labor and overheads associated with the engineering, design, and construction of these new PSCo facilities. This estimate did not include the cost for any other Customer owned equipment and associated design and engineering. The Interconnection Feasibility Study will provide a list of facilities and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

The following tables list the improvements required to accommodate the interconnection and the delivery of the Project. The cost responsibilities associated with these facilities shall be handled

as per current FERC guidelines. System improvements are subject to change upon more detailed analysis.

Table 7: PSCo Owned; Customer Funded Interconnection Facilities

Element	Description	Cost Est. (Millions)
PSCo's Lamar 230kV Transmission Substation	Interconnect Customer to tap at PSCo's Lamar 230 kV Substation. The new equipment includes: • Three (3) 230 kV gang switches • Three (3) 230 V combination CT/PT metering units • Three (3) 230 kV lightning arresters • One relay panel • Associated bus, wiring and equipment • Associated foundations and structures • Associated transmission line communications, relaying and testing	**$0.753**
	Transmission line tap into substation. Structure, conductor, hardware and installation labor.	**$0.71**
DEGs Wind I 230kV Substation	Load Frequency/Automated Generation Control (LF/AGC) RTU and associated equipment.	**$0.501**
	Transmission line interconnection/tie to be customer owned 230 kV circuit.	**N/A**
	Total Cost Estimate for PSCo-Owned, Customer-Funded Interconnection Facilities	**$1.325**
Time Frame	**Design, procure and construct**	**24 months**

Table 8: PSCo Owned; PSCo Funded Interconnection Facilities

Element	Description	Cost Estimate (Millions)
PSCo's Lamar 230kV Transmission Substation	. The new 230 kV equipment includes: • Six (6) 230 kV circuit breakers • Twelve (12) 230 kV gang switches • Eight (8) 230 kV CCVT's • 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	**$5.164**
	Siting and Land Rights support for substation land acquisition and construction.	**N/A**
	Total Cost Estimate for PSCo-Owned, PSCo-Funded Interconnection Facilities	**$5.164**
Time Frame	**Site, design, procure and construct**	**24 months**

Table 9: PSCo Network Upgrades for Delivery

Element	Description	Cost Estimate (Millions)
PSCo's Lamar 345kV Transmission Substation	The new equipment includes: • Ten (10) 345 kV circuit breakers • Nineteen (19) 345 kV gang switches • Two (2) 345kV, 560 MVA Auto-Transformers • Six (6) 345 kV lightning arresters • Two (2) Station Service Transformers • 40 MW shunt reactor • 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	**$30**
PSCo's Avondale 345 kV Transmission Substation	The new equipment includes: • Ten (10) 345 kV circuit breakers • Nineteen (19) 345kV gang switches • Six (6) 345 kV lightning arresters • Two (2) Station Service Transformers • 40 MW shunt reactor • 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	**$20**
Lamar – Avondale double circuit 345 kV	• 109 miles of 345 kV double circuit steel pole line configuration • ROW = 200 ft. • Double bundle 1272 kcmil 45/7 ACSR "Bittern" • 1-3/8'' EHS Steel Shield Wire • 1-48 Fiber OPGW • 601-DC Steel Pole Tangent Strs. (145 ft. Height, 1,000 ft. spans) • 24 – DC 2-Pole Steel Deadend Strs. (145 ft. Height, 1,000 ft. spans)	**$164**
Total Cost		**$214**
Time Frame	**Site, design, procure and construct**	**7 – 10 years**

Cost Estimate Assumptions

- Scoping level cost estimates for Interconnection Facilities and Network/Infrastructure Upgrades for Delivery (+/- 30% accuracy) were developed by PSCo Engineering.
- Estimates are based on 2013 dollars (appropriate contingency and escalation applied).
- AFUDC has been excluded.
- Labor is estimated for straight time only – no overtime included.
- Lead times for materials were considered for the schedule.
- 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 to be determined.
- A CPCN will be required for the PSCo interconnection facilities construction.
- Customer will string OPGW fiber into substation as part of the transmission line construction scope.
- Customer will provide space for PSCo equipment in its Electrical Equipment Enclosure.
- Station service provided primarily from a station service VT and secondly by the local utility provider.

7. Schedule

This project will likely take 7 – 10 years to construct and it would require a CPCN from the Colorado PUC.