System Impact Study Report
Cluster Request GI-2006-1
Portfolios A-I

Public Service Company of Colorado
All-Source Request for Proposals

Transmission Reliability and Assessment

May 25, 2006

I. Executive Summary

This System Impact Study Report summarizes the analyses performed by Public Service Company of Colorado (PSCo) Transmission to evaluate request GI-2006-1, which is a "cluster" of potential generation resources as requested by Xcel Energy Markets (XEM) for the 2003 Colorado Least Cost Resource Plan. For this study, the cluster of resources consisted of a pool of nine potential generator interconnections. As part of their All-Source evaluation, XEM also reviewed bids that would renew or extend existing contracts for generation for PSCo. However, the cluster used for this System Impact Study consists only of new resource projects, and any existing contracts were assumed to be in place for the time frame modeled in studies. The cluster consists of three wind projects and six gas-fired projects. From that cluster, nine subset combinations, or "portfolios[1]" of resources were evaluated. Table 1 shows the bids that made up the GI-2006-1 cluster. The portfolios are referenced by letters A through I. The cluster of resources and the portfolios studied are shown in Table 1. Simple figures for each interconnection are shown in Section VIII.

All projects were evaluated as Network Resources, with power going to PSCo customer loads. When modeling the wind projects, it was assumed that other PSCo resources in the vicinity of each wind project would be used to manage any potential transmission limitations. Therefore, costs associated with the wind projects only consist of those associated with Interconnection of the facilities. Table 1 shows the estimated PSCo Network Upgrade costs for Interconnection and Delivery as indicated by the analyses[2].

II. Study Scope and Analysis

As part of the PSCo 2003 Least Cost Resource Plan, and subsequent Request for Proposals, multiple bids were evaluated at a feasibility level on a stand-alone basis. The purpose was to evaluate the viability of those bids on an individual bid basis from a transmission system impact perspective. Following that analysis, XEM submitted a formal request to PSCo Transmission on January 10, 2006. The request identified a cluster of proposals that would proceed under the FERC LGIP process for more detailed analysis. From that cluster, several potential portfolios of resources were identified by XEM to meet future load growth. A System Impact Study Agreement was executed February 10, 2006, and this report summarizes the transmission requirements associated with the proposed interconnections to the PSCo Transmission System.

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[1] This report uses the term "cluster" to refer to the pool of all generators studied. The term "portfolio is used to describe each subset of generation projects, as requested by the Customer.
[2] Cost figures are in 2006 dollars and include applicable overheads.

Table 1 Generation Interconnection Cluster and Portfolios

Resource Description					In Service Dates		Portfolios								
Bid #	**Facility**	**Interconnec-tion**	**MW**	**Type**	**Estimated Backfeed**	**Requested Commercial**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**
W009	Logan	Pawnee	400	Wind	12/1/06	12/31/06	400	400	400	400	400	400	400	400	400
W014	CO Green	Lamar	75	Wind	1/1/07	3/1/07	75	75	75	75	75	75	75	75	75
W022	Cedar Creek	RMEC	300	Wind	7/1/07	11/1/07	300	300	300	300	300	300	300	300	300
G004	Plains End	Plains End	115	Gas	2/1/07	5/1/07						113		113	
G020/22	Thermo	Ft.Lupton	91/23	Gas	5/1/07	5/1/07		91		91		23	23	23	23
G025	Spruce	Spruce	264	Gas	2/15/07	6/1/07	264			264	264	264	264		
G029	Spindle	Frederick	269	Gas	12/1/06	5/1/07	269	269	269			269	269	269	269
G031	Squirrel	Com-DP 345	483	Gas	11/1/08	5/1/09	483	483	483	483	483				
G043	Havanna	Silver Saddle	168	Gas	4/1/07	6/1/07		168	168	168	168			168	168
Totals							1791	1786	1695	1781	1690	1444	1331	1348	1235
Network Upgrade Costs															
Interconnection							**$17.11**	**$17.14**	**$16.92**	**$15.41**	**$15.19**	**$9.98**	**$9.29**	**$9.78**	**$9.10**
Delivery		Power Flow					$34.66	$35.61	$35.61	$32.86	$32.86	$9.98	$6.16	$10.93	$7.11
		Transient Stability					**$0.70**	**$0.70**	**$0.70**			**$0.70**	**$0.70**	**$0.70**	**$0.70**
		Short Circuit					$3.80	$4.01	$3.24	$4.61	$3.84	$3.61	$3.61	$2.84	$2.84
		Total Delivery					**$40.46**	**$41.62**	**$40.85**	**$37.47**	**$36.70**	**$15.59**	**$11.77**	**$15.77**	**$11.95**
Total Portfolio Costs							**$56.28**	**$57.46**	**$56.47**	**$52.88**	**$51.89**	**$24.27**	**$19.76**	**$24.25**	**$19.75**

The Study consisted of power flow, short circuit, and dynamic stability analyses. The power flow analysis identified thermal or voltage limit violations resulting from the interconnection, and identified Network Upgrades required to deliver the proposed generation to PSCo loads. The short circuit analysis identified circuit breaker short circuit capability limits that could be exceeded because of the Interconnection and the delivery of the proposed generation to PSCo loads. The dynamic stability analysis identified any limitations associated with each portfolio due to angular instability of the system for regional disturbances.

PSCo adheres to NERC / WECC Reliability Criteria, as well as internal Company criteria for planning studies. During system intact conditions, criteria are to maintain transmission system bus voltages between 0.95 and 1.05 per-unit for system normal conditions, and steady state power flows within 1.0 per-unit of all elements thermal (continuous current or MVA) ratings. Operationally, PSCo tries to maintain a transmission system voltage profile ranging from 1.02 per-unit or higher at generation buses, to 1.0 per-unit or higher at transmission load buses. Following a single contingency element outage, transmission system steady state bus voltages must remain within 0.90 per-unit to 1.10 per-unit. Power flows over 1.0 per-unit of the elements continuous thermal ratings are monitored and evaluated to determine potential network upgrades. The NERC / WECC Planning Standards for System Performance were also followed for the stability analysis. In the WECC Disturbance-Performance criteria, for the loss of a single element (line or transformer), the maximum allowed voltage dip after fault clearing is 25% for load buses. This dip cannot exceed 20% for more than 20 cycles. The allowed post-transient voltage deviation, 1 to 3 minutes after the fault, is 5% for all buses. In addition, the frequency at any bus cannot be below 59.6 Hz for more than 6 cycles.

The proposed transmission for delivery alleviates potential impacts to regional utilities in the area of study that would be associated with the interconnections. These results have been shared with Aquila, Arkansas River Power Authority, Colorado Springs Utilities, Platte River Power Authority, Tri-State Generation and Transmission, and Western Area Power Administration.

At the time of this study, there were no active LGIP requests in the PSCo Generator Interconnection Queue. Therefore, this study did not have to consider any other higher queued projects.

III. Modeling

Studies were conducted using 2008 and 2010 system models. As seen in Table 1, the commercial in-service dates for most of the bids indicated various months in 2007. A few bids had options to provide some or all of their generation by the summer of 2008. To simplify the analysis, most studies were performed using 2008 models. The portfolios that included G031 needed to be evaluated with consideration of the planned 750-MW Comanche 3 unit, due to the proximity to that project. Therefore, a 2010 model was also used to analyze those portfolios.

A. 2008 Peak Load

The 2008 summer peak case was built from the WECC-approved 2007HS2A base case. The PSCo powerflow area load was derived from the 2008 summer peak forecast provided by PSCo's Regulated Risk Service & Generation Modeling Group on April 26, 2005. For the peak load models, the PSCo powerflow area load was about 7550 MW, and the Western RM load was about 4500 MW. In order to evaluate the capabilities of the system for firm transfer levels, the case was modified to simulate high TOT 3 and north to south system flows. Modifications resulted in increasing TOT 3 flows from 1,185 MW north-to-south to 1,445 MW north-to-south and increased the TOT7 flow from 565 MW north-to-south to 763 MW north-to-south.

B. 2008 Minimum Load

The 2008 Spring Minimum Load case was based on the WECC-approved 2006LSP2-SA base case. Since actual data shows that maximum levels of wind generation occurs during lighter load periods, the purpose of the minimum load cased was to evaluate the ability of the system to accommodate full wind penetration. The PSCo loads in the 2008 Spring power flow case were modeled by using historical data for the spring system minimums, and then making adjustments for load growth. The generating schedule applied was such that all gas-fired generation except the generators at the Rocky Mountain Energy Center (RMEC) were off line, the wind generation was assumed to be at maximum output, and the remaining PSCo generation in the case is coal-fired. For the minimum load models, the PSCo powerflow area load was approximately 3000 MW.

C. 2010 Peak Load

The 2010 peak load case was built from the WECC-approved 2009HS1A base case. The PSCo powerflow area load was derived from the PSCo forecast for 2010 summer peak conditions, as provided by PSCo's Regulated Risk Service & Generation Modeling Group. A representative generation dispatch was used to serve the load change in the PSCo control area. The Comanche 750-MW Generation Project with associated transmission upgrades was included in the 2010 models. In order to evaluate the capabilities of the system for firm transfer levels, the case was modified to simulate high south to north transfers from southern Colorado to the Denver-metro area.

D. Dynamic Modeling

The WECC master database for dynamics data was used as a basis for this analysis. All machines were represented by the most recently developed dynamic models available for the machines in service or proposed. Expected and/or typical data submitted by individual resource bidders was used to model new generation resources. The data was reviewed at a cursory level for reasonableness. Non-disturbance cases were modeled to verify that dynamics modeling would initiate properly and to establish good benchmarks for performance.

IV. Steady State Results

The steady-state analysis evaluated the impact that the addition of a portfolio of resources would have on the existing transmission system compared to benchmark performance using existing generating resources available to PSCO. This process utilized contingency analysis to evaluate transmission system behavior with all facilities in service and its response under single contingency (N-1) conditions. The impacts of these portfolio resources were measured in terms of overloaded facilities or voltage changes outside of allowable boundaries.

The steady state analysis revealed several network upgrades that would be required to accommodate the various portfolios of generation. The study revealed some commonality in the recommendations for the portfolios. Some network upgrade requirements result from a particular project; others are from a subset of projects from each portfolio. Rather than describe the results of each portfolio, and to avoid some redundancy, the following sections describe each network upgrade.

A. Spruce – Smoky Hill 230 kV Transmission Uprate

This study showed that for all portfolios, this path exhibited the potential for significant contingency overloads. The overloads were most severe for portfolios that included project G025 at Spruce. However, the other portfolios also exhibited unacceptable contingency loadings. Presently, there are two 230 kV circuits between the Smoky Hill and the Spruce substations, residing on double-circuit transmission towers. The circuits were thought to have a continuous thermal rating of about 627 MVA. However, recent investigations into the PSCo transmission system have resulted in de-rating the lines to about 478 MVA due to clearance and terminating equipment limitations. The most severe contingency is the loss of one of the Spruce – Smoky Hill 230 kV circuits, leading to unacceptable loading on the remaining parallel circuit. The overloads ranged from about 70% to 91%, corresponding to 25% to 45% higher loadings than in the benchmark case.

It is recommended that each circuit of the Spruce – Smoky Hill double-circuit 230 kV transmission, and termination equipment as needed, be upgraded to achieve a continuous rating of 800 MVA for each of the portfolios studied.

B. Smoky Hill – Jordan 230 kV Transmission Uprate

This study showed that for all portfolios, this path exhibited the potential for significant contingency overloads. The overloads were most severe for portfolios that included project G025 at Spruce. However, the other portfolios also exhibited unacceptable contingency loadings. There are three series transmission elements that make up the 230 kV transmission from Smoky Hill to Jordan. Smoky Hill – Meadow Hill is rated at 328 MVA. Meadow Hill to Orchard, and Orchard to Jordan are rated at 346 MVA. Studies showed that for certain contingencies, the loadings on the Smoky Hill – Jordan 230 kV path increased from 15% to 35% over the benchmark conditions depending on the portfolio. Overloads ranged from 16% to 69% of the continuous ratings of the line segments.

It is recommended that the entire 230 kV transmission line between Smoky Hill and Jordan, and termination equipment as needed, be upgraded to achieve continuous rating of 558 MVA.

C. St. Vrain – Valmont/Leggett 230 kV Transmission Uprate

For all portfolios that included project G029, near Frederick, there were contingency overloads on the 230 kV transmission between St. Vrain and Niwot, and St. Vrain and Valmont. Presently, there are two 230 kV circuits between the St. Vrain and Leggett/Valmont substations, residing on double-circuit transmission towers. The circuits have a continuous thermal rating of 346 MVA. Initial studies showed benefits to interconnecting project G029 to the St. Vrain – Niwot 230 kV line. The most severe contingency is the loss of one of the 230 kV circuits, leading to unacceptable loading on the remaining parallel circuit. For portfolios with G029, contingency overloads ranged from 29% to 36% of the continuous ratings, which are about 25% higher than benchmark conditions.

It is recommended that the 230 kV double-circuit transmission between St. Vrain and Leggett/Valmont, and termination equipment as needed, be upgraded to achieve a continuous rating of 525 MVA for all portfolios that contain G029.

D. Midway – Waterton 345 kV Addition and Associated Upgrades

For all portfolios that included project G031, near Midway, there were significant contingency overloads on the transmission systems that belong to Colorado Springs Utilites (CSU), Aquila, and Mountain View Electric Association. To alleviate the potential overloads and accommodate G031, the following network upgrades are recommended:

1. Establish a 345 kV transmission circuit Between Midway and Waterton substations.
2. Replace the two 100 MVA 230/115 kV autotransformers at Waterton substation with 280 MVA units.
3. Increase the rating of the Waterton – Littleton 115 kV line from 135 MVA to 217 MVA.

E. Cherokee – Silver Saddle 230 kV Transmission Uprate

For all portfolios that included project G043, interconnecting at the Silver Saddle substation, there were contingency overloads on the 326 MVA rated, 230 kV transmission line between Cherokee and Silver Saddle substations. The most severe contingency was loss of the Cherokee Unit #4, which caused overloads of 38% - 46% on the Cherokee – Silver Saddle 230 kV line. The contingency loadings were 41% - 49% higher than with benchmark conditions.

It is recommended that the 230 kV transmission line between Silver Saddle and Cherokee be modified and termination equipment replaced as needed, to achieve a continuous rating of 495 MVA.

F. Valmont 230/115 kV Transformer Addition

For all portfolios that included project G004, interconnecting at the Plains End switching station, there were contingency overloads on the 280 MVA rated, 230/115 kV autotransformer at Valmont. The most severe contingency is the loss of the Plains End - Lookout 230 kV line. That contingency caused overloads of about 23% on the existing transformer, or 27% more than for benchmark conditions.

To alleviate the contingency overloads, it is recommended that a second 280 MVA 230/115 kV autotransformer be added at Valmont.

G. Network Upgrades Summary

Table 2 summarizes the network upgrades identified from powerflow studies. A simple map showing the general vicinities of the upgrades is shown in Section IX.

Table 2

Network Upgrades		Portfolio								
		A	B	C	D	E	F	G	H	I
Spruce - Smoky 230 kV Uprate	1	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43
Smoky Hill - Jordan 230 kV Uprate	2	$0.98	$0.98	$0.98	$0.98	$0.98	$0.98	$0.98	$0.98	$0.98
St.Vrain – Valmont/Leggett 230 kV Uprate	3	$2.75	$2.75	$2.75	$2.75			$2.75	$2.75	$2.75
Cherokee - Silver Saddle 230 kV Uprate	4	$0.95		$0.95	$0.95	$0.95	$0.95			$0.95
Valmont 230/115 280 MVA Transformer Addition	5	$3.82						$3.82		$3.82
Midway – Waterton 345 kV Addition and Associated Upgrades	6	$28.50	$28.50	$28.50	$28.50	$28.50	$28.50			
Total Cost (Millions)		**$34.66**	**$35.61**	**$35.61**	**$32.86**	**$32.86**	**$9.98**	**$6.16**	**$10.93**	**$7.11**

V. Transient Stability Results

The objective of this assessment was to review system performance with the addition of the new thermal and wind resources within each of the portfolios and, if necessary, identify options that could improve system stability during periods of system stress. Stability analysis was performed for the summer peak condition and for light load conditions to determine the impact of the existing and proposed thermal and wind projects on system performance at relatively extreme system conditions within the study area. Over fifty disturbances were modeled for each portfolio. Disturbances close to the interconnection points of the various projects in each portfolio were simulated to evaluate the transient stability of each of those projects. In addition, several general system disturbances were also modeled. All of the studied faults were three-phase faults, with most on the 230-kV system.

Contingencies were simulated on the 2008 summer peak cases without any portfolio resources and then repeated on the cases for each portfolio to identify impacts associated with any of proposed projects. Additionally, the 2010 summer peak period was studied for those portfolios that included resource additions after 2008. Since wind generation is expected to represent a more significant proportion of generating capacity in the future, stability analysis was also performed for minimum load conditions in 2008. Since the interconnection point for some of the proposed projects are a tap of one or more lines, additional faults were modeled to enable comparisons of the portfolio cases with the behavior of the existing system.

A. 2008 and 2010 Peak Load Models

For all contingencies except one, the system exhibited a stable response with positive damping. The exception was for a fault at Boone, and subsequent tripping of the Boone – Lamar 230 kV circuit. However, this is an existing condition, and operating procedures are in place to trip the Lamar DC Tie and the existing wind generation as needed.

In a number of faults that were studied, clearing the fault will also result in the disconnection of generation from the transmission system. These situations include opening a radial transmission circuit or a single transformer that connects the generator to the system. However, none of these disturbances resulted in system instability.

The following subsections describe some noteworthy observations of the stability analysis.

1. Boone – Lamar 230 kV Disturbance
   The only fault that causes the transient voltage deviation to exceed 20% was a fault at the Lamar end of the Boone – Lamar 230 kV circuit. For all of the other faults in the portfolios studied, the largest transient voltage deviations for all monitored buses are well within the transient criteria.

2. Laramie River – Ault 345 kV Disturbance
   For a disturbance that modeled a fault at Laramie River Station (LRS) and the subsequent clearing of the fault by opening the LRS – Ault 345 kV line, the voltage at Ponnequin was about 6% below the pre-fault level for all portfolios except Portfolio F. However, power flow studies showed that once tap-changing transformers and switched capacitors have the chance to operate, the voltage at Ponnequin would increase to be within the acceptable criteria levels. In the base case, the voltage at Ponnequin was about 5% below the prefault level for this contingency.

3. G029(Spindle) – Isabelle 230 kV Disturbance
   For a disturbance that modeled a fault on the G029 – Isabelle 230 kV circuit, the voltage at the Isabelle 230 kV bus was about 5.5-5.7% below the pre-fault level for

those portfolios that included G029. The power flow studies showed that even after the tap-changing transformers and switched capacitors have the chance to operate, the voltage at Isabelle will not increase to be within the acceptable criteria levels. In the bench mark model, the voltage at the Isabelle 230 kV bus was about 4% below the pre-fault level. Since this is within the disturbance criteria, this violation is due to the portfolio generation. From power flow analysis, the voltages at Isabelle, Niwot, Leggett, and Lookout all decline with the outage of the G029 – Isabelle 230 kV circuit, with the largest drop occurring at Isabelle. While the impacts of this contingency are within the steady state analysis criteria, they are not within the WECC disturbance criteria. The addition of reactive support at the Niwot 230 kV bus, or other locations between Lookout and Isabelle on this 230 kV line, would help to increase voltage levels in this area under the identified contingency. When 60 MVARs of switched capacitors were added at Niwot, the post transient voltage deviation at Isabelle was about 3.7%.

Due to the breaker configurations on the St. Vrain - Niwot 230 kV line, in actual practice, a fault on the G029 – Isabelle circuit would result in the entire section between G029 and Niwot being taken out of service. However, voltages at Niwot exhibited similar performance to Isabelle.

4. Wind Project Faults

For a fault at Pawnee that is cleared in 4 cycles, the voltage at the W009 project was above 0.60 pu. Similar results were seen at the W022 wind farm for a fault at the interconnection point for W022 near RMEC. Projects W009 and W022 will have low voltage ride through capability and are interconnected through long transmission lines. Therefore, system disturbances that are not on the radial lines to those projects should not impact their operation and they should remain online during peak load periods.

A fault and subsequent loss of either the W009 or W022 facility and its respective radial transmission line does not have any impact on the stability of the system other than the loss of generation and the resultant change in machine angles. There does not appear to be any issues with voltages at the proposed wind farms based on the use of GE turbines as proposed and the long transmission lines.

B. 2008 Minimum Load Model

All disturbances tested except for three were found to be stable and well damped, and low voltage ride-through constraints met. Two of these disturbances are associated with the existing Ridge Crest wind farm at Peetz, and the third is concerned with the Boone – Lamar 230 kV circuit. It should be noted that in some cases the low voltage constraint conditions are such that the wind machines should shut down, and they did. This was found to be true for the Spring Canyon and Ponnequin cases where the fault applied was at the project’s interconnection bus. Testing of the ability to “ride through” fault conditions at more remote buses were found to be successful in all cases, including for the interconnection points for the W022 and W009 projects. The instability of the Ridge Crest Project is tied to the vintage of the NEG Micon 900/52 wind machines. Due to the breaker configuration on the Sidney – Sterling 115 kV line, in actual practice, a fault on that line would result in the entire line and the Ridge Crest being taken out of service. Therefore there would be no impact to the surrounding transmission system.

C. Network Upgrades from Stability Summary

Studies revealed that any portfolio that contained G029 would require approximately 60 MVARs of shunt caps at or near the Niwot 230 kV bus. Table 3 summarizes the portfolio costs.

Table 3 Network Upgrades Identified from Stability Studies

Network Upgrades	Portfolio								
Breaker Voltage	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**
60 MVAR Shunt Capacitors at or near Niwot (Millions)	**$0.70**	**$0.70**	**$0.70**			**$0.70**	**$0.70**	**$0.70**	**$0.70**

VI. Short Circuit Results

The short circuit analysis consisted of faulting buses at or near the points of interconnection of the portfolio generation. Three-phase and single-line to ground faults were evaluated and the three-phase faults were found to be more severe. Breakers that were approaching their maximum fault duty were documented. Table 4 summarizes the estimated cost for breakers that have been identified for replacement. In some locations, other viable options to breaker replacement continue to be evaluated and may be described in subsequent facilities studies.

Table 4 Short Circuit Results – Number of Breakers and Cost of Replacement

Breaker Replacement	Portfolio								
Breaker Voltage	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**
115 kV (Number to Replace)	13	13	12	13	12	13	13	12	12
230 kV (Number to Replace)	8	9	6	12	15	7	7	4	4
Total Cost (Millions)	**$3.80**	**$4.01**	**$3.24**	**$4.61**	**$3.84**	**$3.61**	**$3.61**	**$2.84**	**$2.84**

VII. PSCo Cost Estimates and Assumptions

A. Network Upgrades for Interconnection (Figures are shown in Section VIII)

1. W009

Element	Description	Cost ($ Millions)
Pawnee Switching Station	Upgrade Pawnee 230kV substation to interconnect the facility. The new equipment required includes: • Two (2) 230 kV 3000 amp 40 kA circuit breakers	**$1.148**
	Transmission Line Tap Structures and Line	**$0.077**
	Siting & Land Rights	**N/A**
Total Cost	**Estimated Costs for Network Upgrades for Interconnection**	**$1.225**
Time Frame	**Months Estimated for Construction**	**12 months**

2. W014

Element	Description	Cost ($ Millions)
Colorado Green Switching Station	Install new metering equipment required to separate the existing and additional generation. The equipment required includes: • Two (2) 230 kV metering units	**$0.210**
	Siting & Land Rights	**N/A**
Total Cost	**Estimated Costs for Network Upgrades for Interconnection**	**$0.210**
Time Frame	**Months Estimated for Construction**	**6 months**

3. W022

Element	Description	Cost ($ Millions)
New Switching Station	Construct a 230kV substation that will sectionalize only one RMEC – Green Valley 230 kV line and interconnect the Customer's 230 kV line to the Project. The equipment required includes: • Site development and land • Control building • Three (3) 230 kV 3000 amp 40 kA circuit breakers	**$2.916**
	Transmission Line Tap Structures and Line	**$0.077**
	Siting & Land Rights	**$0.298**
Total Cost	**Estimated Costs for Network Upgrades for Interconnection**	**$3.291**
Time Frame	**Months Estimated for Construction**	**24 months**

4. G004

Element	Description	Cost ($ Millions)
Plains End Switching Station	Upgrade Plains End 230kV substation to interconnect the facility. The equipment required includes: • One (1) 230 kV 3000 amp 40 kA circuit breaker • 230 kV metering units	**$0.612**
	Transmission Line Tap Structures and Line	**$0.077**
	Siting & Land Rights	**N/A**
Total Cost	**Estimated Costs for Network Upgrades for Interconnection**	**$0.689**
Time Frame	**Months Estimated for Construction**	**12 months**

5. G020

Element	Description	Cost ($ Millions)
Upgrade Switching Station	Upgrade Fort Lupton 230kV switchyard to interconnect the facility. The equipment required includes: • 230kV metering units	**0.218**
	Transmission Line Tap Structures and Line	**N/A**
	Siting & Land Rights	**N/A**
Total Cost	**Estimated Costs for Network Upgrades for Interconnection**	**0.218**
Time Frame	**Months Estimated for Construction**	**6 months**

6. G022

There are no PSCo costs for G022

7. G025

Element	Description	Cost ($ Millions)
Upgrade Spruce Switching Station	Upgrade Spruce 230 kV substation to interconnect the facility. The equipment required includes: • Two (2) 230 kV 3000 amp 40 kA circuit breakers • 230 kV metering units	**$1.192**
	Transmission Line Tap Structures & Tap	**$0.114**
	Siting & Land Rights	**N/A**
Total Cost	**Estimated Costs for Network Upgrades for Interconnection**	**$1.306**
Time Frame	**Months Estimated for Construction**	**12 months**

8. G029

Element	Description	Cost ($ Millions)
New PSCo Spindle Switching Station	Construct Spindle 230kV substation to interconnect the facility. The equipment required includes: • Three (3) 230 kV 3000 amp 40 kA circuit breaker • Site development and land • Control building	**$2.644**
	Transmission Line Tap Structures & Tap	**$0.077**
	Siting & Land Rights	**$0.317**
Total Cost	**Estimated Costs for Network Upgrades for Interconnection**	**$3.038**
Time Frame	**Months Estimated for Construction**	**24 months**

9. G031

Element	Description	Cost ($ Millions)
New PSCo 345 kV Switching Station	Construct a new PSCo 345 kV ring bus substation that will sectionalize the PSCo Comanche – Daniels Park 345 kV operated line and interconnect the Customer's 345 kV line to the Project. The equipment required includes: • Site development and land • Control building • Four (4) 345 kV 3000 amp 40 kA circuit breakers	**$7.479**
	Transmission Line Tap Structures & Tap	**$0.115**
	Siting & Land Rights	**$0.450**
Total Cost	**Estimated Costs for Network Upgrades for Interconnection**	**$8.044**
Time Frame	**Months Estimated for Construction**	**27 months**

10. G043

Element	Description	Cost ($ Millions)
Upgraded Silver Saddle Switching Station	Upgrade Silver Saddle 230kV substation to interconnect the facility. The new equipment required includes: • Two (2) 230 kV 3000 amp 40 kA circuit breakers	**$1.036**
	Transmission Line Tap Structures & Tap	**$0.077**
	Siting & Land Rights	**N/A**
Total Cost	**Estimated Costs for Network Upgrades for Interconnection**	**$1.113**
Time Frame	**Months Estimated for Construction**	**12 months**

B. PSCo Network Upgrades for Delivery Cost Estimates (Section IX shows a general geographic depiction of the upgrades)

1. Spruce – Smoky Hill

Facility	Description	Cost $ Millions
Spruce Substation	No changes required	**N/A**
Smoky Hill Substation	Modify the Smoky Hill Substation to allow an 800 MVA continuous rating on the Spruce – Smoky Hill 230 kV transmission. The following equipment will be required: • Five (5) 230 kV 3000 amp 40 kA circuit breakers	**$2.237**
Time Frame	**Months - Substation**	**12 months**
Transmission	Modify the existing 230 kV transmission line between Smoky Hill and Spruce substations to achieve an 800 MVA continuous rating. • Add extensions on tangent structures	**$0.195**
Time Frame	**Months - Transmission**	**4 months**
Siting, Permitting and Acquisition	Siting and Land Rights activities including siting study, acquisition & permitting.	**N/A**
Time Frame	**Months– S & LR**	**N/A**
Total Cost	**Total Estimated Cost for Network Upgrades for Delivery**	**$2.432**
Time Frame	**Months Estimated for Construction**	**12 months**

2. Smoky Hill – Jordan

Facility	Description	Cost $ Millions
Meadow Hill Substation	Modify the Meadow Hill Substation to allow 558 MVA continuous rating on the Smoky Hill to Jordan 230 kV transmission. The following equipment will be required: • Replace one (1) 230 kV switch	**$0.050**
Orchard Substation	Modify the Orchard Substation to allow 558 MVA continuous rating on the Smoky Hill to Jordan 230 kV transmission. The following equipment will be required: • Replace three (3) 230 kV switch	**$0.150**
Time Frame	**Months - Substation**	**6 months**
Transmission	Increase the continuous rating of the Smoky to Jordan 230 kV transmission line to 558 MVA. The following equipment will be required: • Remove existing Qwest shield wire and bury new shield wire • Replace one (1) steel pole and lower street lights	**$0.760**
Time Frame	**Months - Transmission**	**6 months**
Siting, Permitting and Acquisition	Siting and Land Rights activities including siting study, acquisition & permitting.	**$0.02**
Time Frame	**Months– S & LR**	**2 months**
Total Cost	**Total Estimated Cost for Network Upgrades for Delivery**	**$0.980**
Time Frame	**Months– Network Upgrades**	**8 months**

3. St. Vrain – Valmont /Leggett 230kV Uprate

Facility	Description	Cost $ Millions
Ft. St. Vrain Switchyard	Modify the Fort St. Vrain Switchyard to allow 525 MVA continuous rating on the St. Vrain to Valmont/Leggett 230 kV double circuit transmission. The following equipment will be required: • Six (6) 230 kV 3000 amp 40 kA circuit breakers • 230 kV metering units	**$1.127**
Leggett Substation	Minor substation upgrades required to achieve the desired rating on the St. Vrain to Valmont/Leggett 230 kV double circuit lines: • Replace jumpers	**$0.024**
Time Frame	**Months - Substation**	**10 months**
Transmission	Increase the continuous rating of the St. Vrain to Valmont/Leggett 230 kV transmission line to 525 MVA. The following equipment will be required: • Replace/add cage extensions • Replace tangent poles and steel dead end structures	**$1.567**
Time Frame	**Months - Transmission**	**8 months**
Siting, Permitting and Acquisition	Siting and Land Rights activities including siting study, acquisition & permitting.	**$0.030**
Time Frame	**Months– S & LR**	**2 months**
Total Cost	**Total Estimated Cost for Network Upgrades for Delivery**	**$2.748**
Time Frame	**Months– Network Upgrades**	**12 months**

4. Cherokee – Silver Saddle 230kV Uprate

Facility	Description	Cost $ Millions
Cherokee Switchyard	Modify the Cherokee Switchyard to allow 506 MVA continuous rating on the Cherokee to Silver Saddle 230 kV transmission line. The following equipment will be required: • Two (2) 230 kV 3000 amp 50 kA circuit breakers	**$0.768**
Time Frame	**Months - Substation**	**12 months**
Transmission	Increase the continuous rating of the Cherokee to Silver Saddle 230 kV transmission line to 506 MVA. The following equipment will be required: • Replace/add cage extensions • Add one (1) Steel Structure	**$0.181**
Time Frame	**Months - Transmission**	**12 months**
Siting, Permitting and Acquisition	Siting and Land Rights activities including siting study, acquisition & permitting.	**N/A**
Time Frame	**Months– S & LR**	**N/A**
Total Cost	**Total Estimated Cost for Network Upgrades for Delivery**	**$0.949**
Time Frame	**Months– Network Upgrades**	**12 months**

5. Valmont 230/115 Transformer Addition

Facility	Description	Cost $ Millions
Valmont 230 kV Switching Station	Install a 2nd 230-115 kV 280 MVA autotransformer and associated equipment at Valmont switching station. The following equipment will be required: • One (1) 230-115 kV 280 MVA autotransformer • One (1) 230 kV 3000 amp 40 kA circuit breaker • Two (2) 115 kV 2000 amp 40 kA circuit breaker	**$3.819**
Time Frame	**Months - Transmission**	**16 months**
Siting, Permitting and Acquisition	Siting and Land Rights activities including siting study, acquisition & permitting.	**N/A**
Time Frame	**Months– S & LR**	**N/A**
Total Cost	**Total Estimated Cost for Network Upgrades for Delivery**	**$3.819**
Time Frame	**Months– Network Upgrades**	**16 months**

6. Midway – Waterton 345kV and Associated Transmission

Facility	**Description**	**Cost $ Millions**
Midway 345 kV Substation	Install a new 345kV substation, set up for a Breaker-and-Half configuration, which will interconnect with the existing Midway 230kV Substation via one 345/230kV autotransformer.	**$5.459**
Waterton 345 kV Substation	Install a new 345kV substation, set up for a Breaker-and-Half configuration, which will interconnect with the existing Waterton 230kV Substation via one 345/230kV autotransformer.	**$5.922**
Tarryall 230 kV Substation	Install new 230kV line terminal to sectionalize the 230kV Tarryall to Daniels Park 230kV transmission line at Waterton.	**$1.808**
Time Frame	**Months - Substations**	**18 months**
Waterton to Daniels Park New D/C 345kV Transmission Line	Install new double circuit 345kV constructed transmission line from the Waterton Substation to the Daniels Park Substation (approx. 9 miles). Bundled 954 kcmil "Cardinal" conductor on tubular steel poles with foundations. One circuit operated at 345kV and one operated at 230kV. New transmission line to be built within existing ROW	**$7.868**
Sectionalize the Tarryall to Daniels Park 230kV Trans. Line	Install necessary transmission line equipment to sectionalize the Tarryall to Daniels Park 230kV transmission line at Waterton Substation.	**$0.565**
Waterton 230kV Substation	Replace two 230/115kV autotransformers with new 230/115kV, 280 MVA autotransformers.	**$6.682**
Waterton to Littleton 115kV Trans Line	Minor transmission line upgrades to uprate 115kV transmission line to 217 MVA continuous rating.	**$0.090**
Time Frame	**Months - Transmission**	**14 months**
Siting, Permitting and Acquisition	Siting and Land Rights activities including siting study, acquisition & permitting.	**$0.108**
Time Frame	**Months– S & LR**	**18 months**
TOTAL	**Total Estimated Cost for Network Upgrades for Delivery**	**$28.502**
TOTAL	**Months– Network Upgrades**	**36 months**

C. Assumptions:

1. The estimated costs provided are "Scoping Estimates" with an accuracy of ± 30%.
2. All applicable overheads are included.
3. There is no contingency added to the estimates.
4. Estimates were not escalated and are in 2006 dollars.
5. PSCo (or its contractor) crews will perform all construction and wiring associated with PSCo-owned and maintained equipment.
6. Timeline and cost estimates assume permits, substation land, and right-of-way, as needed, will be available within typical costs and time frames..
7. The delivery infrastructure cost reflects the assumption that gas generation in PSCo's system was reduced to accommodate the wind generation projects in this portfolio. The delivery infrastructure cost would increase significantly if wind and gas generation were both accommodated.
8. It is assumed that a Certificate of Public Convenience and Necessity (CPCN) will not be required for any of the Network Upgrades for Interconnection. If the CPUC determines that a CPCN is required for any of the interconnections, the schedule will have to be re-evaluated to determine the extent of the resulting delays.
9. It is anticipated that a CPCN will be required from the CPUC for the network upgrades required for delivery for the Midway – Waterton 345 kV Transmission. The application for a CPCN will not be submitted until after an Interconnection Agreement has been executed.
10. It is assumed that a Certificate of Public Convenience and Necessity (CPCN) will not be required for any of the other (than Midway – Waterton) Network Upgrades for Delivery. If the CPUC determines that a CPCN is required for any of the recommended upgrades for Delivery, the schedules will have to be re-evaluated to determine the extent of the resulting delays.
11. Some public involvement will be required for the network upgrades required for delivery. Land use permits will be required from several local jurisdictions. Permitting could be difficult and potentially controversial.
12. All required transmission outages necessary to support construction will be obtained as needed.

VIII. Figures for Interconnection

Note that the "Customer Facilities" are shown to indicate the Point of Interconnection with PSCo, and may not fully represent the extent of the facilites.

Figure 1 Interconnection for W009

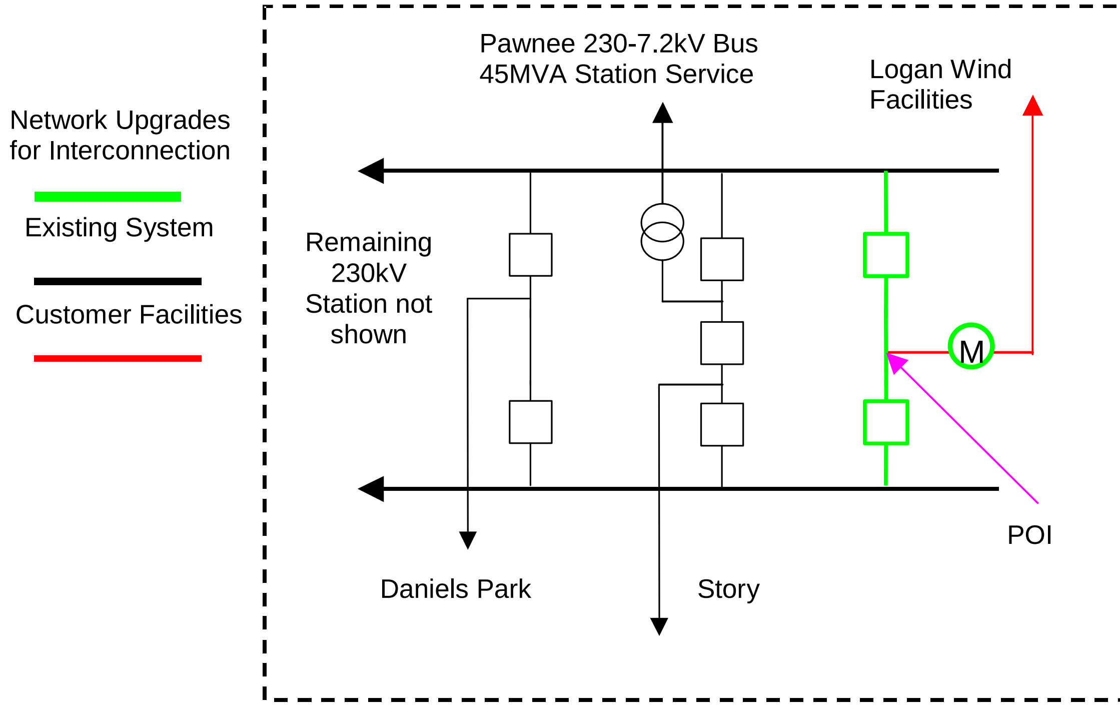


Figure 2 Interconnection W014

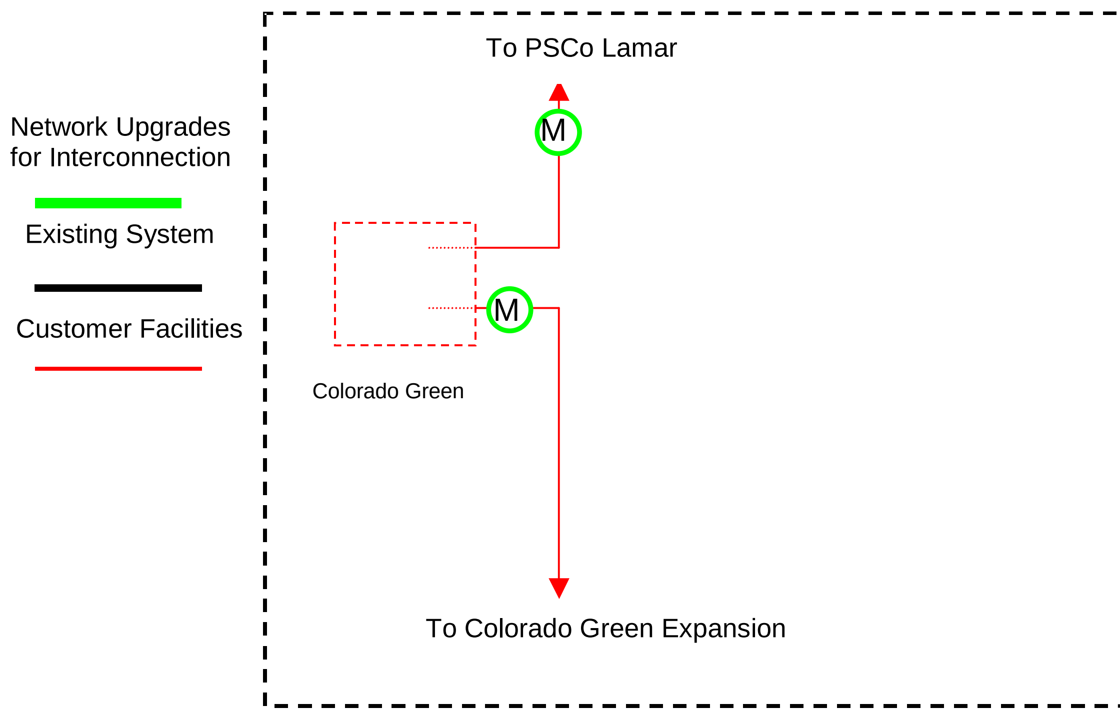


Figure 3 Interconnection for W022

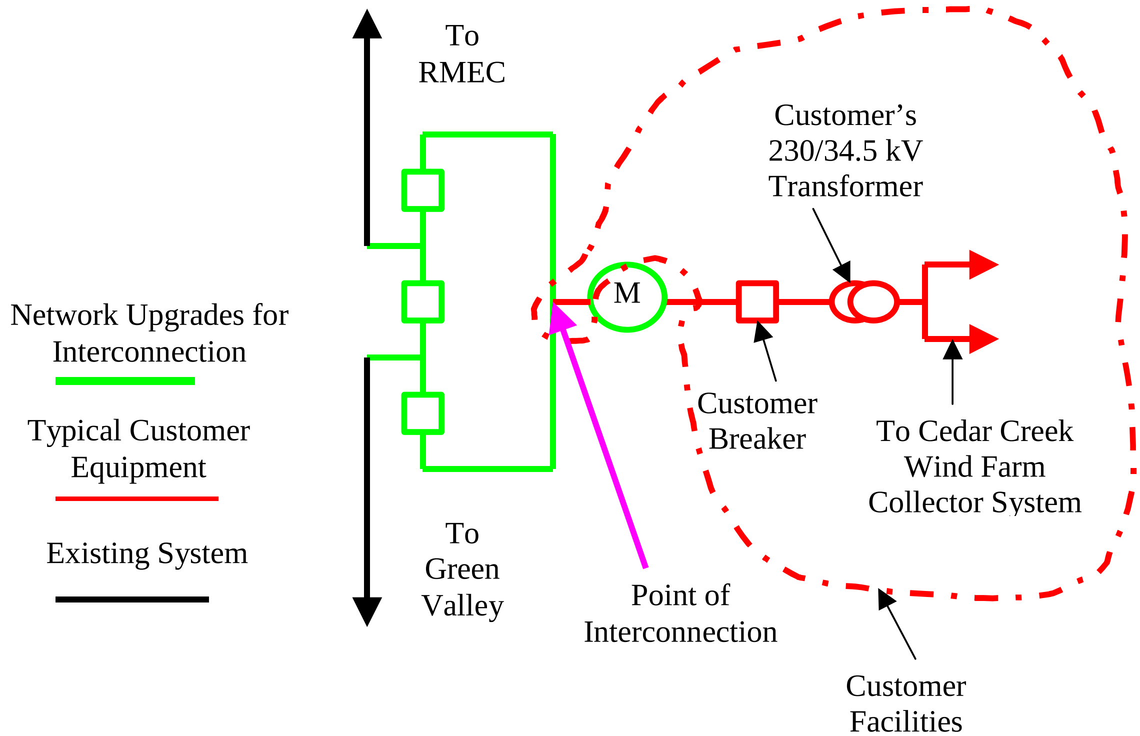


Figure 4 Interconnection for G004

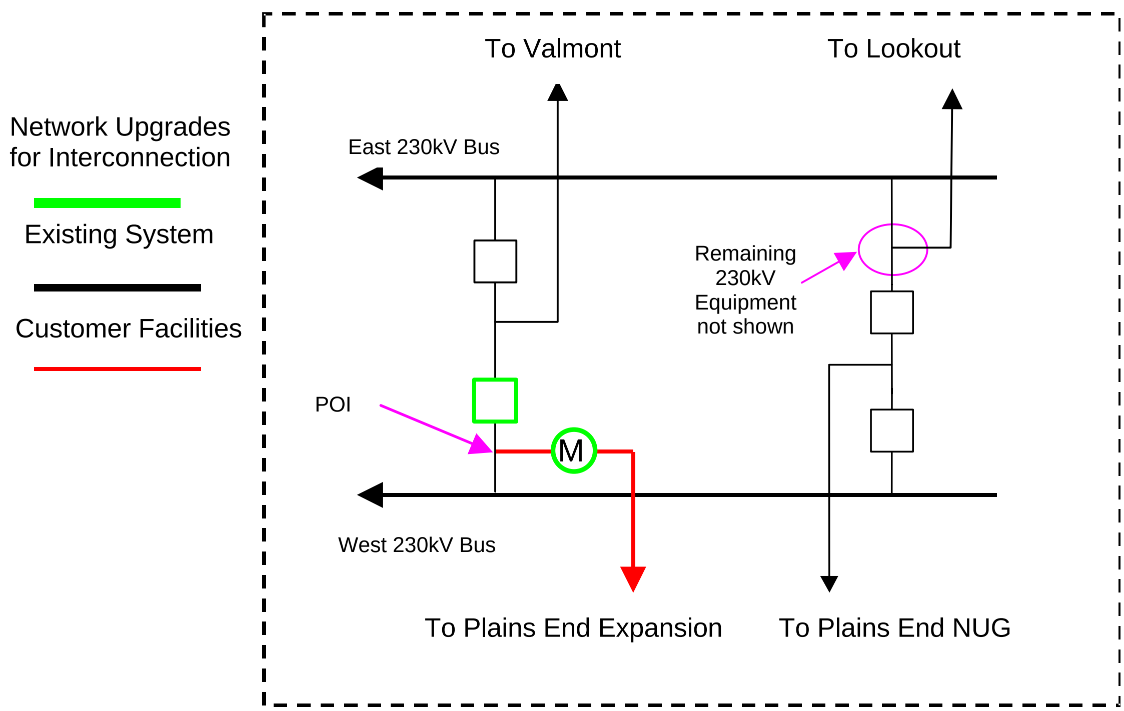


Figure 5 Interconnection for G020

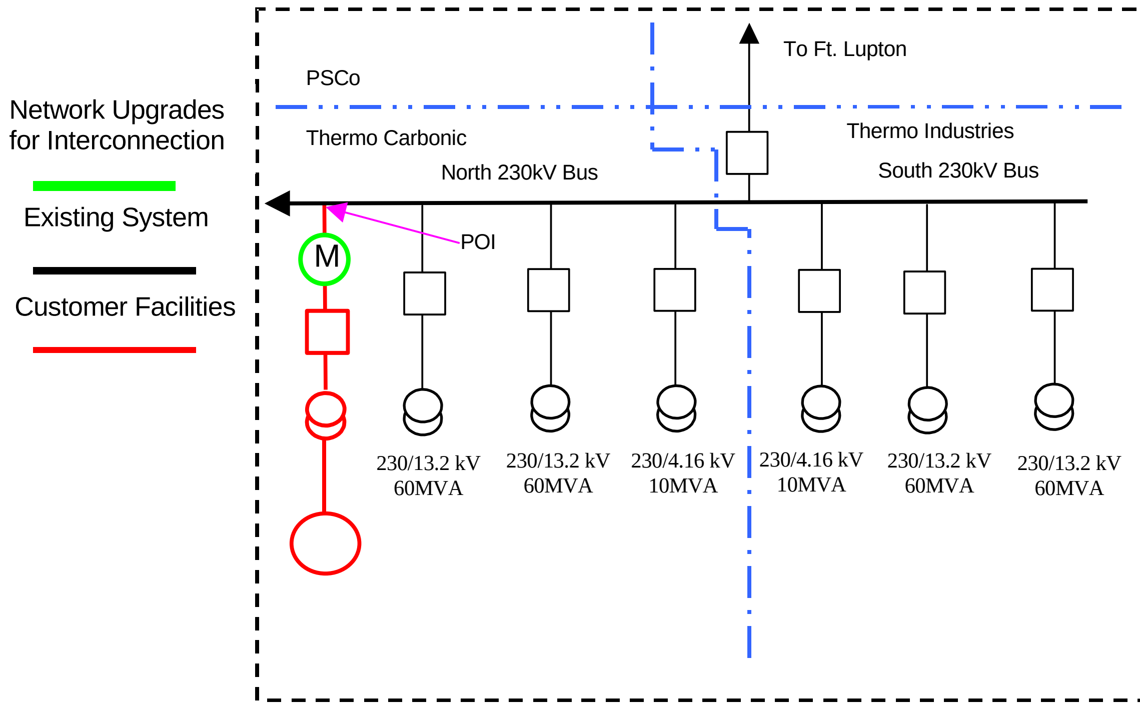


Figure 6 Interconnection for G025

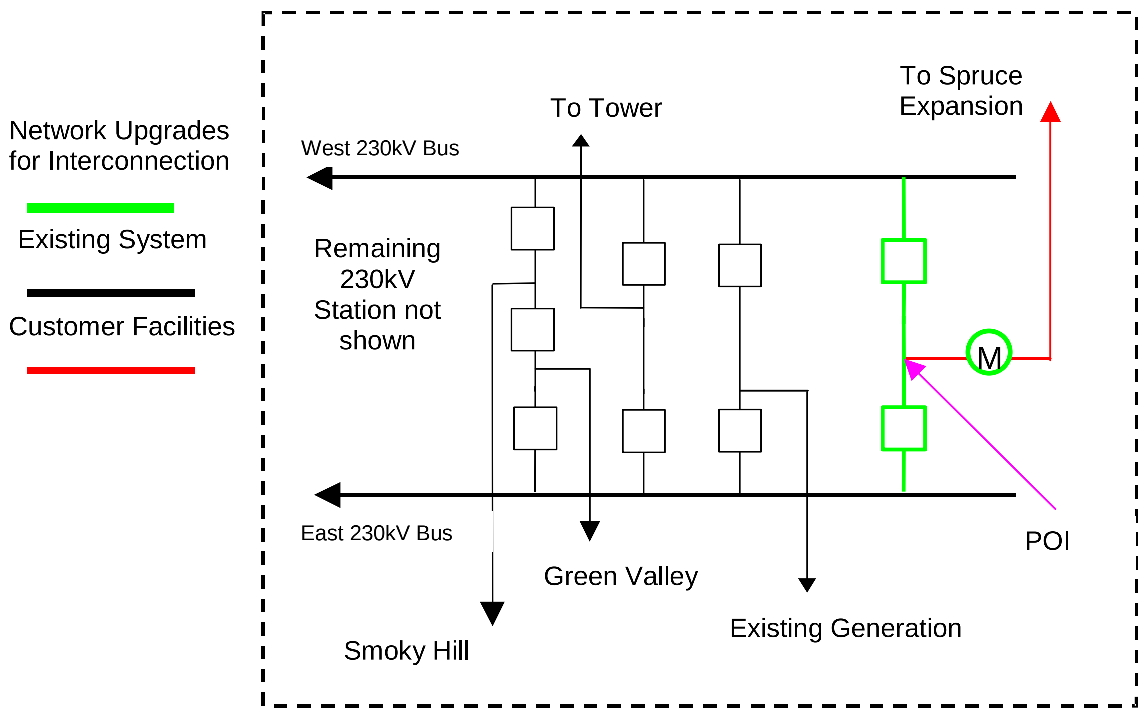


Figure 7 Interconnection for G029

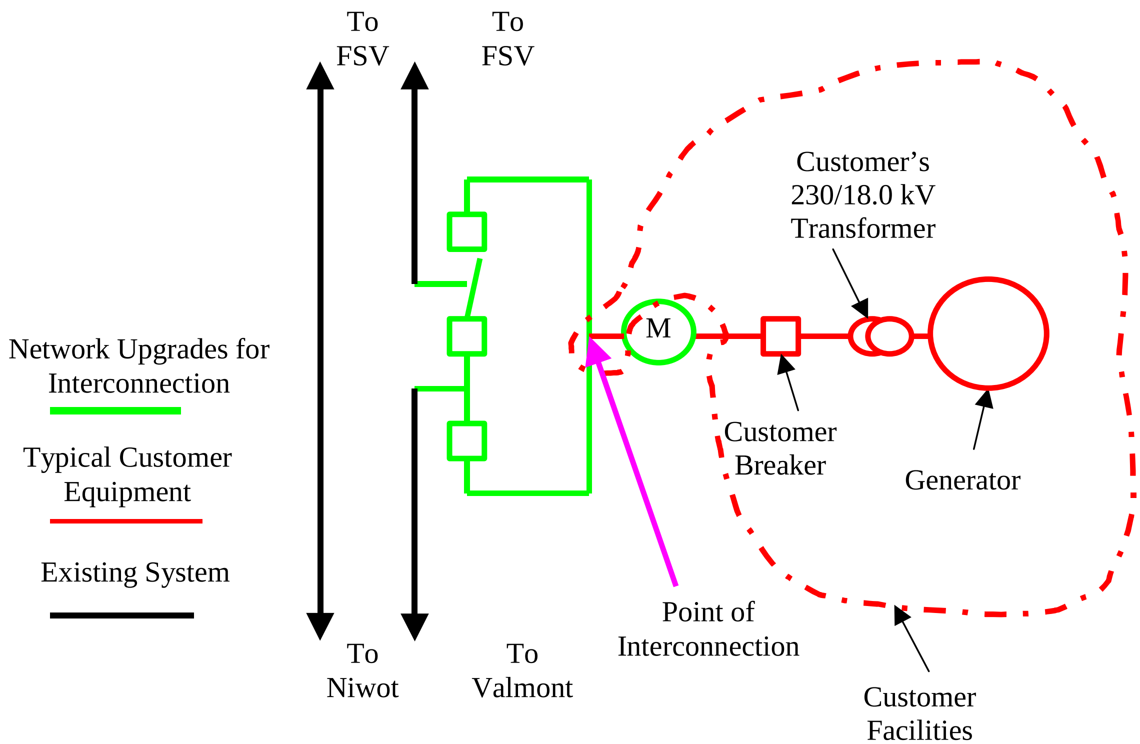


Figure 8 Interconnection for G031

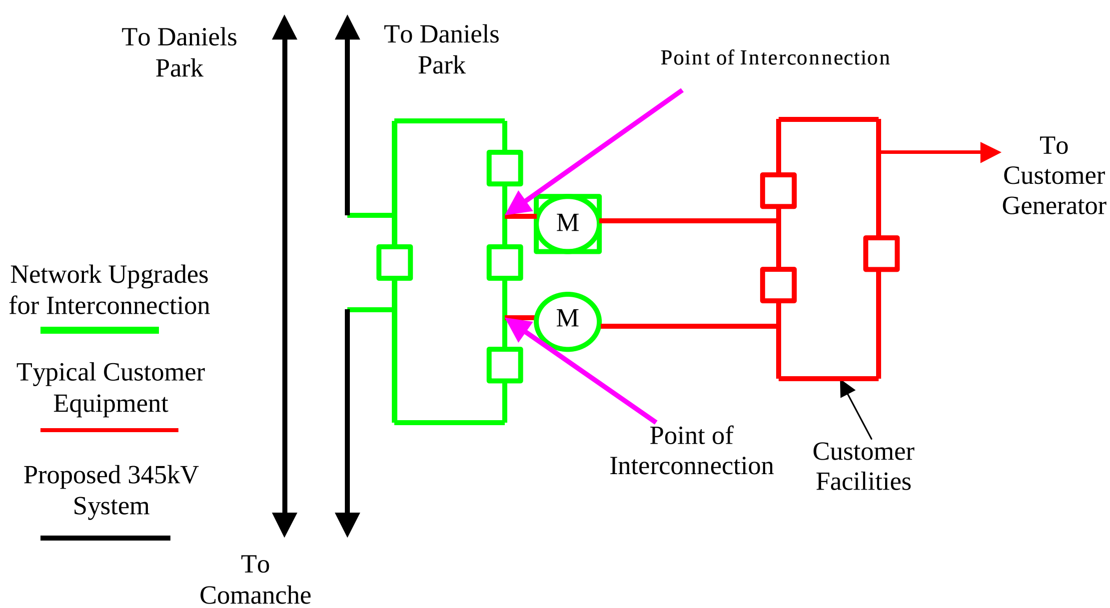
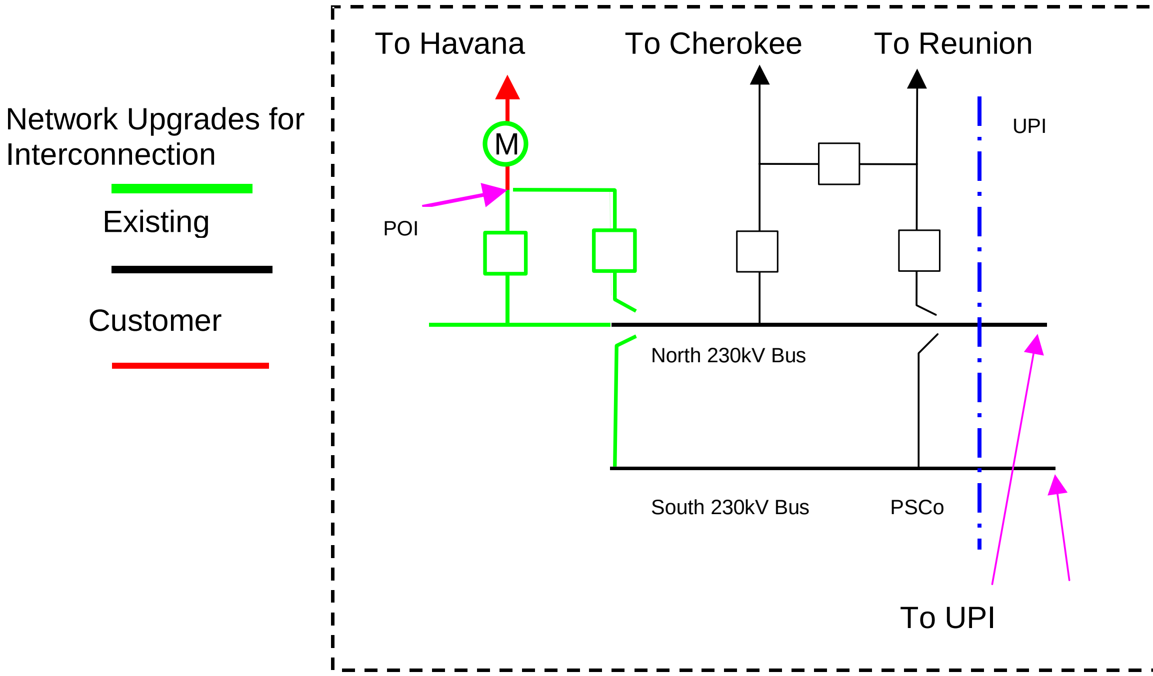


Figure 9 Interconnection for G043



IX. Figure for Network Upgrades for Delivery

Figure 10 General Locations of Network Upgrades for Delivery