GENERATOR INTERCONNECTION REQUEST

CLPT-G2
Interconnection System Impact Study

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TRANSMISSION PLANNING

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Executive Summary

A valid Large Generator Interconnection request was received on June 1, 2011 for a proposed generation facility under the guidance of the Cheyenne Light, Fuel & Power Open Access Transmission Tariff (OATT). The Proposed project consists of three (3) GE LM6000 gas turbine generators, each with a base load nominal gross output of 40 MW, for a total request of 120 MW. The Interconnection Customer (IC) elected to forgo the Feasibility Study and proceed with the System Impact Study. The requested commercial operation date of the project is June 1, 2014.

The study considered the impacts of the interconnection request by analyzing the transmission system before and after the interconnection of the proposed project. The study included steady state and transient stability analysis for both the 2015 peak summer and off-peak autumn load scenarios. The study also evaluated the impact of the interconnection request on the WECC-rated Path 36 (TOT3) located south of Cheyenne. Finally, the study also included short circuit analysis and provided a cost estimate and implementation schedule for Network Upgrades, if any, required to accommodate the proposed project.

All of the study results indicate that the proposed project will have a positive impact to the reliability and performance of the Cheyenne area transmission system and TOT3. In all scenarios and sensitivities the proposed project reduced the loading on the Cheyenne area 230/115 kV transformers, possibly delaying the replacement existing facilities and/or installation of new facilities. Additionally, initial analysis indicates that the proposed project may allow the TOT3 path rating to be increased. Any increase in the TOT3 rating will require additional analysis and review per the WECC path rating process.

The Network Upgrades required to interconnect the proposed project to the CLFP transmission system consist of a new 115 kV substation and a two (2) mile 115 kV double circuit line segment. The estimated total cost of the Direct Assigned and Network Upgrade facilities is $7,000,000. Of the total cost, the Direct Assigned facility cost is estimated to be $500,000.

All facilities required to interconnect the proposed project are expected to be in-service prior to the requested project in-service date of June 1, 2014.

1. Introduction

Cheyenne Light Fuel and Power (CLFP) owns certain transmission facilities with transmission service pursuant to a FERC approved OATT. A valid request was received from the Interconnection Customer (IC) on June 1, 2011 to provide interconnection service for the proposed generation facility under the guidance of the CLFP OATT Large Generator Interconnection Procedures (LGIP). The IC elected to forgo the Feasibility Study and proceed with the System Impact Study phase of the LGIP. The Proposed project consists of three (3) GE LM6000 gas turbine generators, each with a base load nominal gross output of 40 MW and will connect to the CLFP 115 kV system on the Skyline to Archer 115 kV line. The requested commercial operation date of the project is June 1, 2014.

1.1. Study Scope

The study considered the impacts of the interconnection request by analyzing the transmission system before and after the interconnection of the proposed project. The study included steady state and transient stability analysis for both the 2015 peak summer and off-peak autumn load scenarios. The study evaluated the impact of the interconnection request on the TOT3 WECC rated path located south of Cheyenne. Finally, the study also included short circuit analysis and provided a cost estimate and implementation schedule for suggested system upgrades to accommodate the proposed project.

1.2. Study Area

The study area included all CLFP transmission equipment as well as neighboring transmission system elements roughly bound by Laramie to the west, Ault to the south, Sidney to the east and Laramie River Station to the north.

1.3. Benchmark Cases

The peak load study scenario utilized a 2014 heavy summer study case which originated from the WECC website (14hs3sap.sav). This case was compiled in 2010.

The off peak load study scenario utilized a 2014 light autumn study case which originated from the WECC website (14la1sap.sav). This case was compiled in 2010.

Both benchmark cases were updated to reflect the transmission system for the 2015 timeframe. They were reviewed by area utilities to ensure accurate representation of regional area loads, resources, and transmission system configurations for that particular timeframe.

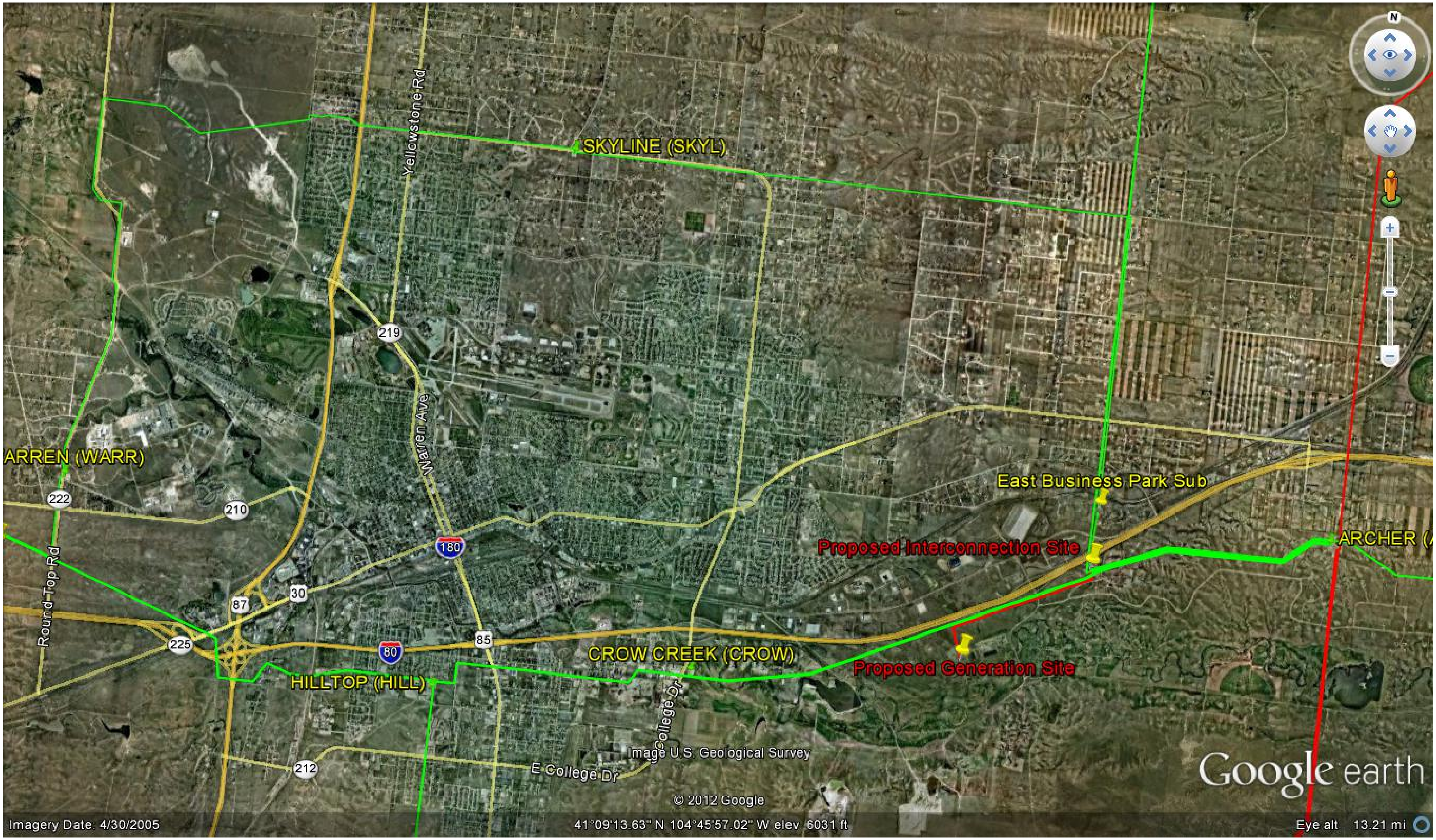
1.4. Sensitivity Case

A sensitivity scenario was run for both the 2015 peak and off peak study cases. This sensitivity looked at the effects the planned Tri-State Wayne Child project would have on the regional system. Simulations were first run with the Wayne Child project out of service followed by simulations with the project in-service.

1.5. Project Model

The proposed project consists of three (3) gas turbine units each with a nameplate rating of 71 MVA. This was represented in the power flow model as three separate 40 MW (gross) generating units; two of which are connected to a single 13.8 kV bus and sharing a single 13.8/115 kV generator step-up (GSU) transformer, and one unit on a separate 13.8 kV bus with a single 13.8/115 kV GSU transformer. The GSU transformers will interconnect to the CLFP system through a new 115 kV four (4) position ring bus substation. The new 115 kV substation was integrated into the CLFP system via a two (2) mile double circuit 115 kV line that will tie into the existing Archer-Skyline 115 kV line.

Figure 1: Google Earth Image Showing Proposed Generation Site and Interconnection Site



1.6. Interconnection Requirements

1.6.1. Reactive Power Requirements

The proposed project shall maintain a composite power delivery at continuous rated power output at the POI at a power factor within the range of 0.95 leading to 0.95 lagging, across the range of near 0% to 100% of facility MW rating, with the magnitude of VAR calculated on the basis of nominal POI voltage (1.0 p.u. V). The design shall consider the effects of step-up transformer reactance and voltage taps/turns ratios, and bus-fed auxiliary load. For this 120 MW rated facility the magnitude of reactive power capability required is +/- 39.4 MVAR at the proposed project's rated MW output level, as measured at the 115 kV POI. This would be the net MVAR required to be either produced or absorbed by the project. Based on the plant data supplied by the IC, the proposed project meets these requirements.

If BHC requires additional reactive power or voltage regulation to mitigate known system weaknesses, BHC will negotiate with the generator owner for any additional capability beyond the minimum requirements stated above.

Refer to BHC's *Facility Connection Requirements* document for details on excitation systems, voltage regulation, governor requirements, etc.

2. Study Methodology

This section summarizes the methods used to derive the power flow, transient stability, TOT3, and short circuit results.

2.1. Assumptions

The SIS was performed with the following assumptions:

- All existing and planned facilities and the effects of control devices and protection systems were accurately represented in the system model.
- Projected firm transfers were represented per load and resource updates.
- Existing and planned reactive power resources were modeled to ensure adequate system performance.
- There were no specific planned outages identified for the 2015 study period. A series of prior outages on facilities deemed to be most critical by the transmission planner was simulated to identify potential risks associated with such outages in the 2015 time frame. A list of the evaluated prior and forced outages is included in Appendix A.

The power flow analysis was performed with pre-contingency solution parameters that allowed adjustment of load tap-changing (LTC) transformers, static VAR devices including switched shunt capacitors and reactors, and DC taps. Post-contingency solution parameters allowed adjustment of DC taps and adjustment of switched shunt elements outside the study area. Area interchange control was disabled and generator VAR limits were applied automatically for all solutions. The solution method implemented for all cases was a fixed-slope decoupled Newton solution.

2.2. Reliability Criteria

The criteria described in this section are consistent with the NERC TPL Reliability Standards, WECC TPL – (001 thru 004) – WECC – 1 – CR ─ System Performance Criteria and Colorado Coordinated Planning Group's Voltage Coordination Guide.

2.2.1.Steady State Voltage Criteria

Under system intact conditions, steady state bus voltages must remain between 0.95 and 1.05 per unit. Following a Category B or C contingency, bus voltages must remain between 0.90 and 1.10 per unit. Pre-existing voltage violations outside the localized study area were ignored during the evaluation.

2.2.2.Steady State Thermal Criteria

All line and transformer loading must be less than 100% of their established continuous rating for system normal conditions (NERC/WECC Category A). All line and transformer loadings must be less than 100% of their established continuous or emergency rating under outage conditions (NERC/WECC Category B and C). Category D outages are to be evaluated for risk and consequence.

2.2.3.Transient Voltage and Frequency Criteria

NERC Standards require that the system remain stable and within applicable thermal ratings and voltage limits for Category A, B, and C disturbances. The *WECC Disturbance – Performance Table of Allowable Effects on Other Systems* states the following requirements:

- Category B: Any transient voltage dip must not exceed 25% at load buses or 30% at non-load buses. The dip also must not exceed 20% for more than 20 cycles at load buses. Frequency must not drop below 59.6 Hz for 6 or more cycles at a load bus.
- Category C: Any transient voltage dip must not exceed 30% at load buses or 30% at non-load buses. The dip also must not exceed 20% for more than 40 cycles at load buses. Frequency must not drop below 59.0 Hz for 6 or more cycles at a load bus.

2.3. Power Flow Analysis

All power flow analysis was conducted with version 30.3 of PTI's PSS/e software. Power flow results were monitored and reported for transmission system elements in the study area described in Section 1.2. Power flow analysis was used to evaluate the thermal and voltage performance of the system under Category A, B, and C disturbance conditions. Refer to Appendix A for a complete list of simulated prior and forced outages.

Thermal loading was reported when a modeled transmission element was loaded over 99% of its appropriate MVA rating modeled in the power flow database and when the incremental increase in loading from Pre-Project to Post-Project exceeded 2%. Transmission voltage violations were reported when the criteria described in Section 2.2.1 were not met.

2.4. Transient Stability Analysis

The objective of the transient stability analysis was to determine the ability of generators to remain in synchronism with one another by surviving the first swing of a disturbance such as a ground fault and subsequent breaker action on the transmission system. Transient stability also simulates the ability of the system as a whole to return to a given steady-state equilibrium after being moved away from it by a small perturbation.

Transient analysis was performed to evaluate the dynamic characteristics of the transmission system in proximity to the CLFP footprint following various disturbances. System loads were modeled using the WECC generic motor load penetration of 20 percent, with the under voltage load shedding function disabled to provide a worst-case representation of system performance. The transient stability contingencies were simulated out to 10 seconds to ensure a damped system response. The disturbances evaluated in the transient analysis were selected based on significance with respect to proximity to local generation. The 3-phase faults listed in Table 1 were simulated for the 2015 peak and off-peak scenarios.

Table 1: Simulated Transient Stability Disturbances

Disturbance Description	Faulted Bus	Cleared Element	Fault Duration (cycles)
Archer-Cheyenne 115	Archer 115	Archer-Cheyenne 115 kV line	5
Campstool-Archer 115	Campstool 115	Campstool-Archer 115 kV line	5
Campstool-East Business Park 115	Campstool 115	Campstool-East Business Park 115 kV line	5
Happy Jack-Cheyenne 115	Happy Jack 115	Happy Jack-Cheyenne 115 kV line	5
Happy Jack-Happy Jack Wind 115	Happy Jack 115	Happy Jack-Happy Jack Wind 115 kV line	5
Happy Jack-NCAR 115	Happy Jack 115	Happy Jack-NCAR 115 kV line	5
South Cheyenne-Swan Ranch 115	South Cheyenne 115	South Cheyenne-Swan Ranch 115 kV line	5
Archer-Ault 230	Archer 230	Archer-Ault 230 kV line	5
Archer-South Cheyenne 230	Archer 230	Archer-South Cheyenne 230 kV line	5
Archer-Stegall 230	Archer 230	Archer-Stegall 230 kV line	5
Cheyenne-South Cheyenne 230	Cheyenne 230	Cheyenne-South Cheyenne 230 kV line	5
Cheyenne-Snowy Range 230	Cheyenne 230	Cheyenne-Snowy Range 230 kV line	5
Snowy Range-Miracle Mile 230	Snowy Range 230	Snowy Range-Miracle Mile 230 kV line	5
South Cheyenne-Ault 230	South Cheyenne 230	South Cheyenne-Ault 230 kV line	5
South Cheyenne-North Park 230	South Cheyenne 230	South Cheyenne-North Park 230 kV line	5
Laramie River Station-Ault 345	Laramie River Station 345	Laramie River Station-Ault 345 kV line	4
Laramie River Station-Story 345	Laramie River Station 345	Laramie River Station-Story 345 kV line	4
Archer-Wayne Child 230*	Archer 230	Archer-Wayne Child 230 kV line	5
Cheyenne-Wayne Child 230*	Cheyenne 230	Cheyenne-Wayne Child 230 kV line	5
Archer TS-Story 345*	Archer TS 345	Archer TS-Story 345 kV line	4
Laramie River Station-Archer TS 345*	Laramie River Station 345	Laramie River Station-Archer TS 345 kV line	4

*These faults apply only to the Wayne Child sensitivity scenario

The following parameters were monitored in the 2015 peak and off peak scenarios to evaluate system stability performance:

- Rotor angle plots provide a measure for determining how the proposed generation unit would swing with respect to other generating units in the area. This information is used to determine if a machine would remain in synchronism or go out-of-step from the rest of the system following a disturbance.
- Bus voltage plots, in conjunction with the relative rotor angle plots, provide a means of detecting out-of-step conditions. The bus voltage plots are useful in assessing the magnitude and duration of post-disturbance voltage dips and peak-to-peak voltage oscillations. Bus voltage plots also give an indication of system damping and the level to which voltages are expected to recover in the steady state conditions.
- Bus frequency plots provide information on magnitude and duration of post-fault frequency swings with the new project in service. These plots indicate the extent of possible over-frequency or under-frequency excursions, which can occur due to an area's imbalance between load and generation.

2.5. TOT3 and 4A Analysis

The objective of the TOT3 analysis was to determine the impact, if any, that the proposed generation would have on the current TOT3 path rating. Generation was dispatched on either side of the TOT3 interface to increase the loading on the path to near the current WECC-approved rating with the proposed generation off-line. The proposed generation was then placed on-line and the analysis rerun to determine the impact the proposed generation had on the path.

A similar sensitivity analysis was also conducted to evaluate the impact the proposed generation would have with TOT3 and TOT4A rated paths simultaneously stressed.

New path ratings were not determined in the evaluation of the proposed generation. The objective was to identify whether the project had a positive impact on TOT3 and TOT4A or a negative impact.

2.6. Short Circuit Analysis

The objective of the short circuit analysis was to determine the impact, if any, that the proposed generation would have on system fault current. The existing fault current levels were identified and compared to post-project fault current levels to determine if existing fault interrupting devices exceeded their rating under simulated fault conditions as a result of the additional generation. It was assumed that all future fault interrupting devices would be designed to accommodate the fault levels identified in this analysis. The software used in this fault analysis was the ASPEN short circuit program.

3. Results

The objective of this study was to assess the reliability impacts of the proposed project on the transmission system and determine the network upgrades, if any, required to interconnect the proposed project. Detailed power flow and stability results are available upon request; these files are extremely large and would need to be broken up to be emailed.

3.1. Power Flow Analysis

3.1.1. 2015 Heavy Summer Results

Results of the power flow analysis indicated that prior to the completion of the requested generation interconnection the Archer 230/115 kV #1 transformer was loaded above its nameplate rating, as high as 126%, for a number of outage combinations involving the Archer 230/115 #2 transformer.

The addition of the proposed project reduced the Archer transformer loading to below nameplate values for all outage combinations. The results of this scenario indicate that the proposed project positively impacts the reliability of the Cheyenne area transmission system.

The results for the Wayne Child project sensitivity showed no significant impacts with the requested generation interconnection on-line.

3.1.2. 2015 Light Autumn Results

No adverse impacts to the CLFP and surrounding transmission system were identified in the 2015LA power flow analysis as a result of the CLPT-G2 project.

The sensitivity scenario also showed no significant impacts in the power flow results.

3.2. Transient Stability Analysis

3.2.1. 2015 Heavy Summer Results

No adverse impacts to the CLFP and surrounding transmission system were identified in the 2015HS transient stability analysis as a result of the interconnection of the CLPT-G2 project. The system response to all disturbances was adequately damped and exhibited no voltage or frequency violations.

3.2.2. 2015 Light Autumn Results

No adverse impacts to the CLFP and surrounding transmission system were identified in the 2015LA transient stability analysis as a result of the interconnection of the CLPT-G2 project. The system response to all disturbances was adequately damped and exhibited no voltage or frequency violations.

3.3. TOT3 and TOT4A Sensitivity Results

The heavy summer power flow case was re-dispatched, with the proposed project off-line, to stress TOT3 to approximately 1730 MW; over the current path rating of 1680 MW. With this level of TOT3 flows there was post-contingency loading of 103% on the Archer-Stegall 230 kV line following the loss of the Ault-Laramie River 345 kV line. With the proposed project placed on-line the TOT3 flow increased to 1781 MW and the Archer-Stegall 230 kV overload was mitigated. The TOT3 analysis with the Wayne Child project modeled in-service provided similar, but with less impact, results. This demonstrates that the proposed project does not negatively impact the TOT3 rating and may facilitate an increased rating. See Appendix A for snapshots of the power flow for TOT3 with and without CLPT-G2 and the Wayne Child project.

For the simultaneous TOT3 and TOT4A sensitivity analysis the light winter power flow case was re-dispatched to stress the TOT3 and TOT4A rated paths to approximately 1600 MW and 900 MW respectively. With the proposed project off-line there was a post-contingent overload on the Archer-Stegall 230 kV line of 104% following the loss of the Ault-Laramie River 345 kV line. With the proposed project on-line, the flow on both rated paths increased; TOT3 increasing by approximately 50 MW and TOT4A increasing by approximately 30 MW. Even with the increased flow on the paths, the post-contingent Archer-Stegall 230 kV line loading was reduced to 99% for the critical contingency.

Both the TOT3 analysis and TOT3/TOT4A sensitivity analysis demonstrated that the proposed project positively impacts system performance.

3.4. Short Circuit Results

The short circuit analysis was initially performed without the proposed interconnection project. This gave the base case fault duties of the interrupting devices. Then the proposed project was put in service and the short circuit study was repeated. The incremental fault duty difference between the two studies gave the impact of the new generator on the existing interrupting devices in the study area. The short circuit fault currents for simulated faults at all of the moderately impacted substations are shown in Table 2. There were no fault currents large enough to overcome the capabilities of any breaker in the area.

It should be noted that the values in Table 2 represent the largest bus phase current for the listed fault. Bus faults extending further from the proposed POI than the buses listed in Table 2 were not included in the final analysis due to little or no fault current contribution from the proposed generation project. Detailed fault analysis results are available upon request.

Table 2: Short Circuit Fault Current Summary

Bus Fault		Fault Current Pre-CLPT-G2 (A)					Fault Current Post-CLPT-G2 (A)					CLPT-G2 Contribution (A)			
		3 L-G	2 L-G	1 L-G	L-L		3 L-G	2 L-G	1 L-G	L-L		3 L-G	2 L-G	1 L-G	L-L
Archer 115		13624	14498	15133	11776		16385	16903	17299	14168		2761	2405	2166	2392
Archer 230		9556	9102	8591	8257		10585	10002	9125	9149		1029	900	534	892
Ault 230		23558	23740	23481	20342		24228	24307	23925	20925		670	567	444	583
Cheyenne 115		12386	12125	11964	10708		13942	13518	12895	12057		1556	1393	931	1349
Cheyenne 230		8930	8185	7324	7715		9613	9014	7621	8308		683	829	297	593
Corlett 115		8528	7832	6412	7376		9263	8461	6678	8014		735	629	266	638
EB Park 115		8455	7694	5712	7314		10828	9646	6338	9369		2373	1952	626	2055
Happy Jack 115		9839	9309	8520	8508		10905	10216	9032	9432		1066	907	512	924
Hilltop 115		11606	11192	10700	10035		12962	12335	11439	11211		1356	1143	739	1176
NCAR 115		9592	8954	7845	8295		10657	9864	8300	9219		1065	910	455	924
Skyline 115		7321	6609	4835	6334		8487	7578	5146	7344		1166	969	311	1010
South Cheyenne 115		8246	7890	7140	7134		8727	8285	7376	7551		481	395	236	417
South Cheyenne 230		10468	9591	8341	9045		11336	10498	8696	9797		868	907	355	752
Swan Ranch 115		8116	7422	5920	7021		8711	7916	6124	7537		595	494	204	516
Warren 115		8830	8151	6808	7637		9827	9006	7184	8502		997	855	376	865

3.5. Results Summary

Based upon the results of the SIS as described in this Section 3, the CLFP transmission system can reliably accommodate the full 120 MW injection from the CLPT-G2 project.

4. Cost and Construction Schedule Estimates

The cost and time estimates represent good faith estimates necessary to interconnect to the system and are tabulated below. All estimates are in 2011 dollars.

Table 3: Cost Estimates

Direct Assigned Costs	
Substation Interconnection	$0.5 million
Network Upgrade Costs	
Substation (4 position ring)	$4.0 million
Transmission Line (2 mile double circuit)	$2.5 million

The expected in-service date for the Network Upgrades is no later than June 1, 2014.

5. Conclusions

Based on the assumptions specified in this report, the interconnection SIS identified no necessary upgrades, beyond those to connect to the system, to the CLFP transmission system to accommodate the full 120 MW request.