Generating Facility Interconnections
Electric Rule No. 21

Detailed Interconnection Study

Blue Mountain Electric Company

Blue Mountain Electric Company Project

13 Blizzard Mine Road

Wilseyville, California 95257

3,000 kW Synchronous Generators

Queue #1148-RD

Pacific Gas and Electric Company
05 May 2015

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1. Executive Summary

1.1 Generation Interconnection Requested

Blue Mountain Electric Company, an Interconnection Customer (IC), has requested a Generating Facility (GF) interconnection for Blue Mountain Electric Company (Project) to the Pacific Gas and Electric Company (PG&E)'s distribution system for a 3,000 kW Synchronous generating facility to be located at 13 Blizzard Mine Road, Wilseyville, California 95257. The Generating Facility will be connected to PG&E's West Point 1102 (163201102) 12kV distribution circuit. Interconnection will be in accordance with California Public Utility Commission's (CPUC) Generating Facility Interconnections, Electric Rule 21. The customer-requested operating date for the Project is 1 June 2016. This Project has been assigned the Queue # 1148-RD.

1.2 Project History

In accordance with the Electric Generating Facility Interconnections, Electric Rule 21, the IC passed the Electrical Independence Test (EIT) and agreed to proceed into the Detailed Interconnection Study (DIS). The DIS was conducted to determine the impacts of the Project on the PG&E distribution system and the results are documented in this report.

1.3 Scope of Detailed Interconnection Study

The Detailed Interconnection Study scope includes:

- Evaluation of the impacts the generators will have on PG&E's distribution system.
- The required work to maintain PG&E's operating conditions and adequate system protection.
- Any operating restrictions to be imposed on the generation facility in order to meet PG&E's system protection.
- Facilities require for system reinforcements with a non-binding good faith estimate of cost responsibility, and a non-binding good faith estimated time to construct.

1.4 Detailed Interconnection Study Results

1.4.1 System Stability

Steady state power flow analyses concluded that the Project, as proposed, will not overload West Point Bank 3 for any loading scenario. The generated powers will back feed into the transmission system. The existing line equipment at West Point 1102 circuit has the capability to handle the powers generated by interconnection facilities.

1.4.2 Voltage Fluctuation

Voltage fluctuation analyses concluded that the generation operating at unity power factor would not cause voltage flicker at the Point of Common Coupling (PCC) outside of Rule 2 limits.

1.4.3 Substation Voltage Regulation

Proper voltage regulation by the West Point Bank 3 may be affected due to the generation interconnection. Bank 3 LTC controller will need to be replaced with Beckwith controller.

1.4.4 Transmission Facilities

See Section 5 for Transmission requirement.

1.4.5 Protection Requirements

Protection requirements for the Project are presented in Section 4 and Section 6 of the report.

1.4.6 Non-binding Construction Schedule

The non-binding estimated construction schedule to engineer and construct the facilities is approximately **18-24 months** from the signing of the Generator Interconnection Agreement (GIA).

1.4.7 Non-binding Cost Estimate

The non-binding cost estimate of the Interconnection Facilities[1] to interconnect the project would be approximately **$2,045,000** excluding ITCC and Cost of Ownership.

[1] The distribution facilities necessary to physically and electrically interconnect the Project to PG&E's distribution system at the point of interconnection

1.5 Study Updates

The SIS was performed according to the assumptions shown in the Section 2. In the event that these assumptions are changed, an update study may be required to re-evaluate the Project's impact on the system. The IC would be responsible for paying for any such updating study. Examples of changes that might prompt such a study are:

- Withdrawal of a higher queued project from the queue.
- Change in interconnection date
- Change in Interconnection Queue position
- Change in Project's MW size
- Change in interconnection plan

1.6 Next Step

The next step in the Interconnection Process is the Facility Study or Interconnection Agreement. Once you have reviewed the results of this System Impact Study, please contact your Electric Generation Interconnection (EGI) Interconnection Manager to discuss arranging a results meeting and next steps meeting. During this meeting, PG&E will request additional information that will be necessary to move to the appropriate next step.

1.7 Reference Documents

The following are links to documents that are referenced within this document:

PG&E's Generation Interconnection Handbook:
http://www.pge.com/b2b/newgenerator/distributedgeneration/interconnectionhandbook/

PG&E's Transmission Interconnection Handbook:
http://www.pge.com/includes/docs/pdfs/shared/rates/tariffbook/ferc/tih/app_t.pdf

PG&E's Electric Rule 21:
http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf

PG&E's Metering Requirements:
http://www.pge.com/includes/docs/pdfs/shared/rates/tariffbook/ferc/tih/g1final.pdf

CPUC General Order 131-D:
http://docs.cpuc.ca.gov/published//Graphics/589.PDF

2. Project Information

2.1 Generating Facility Information

Blue Mountain Electric Company and PG&E agreed to proceed with system impact study for the proposed 3,000 kW synchronous generators to be interconnected with PG&E's distribution grid. The generating facility will be located on 13 Blizzard Mine Road, Wilseyville, California 95257. The IC proposes the installation of three Stamford LV 804R generators for a total generating capacity of 3,000 kW. The generators will operate as a wholesale power producer with 100% of the output to be exported to the PG&E distribution system.

The generating facility, as proposed, would be connected to PG&E's West Point Substation. West Point Substation has 2 distribution transformers that tap off of 60kV Transmission Line. The proposed 3,000 kW project would be interconnected through West Point 1102 circuit onto an existing PG&E 12 kV distribution bus at West Point Bank 3. The bank is protected by 60kV fuses. The Project Point of Interconnection (POI)Common Coupling (PCC) is located approcimately 350 feet south of fuse cutout (FCO) 57799 on West Point 1102 circuit.

2.2 Pending Interconnection Reques

None

2.3 Base Cases

Bank studies were performed with the following assumptions to determine the effects of the generating facility on the distribution system. Bank studies were performed for normal conditions, assuming the base cases listed below.

Table 2.3: Base Case Data

Case 1 (Peak) [2]	Capability (kW)	Peak Load (kW)	Existing Generation (kW)
Bank 2	10,395	4,619	202
West Point 1102	7,560	4,619	202

Case 2 (Minimum)	Capability (kW)	Minimum Load (kW)	Existing Generation (kW)
Bank 2	10,395	1,668	202
West Point 1102	7,560	1,668	202

[2] Peak and Off-Peak load calculation or load estimating for solar generation systems with no battery storage use daytime load from10 am to 4 pm while all other generation uses absolute maximum or minimum load.

2.4 Interconnection Assumptions

TABLE 2.4: Project Information and Equipment Characteristics

Project Name	Blue Mountain Electric Company
Customer-Proposed Commercial Operation Date	1 June 2016
Type of Generator(s) & Model	Synchronous: 3 – 1,163 kW Stamford LV 804R
Generators Data	Generator Nameplate: kW=3,489; kVA=4,362 Generator kVA base: 1454 Synchronous reactance (Xd) = 1.915 Transient reactance (X'd) = 0.152 Sub-transient reactance (X"d) = 0.113 Negative sequence reactance (X_2) = 0.152 Zero sequence reactance (X_0) = 0.024 • Neutral Grounding Resistor = 25 ohms
Total Output	4,362 kVA (3,000kW @ 0.8 power factor)
Power Factor	> 0.8 to 0.99 PF
Interconnection Configuration (Description)	Parallel operation with full export to West Point 1102 (163201102) circuit.
Transformer Data (Dedicated)	1 – 3,500 kVA @ Z = 7.0% 12,000 / 480 V Ygnd – Delta

2.5 Distribution System

TABLE 2.5: PG&E Distribution Circuit Characteristics

Substation / Feeder	West Point Bank 2 60 kV / 12 kV West Point 1102 (163201102)
Primary Voltage at POI	12 kV
Primary Line Configuration at POI	3-phase, 3-wire distribution circuit
Upstream Protective Devices	• West Point 1102/2 (IAC) • LR 4790 (WE 4C) • FCO 57799 (10FT)
Existing Significant Generation on Bank	• West Point 1102 - 202kW
Additional Proposed Generation on Bank	• None

2.6 Maps and Diagrams

The next page contains the following figures:

1. Vicinity map of the project providing an aerial image of the project site.
2. Single Line Diagram (SLD) of the circuit path from the POI to the Substation.

FIGURE 2.6A: Project Vicinity Sketch

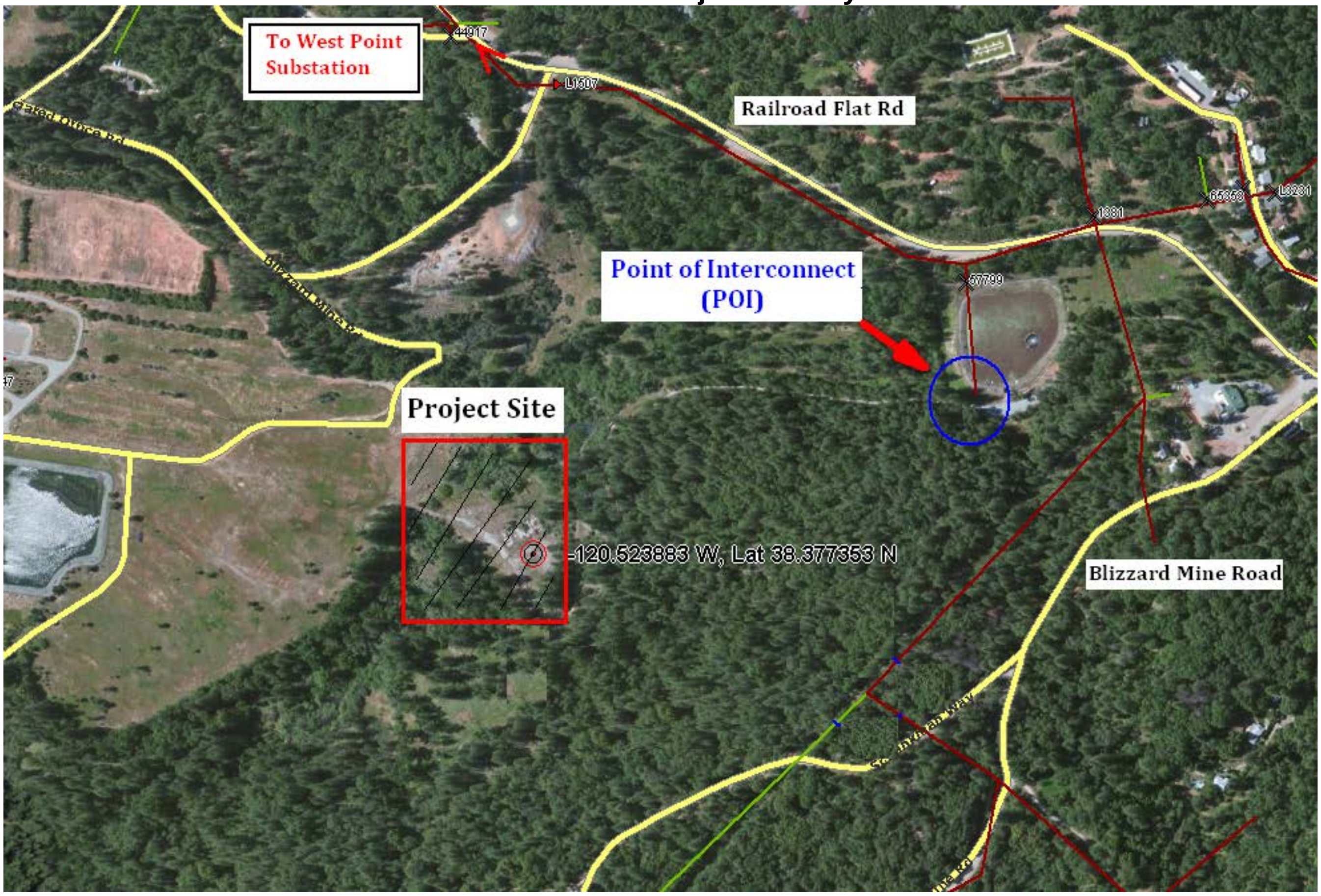
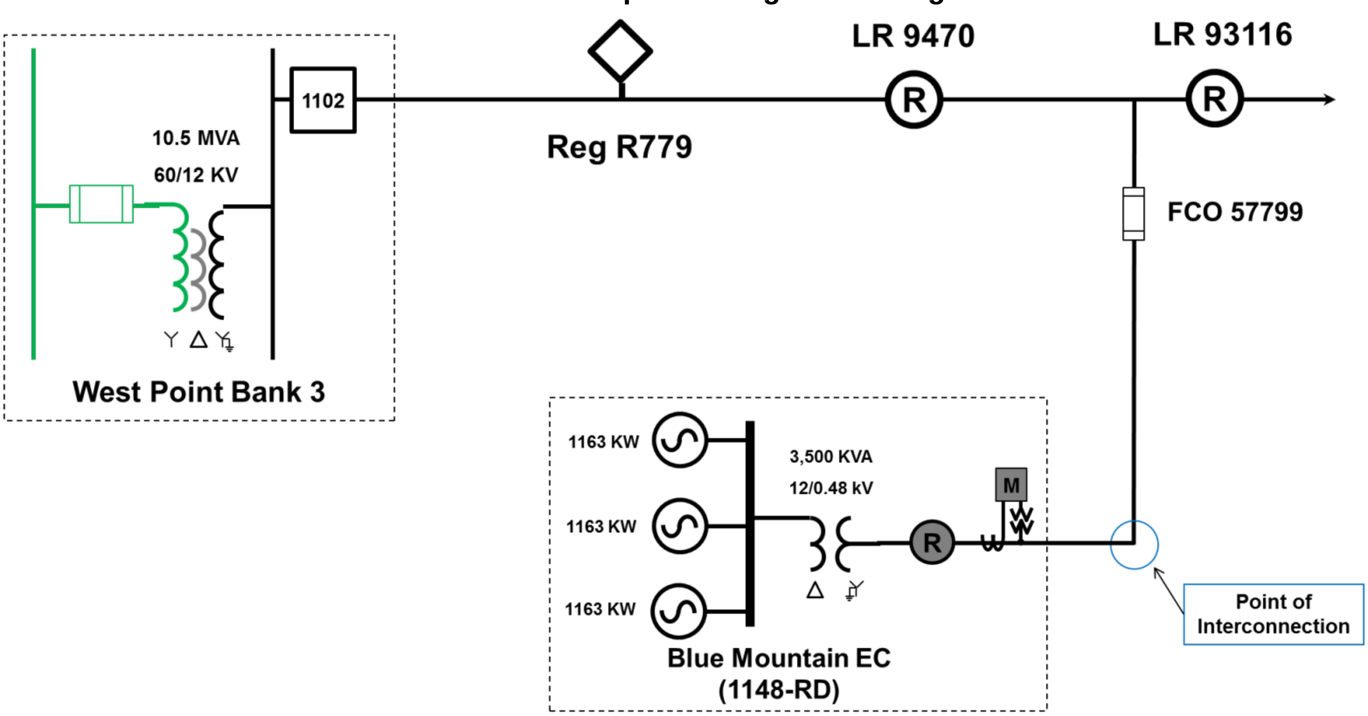


FIGURE 2.6B: Simplified Single Line Diagram



3. Distribution System Impacts Study

3.1 General Criteria for Identifying Overloads

The summer normal rated capacity for PG&E distribution substation transformers and voltage regulators is the highest applicable manufacturer's nameplate rating. The winter normal rated capacity is 1.2 times the nameplate rating. Substation regulator ratings are based on kVA transformed at maximum tap changer position.

The summer normal rated capacity for PG&E overhead distribution conductors in interior parts of the state is based on an ambient temperature of 43°C with a wind speed of two feet per second and a maximum conductor operating temperature of 75°C for aluminum and copper conductors or 80˚C for ACSR. The winter normal rated capacity is based on an ambient temperature of 16˚C with a wind speed of two feet per second.

The rated normal capacity for switches and circuit breakers on the PG&E distribution system during both summer and winter conditions is the highest applicable manufacturer's nameplate rating.

All single phase equipment on the PG&E distribution system is derated by 5% to account for the effects of phase imbalance. All air insulated equipment including overhead conductors is considered to be single phase for application of this rating. Three phase oil insulated equipment in a common tank and underground cables sharing a single conduit are not derated.

3.2 Substation Bank Loading

West Point Bank 2 is connected to a 12 kV distribution feeder; West Point 1102. The addition of the generation at the proposed size was evaluated against calculated minimum loading condition. The (N-1) contingency scenario is looked at to evaluate the effects of the largest feeder being tripped which reduces the total load on the substation. The following impacts were identified:

Table 3.A Bank Penetration

Bank / Feeders	Minimum Load (kW)	Aggregate DG (kW)	Final Bank Load (kW)
Bank #3	1,668	3,202	-1,534
CB 1103	1,668	202	
1148-RD	0	3,000	

Rated Power of Bank (kW)	TRF Rating (%)
10,395	15%

Bank analysis indicated that during the minimum loading scenario, the interconnection of 3,000kW of generations to the West Point 1102 will result in a reverse power flow through the West Point Bank 3. The normal capabilities of West Point Bank 3 are sufficient for this power flow, and therefore the bank would not be overloaded.

Due to the fact that power will back feed through West Point Bank 3, a SCADA communications will be required to accurately monitor power flow throughout the yeare. Since Bank 3 is a single feeder bank, this requirement is meet since the feeder has existing SCADA metering that is capable of monitoring the bi-directional Watt, VAR and Amp. However, additional upgrade is required.

Mitigations Required.

- Replace existing Bank 3 LTC controller with Beckwith Controller

3.3 Feeder Loading Study

Circuit studies were performed to determine if there are any equipment overloads due to the proposed generating facilities. Loading was examined with the generator on line for normal operating conditions. Normal operating conditions assumed the exiting generators are online. Circuit studies were performed for West Point 1102 under peak and minimum loading conditions. It was assumed that the generator would be operating at unity power factor. The feeder studies results were recorded in Table 3.B.

TABLE 3.B: Feeder Loading Study

Device Loading (kW)	Case 1	Case 2
Project OFF Line	**(kW)**	**(kW)**
CB 1102/2	4543	1554
Reg R779	3814	1316
LR 9470	2924	1002
PCC	0	0
Project ON Line		
CB 1102/2	1428	-1411
Reg R779	777	-1647
LR 9470	-74	-1953
PCC	-2963	-2962

Based on feeder loading studies resulted, the interconnection of 3,000kW of generation onto the West Point 1102 circuit would cause a reverse power flow toward West Point 1102 circuit breaker during minimum loading conditions. There is existing SCADA metering on West Point 1102 circuit breaker that is capable of monitoring the bi-directional Watt, VAR and Amp.

The operating capabilities of fuse cutout (FCO) 57799 and 2 ACSR conductor will be exceeded for the anticipated generation export under any operating conditions. The following works are required.

Mitigations Required

- Replace FCO 57799 with SCADA Nova Recloser
- Replace about 400 feet of 2 ACSR with 4/0 AL conductor

3.4 Voltage Regulation

West Point 1102 circuit has one source of line voltage regulation between the substation and the proposed Blue Mountain Electric Company generation site. Bank 3 at West Point Substation has a Station Load Tap Changer (LTC) that regulates the feeder voltages. The addition of the Blue Mountain Electric Company Project will offset some load measured by the Bank 3 Regulator, causing output voltage to be lower than without the generation online.

Analyses were performed to determine if there are any steady state voltage problems where the primary voltage is out of tolerance from Rule 2 Standards due to the proposed generating facilities. Steady state voltage was examined with the generator on line for the different system operating conditions.

Circuit studies were performed for the West Point 1102 feeder under peak and minimum loading conditions. It was assumed that the generator would be operating at unity power factor with the total export power of 3,000 kW. The voltage studies results were recorded on Table 3.C.

Table 3.C - Steady State Voltage Before Mitigation

Voltage on 120V Base	Case 1			Case 2		
	MAX	MIN	PCC	MAX	MIN	PCC
Project Off-Line						
1102 (V)	126.5	118.8	123.1	125.4	120.7	122.8
Project On-Line						
1102 (V)	124.9	**117.8**	122.8	123.5	119.4	121.3

Table 3.D – Steady State Voltage After Mitigation

Voltage on 120V Base	Case 1			Case 2		
	MAX	MIN	PCC	MAX	MIN	PCC
Project Off-Line						
1102 (V)	126.5	119.6	123.1	125.4	121.0	122.7
Project On-Line						
1102 (V)	124.9	118.8	122.8	124.0	120.4	122.5

Analysis has shown that the desensitization of the West Point Bank 3 LTC and its line regulators by the interconnection of the 3,000kW of generation will cause voltage conditions outside of Rule 2 limits. Mitigation will be required.

Mitigations Required

- Relocate Regulator R286 to about 2500 feet southwest of existing location

3.5 Instantaneous Voltage Fluctuation

In general, voltage flicker with regards to large scale distributed generation installations is defined as the change in the voltage at the Point of Common Coupling (PCC) due to a sudden change in current acting across impedance:

$\Delta V = \Delta I \cdot Z$

Where, **$Z = R \cdot \cos(\Theta) + X \cdot \sin(\Theta)$ = (Positive Sequence Thevenin System Impedance at the PCC)**
Θ = (Angle of Power Produced by the Generator)

The power factor ($\cos(\Theta)$) produced by the generator can typically be within a range of 0.90 lagging to 0.90 leading. Note that generations are limited to their nameplate KVA ratings, so operating at a power factor off of unity (1.0) would result in a reduction of real power being produced. Therefore, it is assumed that the generator facility would strive to maintain their output power factor as close to unity as possible.

PG&E and the California Public Utilities Commission (CPUC) require that voltage flicker on the distribution system be restricted to three volts or less on a 120 volt base. This limit may be increased to five volts if the circuit/substation is very rural or industrial in nature. The West Point substation serves a mix of residential, commercial, and industrial loads. Therefore, three volts flicker limitation will be applied to the interconnection of Blue Mountain Electric Company, a 8,654 kW generating facility.

There is no voltage regulation between West Point Substation and the Blue Mountain Electric Company project site.

Circuit studies were performed to determine if the voltage flicker caused by the proposed generating facility exceed three volts, on a 120-volt base.

The voltage flicker due to the Blue Mountain Electric Company interconnections was calculated by comparing the steady state voltage with generation on-line and the voltage of the circuit immediately after the generator trips off-line but before the voltage regulation equipment can react. Voltage flicker results were recorded on below Table.

Table 3.E - Calculated Fluctuation

Power Factor		MVA				
		3.00	2.25	2.00	1.50	0.75
Lagging	0.90	8.10	6.08	5.40	4.05	2.03
Lagging	0.93	7.42	5.57	4.95	3.71	1.86
Lagging	0.95	6.86	5.14	4.57	3.43	1.71
Lagging	0.99	5.03	3.77	3.36	2.52	1.26
Unity	1.00	3.45	2.59	2.30	1.72	0.86
Leading	-0.99	1.80	1.35	1.20	0.90	0.45
Leading	-0.95	0.31	0.23	0.20	0.15	0.08
Leading	-0.93	1.01	0.76	0.67	0.50	0.25
Leading	-0.90	1.90	1.42	1.26	0.95	0.47

Table 3.F - Simulated Fluctuation Before Mitigations

Voltage @ 120V Base	Case 1	Case 2
On Line	122.8	121.3
Off Line	120.0	118.7
ΔV	2.8	2.6

Analysis of this section has determined that there will be no significant impacts to the system when the project goes online.

No mitigation will be needed for Section 3.5.

4. Distribution Protection Study and Requirements

The major protection items are identified and detailed below. These would be required to be installed by PG&E as Special Facilities for the Interconnection Customer's proposed generation.

Per Section G2.1 of the PG&E Transmission Interconnection Handbook, PG&E protection requirements are designed and intended to protect the PG&E power system only. As a general rule, neither party should depend on the other for the protection of its own equipment.

Refer to PG&E's Generation Interconnection handbook for full requirements.

DIH: http://www.pge.com/b2b/newgenerator/distributedgeneration/interconnectionhandbook/
TIH: http://www.pge.com/mybusiness/customerservice/nonpgeutility/electrictransmission/tariffs/handbook/

4.1 Protection Settings and Overstressed Equipment

Short circuit studies were performed to determine the effect of the Project on short-circuits fault duties and impact on the existing distribution system. The fault duties were calculated before and after the Generating Facility Interconnection.

Table 4.A - Simulated Fluctuation After Mitigations

Fault Contribution (Primary Amps)	Project OFF Line			Project ON Line		
	L-G	L-L	L-L-L	L-G	L-L	L-L-L
Bus Fault (End of Line)						
PG&E	4063	2972	3432	4149	2972	3432
1148-RD	0	0	0	465	529	611
Total Fault Duty	4063	2972	3432	**4613**	**3500**	**4042**
LR4788 Fault						
PG&E	417	611	705	336	467	539
1148-RD	0	0	0	120	303	351
Total Fault Duty	417	611	705	**454**	**767**	**885**
PCC Fault						
PG&E	774	1118	1291	675	1118	1291
1148-RD	0	0	0	185	742	856
Total Fault Duty	774	1118	1291	**917**	**1847**	**2133**

Analysis of this section has determined that there will be no significant impacts to the system when the project goes online.

No mitigation will be needed for Section 4.1.

4.2 Unintentional Islanding Requirements

It is required that the generator trip off line within 2 seconds of the formation of an Unintended Island between the proposed generator and the automatic sectionalizing devices. The Project will be located beyond West Point 1102 LR 4790. The following analyses will determine whether anti-islanding requirements are met.

Table 4.B - Anti-Islanding

Device	Min. Load at Device (kW)	Exisitng Generation (kW)	Queued Generation (kW)	Project Generation (kW)	Aggregate Generation (kW)	Generation to Load Ratio (%)
Bank 3	1668	202	0	3000	3202	192.0%
CB 1102/2	1668	202	0	3000	3202	192.0%
LR 4790	1103	149	0	3000	3149	285.5%

The above table indicates that the project size is above 50% of the minimum load at all line sections. Since the proposed generation is not a certified anti-islanding generation, additional protection will be required for West Point 1106 circuit breaker and LR 4790 to prevent the installation of Direct Transfer Trip (DTT).

As for the possible islanding on Bank 3, Transmission Protection will provide mitigations or recommendation if any under Section 6. The following upgrades are required per Distribution analysis:

Mitigations Required:

- Install PT and enable reclose blocking for West Point 1102 OCB
- Replace LR4790 with SCADA NOVA Recloser with reclose blocking enable
- Install SCADA NOVA Recloser at the PCC (can use the same recloser as identify on Section 3.3)
- Install ground fault (59G) detection scheme at the PCC
- Install redundant sets of Utility grade relay at each generator
- Enable synchronizing relay (25) to supervise the synchronization with the PG&E Distribution System
- Enable devices 27, 59 and 81O/U

4.3 Generator's Fault Detection Requirements

It is required that the generator relaying see end-of-line on PG&E system and trip off line within 2 seconds for Distribution System faults (both line-to-line and line-to-ground). The protection requirements can be realized with a 51V, voltage restraint overcurrent relay, for line-to-line and 59G, ground overvoltage relay; for line-to-ground fault protection.

4.3.1 Phase Faults Detection Scheme

In order to detect any phase-to-phase faults on the PG&E distribution system, a voltage restraint overcurrent (51V) scheme or a voltage control (51C) scheme must be used. If these schemes do not work, then the project will require direct transfer trip to ensure the generator trips offline for end of line fault conditions. The following fault analysis will determine whether Device 51V or 51C schemes can be used for this Micro Grid System.

Generator's fault detection analysis was performed under the following condition:

- It is assumed that only one generation is online
- It is assumed that no load is present at the generating facility
- It is assumed that the generator CT ratio is 1600/5
- Generators information is based on the data provided in Section 2
- Generator's Xd reactance is used
- The Device 51V or 51C will be located at the generator's terminal

Table 4.C - Voltage Restraint/ Control Scheme Validation

51V 3Φ Fault Test (Amps @ GF Voltage)	PGE ON / DG ON			PGE OFF / DG ON		
	Sub	EOL	PCC	Sub	EOL	PCC
Voltage (Vp) @ Gen [pu]	0.03	0.56	0.02	0.03	0.04	0.02
DG Contribution [A]	885	480	899	885	887	899
60% of DG Contribution [A]	531	288	539	531	532	539
51V Trip Value [A]	525	1175	525	525	525	525
Min. 51C Trip Value [A]	160	160	160	160	160	160

CT Ratio =	320	
Minimum Tap of Relay =	0.5	Amps
Minimum 51V limit of Relay =	0.25	p.u.
DG Operating Voltage =	0.48	kV
Nameplate Power of DG =	1454	kVA
DG Nameplate Current =	1749	Amps
Pickup (1.2x Nameplate) =	2099	Amps

Fault studies indicated that either 51V or 51C protection scheme can be used for phase-to-phase faults for the Blue Mountain generation. The following settings are available to the customer to prevent the need to install Direct Transfer Trip (DTT).

Option 1: Device 51C Settings:

- Minimum Pickup = 300 amps at 480V
- Voltage settings = 0.8 pu
- Time Delay = 1.5 seconds

Option 2: Device 51V Settings:

- Minimum Pickup = 2000 amps at 480V
- Time Dial = 0.15
- Curve = IEC-I
- Enable voltage restraint
- Install SCADA Nova Reclose West of LR 36676

Mitigations Required:

- Install phase fault detection scheme at the PCC
- Install SCADA Nova Reclose west of LR 36676

4.3.2 Ground Fault Detection Scheme

For the ground fault detection requirement, PG&E's 12 kV distribution system is a three-wire distribution circuit and does not have a current carrying neutral. Therefore, the generating facility should be connected to the distribution system using an effectively ungrounded connection system that does not contribute zero sequence current to the PG&E distribution system. The primary of the interconnection transformer for this generating station is wye-ungrounded winding as per the submitted information which meets the said requirement. Since the SCCR is greater than 10% and as required by Section 4.2, ground fault detection scheme is required.

In order to detect any ground fault on the 12 kV circuit, a ground overvoltage relays (ANSI Device 59G) is required to detect ground faults on the utility side of the Point of Common Coupling (PCC). Per provided SLD, the customer proposed to install grounding transformer on the wye-grounded portion of the primary step-up transformer with (59G) voltage relays and a 13 ohms parallel resistor with proper wattage across the secondary. Fuses are permitted on the primary side of the potential transformers but not in the transformer secondary. The following table will determined whether ground fault detection scheme can detect end-of-line fault.

Table 4.D – Ground Detection Validation

LG Fault	PGE ON / DG ON			PGE OFF / DG ON		
	Sub	EOL	PCC	Sub	EOL	PCC
V0 at POI (Vpu)	0.22	0.33	0.63	1.00	1.00	1.00

Fault studies indicate that a ground overvoltage relay can see the end of line with the following settings:

Minimum Voltage Pick-up = 36 volts
Time Delay = 1.5 seconds

Mitigations Required:

- Install voltage detection scheme at the PCC

PG&E's protection requirements are designed and intended to protect the PG&E power system only. Refer to "*PG&E's Generation Interconnection Handbook"* for the full requirements.

5. Transmission System Study Impacts

The CAISO controlled-grid Reliability Criteria, which incorporates the Western Electricity Coordinating Council (WECC) and NERC planning criteria, was used to evaluate the impact of the Project on the PG&E transmission system.

5.1 Contingencies

Power Flow analysis was performed. These base case were used to simulate the impact of the Project during normal (CAISO Category "A") operating conditions as well as during single (CAISO Category "B") and selected multiple (CAISO Category "C") contingency conditions.

The types of contingencies evaluated under each category are summarized in Table 5-1.

Table 5-5: Summary of Planning Standards

Contingencies	Description
CAISO Category "A"	All facilities in service – Normal Conditions
CAISO Category "B"	• B1 - All single generator outages. • B2 - All single transmission circuit outages. • B3 - All single transformer outages. • Selected overlapping single generator and transmission circuit outages for the transmission lines and generators within the study area.
CAISO Category "C"	• C1 - SLG Fault, with Normal Clearing: Bus outages (60-230 kV) • C2 - SLG Fault, with Normal Clearing: Breaker failures (excluding bus tie and sectionalizing breakers) at the same bus section above. • C3 - Combination of any two-generator/transmission line/transformer outages. • C4 - Bipolar (dc) Line • C5 - Outages of double circuit tower lines (60-230 kV) • C6 - SLG Fault, with Delayed Clearing: Generator • C7 - SLG Fault, with Delayed Clearing: Transmission Line • C8 - SLG Fault, with Delayed Clearing: Transformer • C9 - SLG Fault, with Delayed Clearing: Bus Section

Although most of the CAISO Category "C" contingencies have been considered to be evaluated as part of this study, it is impractical to study all the CAISO Category "C" contingencies. For this reason, select critical Category "C" contingencies (C1 – C9) were evaluated as part of this study.

5.2 Study Results

5.2.1 Normal Overloads (CAISO Category "A")

Under projected 2019 summer off peak conditions, the addition of the Project did not cause any new Category "A" normal overload. Under projected 2019 summer peak conditions, the addition of the Project did not cause any new normal overloads.

5.2.2 Emergency Overloads (CAISO Category "B")

Under projected 2019 summer off peak conditions, the addition of the Project did not cause any new CAISO Category "B" emergency overload. Under projected 2019 summer peak conditions, the addition of the Project did not cause any new emergency overloads.

5.2.3 Emergency Overloads (CAISO Category "C")

Under projected 2019 summer off peak conditions, the addition of the Project did not cause any new CAISO Category "C" emergency overloads. Under projected 2019 summer peak conditions, the addition of the Project did not cause any new emergency overloads.

5.3 Overload Mitigation

The power flow study to evaluate the impact of the Project on the PG&E transmission system found no new overloads caused by the Project. Therefore, no overload mitigation is required.

6. Transmission Protection Study and Requirements

Dinuba Substation Loading	Peak Load (kW)	Min Load (kW)	Existing Generation (kW)
Bank 2	3,541	1,775	100
Bank 3	4,619	1,668	202
Blue Mountain (1148-RD)			3,000

Transformer Protection:

The maximum fault current contribution from the three generator units is about 130A at 60kV. This is above the existing 100A fuse on Westpoint Bank #3. For a bank fault and high side ground fault, the 59G is not able to detect faults and trip the generator breakers. In addition, for an open phase condition on the 60kV side (i.e. blown fuse), there is not enough negative sequence voltage (V2) for the existing 47 device to detect unbalance and trip the feeder breaker. The following upgrades are required:

Mitigations Required:

- Install a three phase interrupting device such as circuit breaker or a circuit switcher with its associated bank protection relays on Westpoint Bank#3.
- Install the latest integrated standard for PG&E bank protection. The bank protection tripping will be hard wired to trip the feeder breaker to avoid DTT from the bank protection to the cogenerator breaker(s).

60 kV Transmission System Protection:

Based on the system transmission protection study, it was determined that a direct transfer trip is required from Valley Springs CB 6322/6312 to trip the cogenerator breaker(s). The 59G relay required for distribution ground fault detection cannot see ground faults on the 60kV line. For an end of line phase faults on the Valley Springs – Westpoint 60kV line, each generator unit 51V or 51C is not adequate to provide phase fault protection. As such DTT is required for fault protection on the 60kV line. The following are the communication medium that are approved by PG&E for direct transfer trip application:

- Direct Fiber to PG&E Substation with proper interface provisioning
- Licensed Microwave with proper interface provisioning
- Class A DS0 4-Wire Lease Line provisions by Local Exchange Carrier (LEC) (Risk - see Section F.0.. Notification)
- Direct Transfer Trip (DTT) Telecommunication Options via the new Class B, T1 Lease Options (see Section F5.0 appendix of the PG&E interconnection handbook)

West Point can also be fed through Valley Springs – Calaveras Cement 60kV line by closing SW 95 and opening SW 6315. If customer chooses to stay online when West Point is fed through Valley Spring – Calaveras Cement 60kV line, DTT must also be initiated from Valley Springs CB 6412/6422.

Mitigations Required:

- Install one (1) RFL GARD 8000 (CD-58507) initiated from Valley Springs CB 6322/6312 line relays, CB 6412/6422, bus differential relay and breaker open for transmitting DTT to the remote cogeneration breaker(s) with alarm indication to Tesla Switching center.
- Install one (1) RFL GARD 8000 (CD-58506 for Cogen terminal) for receiving DTT from Valley Springs substation.

7. Substation Study and Impacts

7.1 Assumptions and Clarifications

1. This proposed substation scope is based on PG&E preliminary Protection Requirements and Distribution planning input.
2. Detailed scope will be developed when the project moves to implementation phase.
3. This estimate is based on PG&E standard design and construction practices.
4. The estimated costs here do not include any applicable ITCC tax.
5. Costs do not assume extensive permitting effort.
6. Cost does not include any remedial work for impact on neighboring properties.
7. This estimate does not include right-of-way acquisition or land acquisition costs.
8. Costs do not include extensive environmental mitigation costs.
9. Leased lines are considered acceptable communication channels for telemetry and Direct Transfer Trip (DTT). However, if procurement of leased lines is not possible a different type of communication channel, acceptable to PG&E, will need to be used. Other type of communication channels based on fiber optics and/or microwave will likely result in increased overall telecommunication costs associated with the interconnection project. Customer is responsible for procurement and operation of all the communication channels. Cost for procurement of leased lines or other communication channels is not included in our cost estimate.
10. IC will be solely responsible for obtaining leased lines or other communication channels between PG&E facilities or between PG&E Facilities and IC's Generation site for Telemetry, EMS/SCADA and DTT.
11. The Point of Interconnection (POI) is tap on West Point PH 1102 Circuit.

7.2 Network Upgrade Requirements

West Point PH
60 kV Circuit Breaker For Bank#3

- Install new Dead End Structure before Bank#3.
- Install 60 kV Switches on the Dead end Structure.
- Install Circuit Breaker under the Dead end Structure to protect Bank#3.
- Reconfiguration of the 60 kV feed might be required to feed Bank#3 via Circuit Breaker.
- Run conduits and wires from Bank#3 Circuit Breaker to Bank#3 Protection package.

Valley Springs Sub

DTT Transmit from CBs 6312, 6322, 6412, 6422 and Bus Differential Relays to Gen Site Breaker

- Cost only includes the installation of equipment at Valley Springs. The exact communication channel cost is not included and is based on the medium available and is sole responsibility of the Generator.
- Install DTT Transmitter RFL Gard 8000 on Rack#8. Tranmsitter equipment is based on leased lines and could change if Telecomm finds it more feasible to go with other medium such as Microwave. The circuit can be explored in detail only at project execution phase.
- Connect Local Remote and SCADA Cut-in Cut-out Switches on Rack#8
- Connect Alarms and Status points to HMI.
- Provide 2 DC Circuits to Rack#8 from DC Panel 1. CBs 8, 10, 12, 14 and 16 are shown as spares.
- Install separate MVAJ Relays on following Racks to pick up Trip Signals from the Breakers listes.
    - Rack 22 For CB 6312
    - Rack 24 for CB 6322
    - Rack 27 for CB 6412
    - Rack 29 for CB 6422

- Wire Breaker Statuses to MVAJ Relays for each of the above 4 Breakers.
- Wire the MVAJ Relays to the RFL Gard 8000 on Rack#8.
- 2 MVAJ Relays per Breaker might be required if Set A and Set B signals are to be kept separate.
- Alarms will be communicated to Tesla Switching Station. Communication channel will be required at additional cost if it does not exist between Valley Springs and Tesla Switching Station.
- Bus Differential Relays are on Rack 10 and 11 for Bus 1 and 2 respectivey.
- Instal MVAJ Relays on Bus Differential Racks 10 and 11 and wire the MVAJ Relays to RFL Gard 8000.
- Install Trip Cut out Switches for each trip signal going to RFL Gard 8000.

7.3 Distribution Upgrades

West Point PH
Protection package For Bank#3

- Remove existing Rack for Bank#3 and its equipment. Existing Rack is a swing Rack.
- Install new 19" Rack in place of the existing Rack.
- Install new Bank Protection package on the new Rack to protect Bank#3.
- Hardwire Bank#3 Relays to trip Feeder 1102.
- Run conduits and wires from Bank#3 Rack to Feeder 1102 IPAC Cabinet.
- Wire the relays to SCADA and Annunciator.

Reclose Blocking for Feeder 1102 For Bank#3

- Install Riser pole under the Outgoing 12 kV Feed of Feeder 1102.
- Run new conduits and Ground to the new Riser pole.
- Install Fuse Cut out, PT, PT Secondary Box on the Riser pole.
- Drop a tap from the Overhead outgoing lines into an Insulator and then to the Fuse Cut-out.
- Wire the PT Secondary from the Secondary Box on the pole to the 1102 IPAC Cabinet via Pull Boxes.
- Enable Reclose Block on Feeder 1102 Relays.
- Drawings indicate an existing IPAC Cabinet for 1102, if it found at execution stagre that this is not the case then an IPAC Cabinet will be required.

LTC Controller for Bank#3

- Replace exsiting LTC Controller for Bank#3 with a bi-directional Beckwith Controller.

7.4 Interconnection Facilities

Gen Site

- The IC is required to comply with all the applicable requirements in the PG&E Interconnection Handbook, plus specific requirements established for this project.
- PG&E will review IC's protection and revenue metering design and will install PG&E revenue meter inside a customer-provided metering enclosure.
- PG&E will provide pre-parallel inspection and witness testing at the IC's facility.
- PG&E will Install RFL Gard 8000 Receiver to receive DTT Signal from Valley Springs and wire the output to a terminal block.
- PG&E will install required Control and Cutout Switches for DTT.
- Customer will wire the signal received from the terminal block onwards to trip its Breakers.
- Customer will provide one 19" Rack for PG&E to install the DTT equipment.
- PG&E will install an RTU to transmit alarms to Valley Springs and PG&E Operation Centers.
- Additional communication channel besides DTT Channel will be required and it is Generation Customer's responsibility to arrange the communication circuits.
- PG&E installation at Customer site do not include installation of raceways or cable trays and is Customer's responsibility.

8. Interconnections Facilities

DG Customer On-Site Required Work: A portion of the work detailed here may need to be completed by PG&E.
Primary service has not been established. The scope of the work required on-site will include the following:

1. **Three-phase Protective Device**
   Install a new 12kV circuit breaker, line recloser or interrupter as close to the Point of Interconnection as possible for each dedicated gen-tie feeder (typically within one span of overhead line or 200 feet of unspliced underground cable), with phase and ground overcurrent protection to protect PG&E from faults on the customer side OR a main circuit breaker. The protective device must be approved by PG&E and coordinate with PG&E's source side protection.

   Note: Microprocessor-based relays that are applied as a multifunctional protection device will require backup relays (redundancy). A second set of multifunction relay will satisfy this requirement. Relays must be utility grade and from the PG&E approved list (See Table G2-4, p. G2-27, 28 in the TIH).

   IC to provide all necessary conduits, pull ropes, pads, and barriers to meet PG&E requirements at the switchgear location.

2. **Gang-Operated Disconnect Switch**
   A disconnect switch can be located on either the PG&E's side or customer's side of interconnection point. The switch must be gang operated and have a visible open point (air gap, visible either through a viewing window or an operable door). PG&E operating personnel must be able to independently operate the switch and lock it in the open position. This switch will be the PG&E operable disconnect point for the Generating Facility.

3. **DC Shunt Trip**
   The new breaker(s) must use a DC shunt trip scheme; the battery system must be designed to trip the breaker after eight hours loss of AC power to the battery charger. Battery Requirements are in Appendix T of PG&E's Transmission Interconnection Handbook (available on line at <http://www.pge.com/includes/docs/pdfs/shared/rates/tariffbook/ferc/tih/app_t.pdf>.
   The switchgear must include either a DC under-voltage alarm to the 24/7 manned control location for the Project or a DC under-voltage relay that trips the breaker. Please note that PG&E does not permit fuses in the DC trip circuit (including the relay power supplies).

4. **Current Transformer Requirements**
   The relaying current transformers (C.T.'s) must be located on the utility side of the breaker. The C.T.'s must be utility grade and must be rated for protection applications. Avoid C.T. ratios greater than 600:5. PG&E uses lower ground relay settings than industry standard and for typical relay setting ranges (0.5 amp minimum available secondary pickup), C.T. ratios larger than 600:5 may not provide sufficient sensitivity to permit coordination with PG&E's equipment.

5. Closing Supervision

TThe switchgear must incorporate closing supervision schemes to prevent the main breakers from closing if the Generating Facility is on line and is out of synchronism with the PG&E system. The following schemes are acceptable:

> **Generator Unit Interlocks:** the close circuit for the breaker is supervised by status inputs from each generator so that it cannot close unless all the generators are off line.

6. Frequency and Voltage Protection

A certified inverter will meet the frequency and voltage protection requirement. Otherwise, switchgear for Generating Facility interconnections must include over-frequency and under-frequency relays (ANSI device number 81O/U) and overvoltage and under-voltage relays (device numbers 59 and 27). These relays must be approved by PG&E as specified above and must be redundant; the relay functions can be provided by multi-function relays installed to provide over-current protection. The standard settings for distribution interconnections are as follows:

> **Under-voltage (27)**: the generating facility must initiate trip in not longer than 10 cycles for voltages below 50% of nominal voltage and not longer than 120 cycles (2 seconds) for voltages below 88% of nominal voltage.
>
> **Overvoltage (59)**: the generating facility must initiate trip in not longer than 10 cycles for voltages above 120% of nominal voltage and not longer than 60 cycles (1 second) for voltages above 110% of nominal voltage.
>
> **Over-frequency/Under-frequency (81O/U)**: the generating facility must initiate trip in not longer than 10 cycles for frequencies below 59.3 Hz and must initiate trip in not longer than 10 cycles for frequencies above 60.5 Hz.

7. Redundant Relays and Ground Over-current Relays

Generator protective relays are used for detecting faults out on the PG&E system. The protection package must include non-directional unrestrained phase and ground overcurrent relays (ANSI device 51 and 51N). To meet PG&E's redundancy requirements, the switchgear must include either four single phase relays (traditional configuration with one relay on each phase and a ground relay on the common return) or two multi-phase / multi-function relays. If the selected relays have two phase elements and a ground element, the phase which is not protected by the first relay must be one of the protected phases on the second relay.

The minimum pickup settings for these relays must not exceed 80% of the corresponding settings on PG&E's source side protective device. To meet PG&E's coordination requirements, the trip time of the Generating Facility relays must be at least 0.3 seconds faster than the corresponding PG&E source side relay for all levels of fault current up to the appropriate symmetrical fault duty and must be less than 75% of the PG&E relay trip time throughout this current range.

A list of PG&E approved relays is provided on pages 27 and 28 of Section G2 of PG&E's Transmission Interconnection Handbook (available on line at <http://www.pge.com/includes/docs/pdfs/shared/rates/tariffbook/ferc/tih/g2final.pdf>.

8. Phase Fault Detection Scheme

The customer will be responsible for installing an adequate protection scheme to detect phase fault conditions on PG&E's distribution system. The phase fault detection scheme should be wired to trip the customer's primary service breaker during phases fault conditions on the utility system. See Section 4.3.1 for requirement settings.

9. Ground Fault Sensing Scheme

The customer will be responsible for installing an adequate protection scheme to sense ground fault conditions on PG&E's distribution system. The ground fault detection scheme should be wired to trip the customer's primary service breaker during ground fault conditions on the utility system. See Section 4.3.2 for requirement settings.

9. Revenue Metering and Telemetry

PG&E requires revenue metering at the PCC.

Per *"PG&E Electric Rule 21"*, J.5:

If the nameplate rating of the Generating Facility is 1 MW or greater, telemetering equipment at the Net Generator Output Metering location may be required at the Producer's expense.

- A PG&E RTU is required for SCADA/EMS telemetry for PG&E's visibility. Since the generation capacity of the Project is 1MW or greater, the SCADA communication scheme at the Generation site will meet the telemetry requirement. See Section 4.2.
- The IC is to provide the leased line, space, raceway, interface wires, and AC and DC power as required.
- The IC is responsible for the installation of the necessary conduits and substructures in order for PG&E to provide the new 12 kV primary metered service to this site. One six-inch conduit plus one spare will be required to accommodate the new 600 Al MCM underground cable. Detailed instructions on the process will be provided.

The net generating facility output will be at least 1MW. **A PG&E SCADA communication scheme will be required to monitor the export of the generating facility at the point of interconnection.**

10. CA ISO Registration

This section pertains to those projects of which this is applicable.

Wholesale Generators: Wholesale generators that participate in the CAISO market must execute CAISO's Participating Generating Agreement and meter their power deliveries in accordance with CAISO Tariff. Metering installations must comply with the Meter Certification Requirements and Standards set forth in the CAISO Tariff and Protocols. Meters for Participating Generators are required at the point of interconnection.

Please refer to the link below to the Interconnection Handbook for more info regarding CAISO Metering

http://www.pge.com/includes/docs/pdfs/shared/rates/tariffbook/ferc/tih/g1final.pdf

Or visit the CAISO website for more information and application.

http://www.caiso.com/market/Pages/MeteringTelemetry/Default.aspx

11. Pre-parallel Inspection Requirements

Please note upon notification of the generator(s) readiness for the pre-parallel inspection, it can take up to 30 days for the pre-parallel inspection due to available resources. The following items must be completed prior to the scheduling of the inspection:

- All required agreements executed.
- There must be an accessible, visible and lockable disconnect switch. (This must be shown on the single line drawing. Include manufacturer name and model number.)
- Breakers should be shunt trip from a battery in accordance with the attached criteria. (This requirement must be shown in the three line drawings. Include manufacturer name, size and model number.)
- A copy of the final signed building permit from the local authority having jurisdiction over the installation of the co-generation system is provided.
- If required, all electric work by PG&E completed.
- If required, gas service/meter (PG&E owned) installation completed.

Once the inspection is scheduled, our Station Test Department requires the following information be provided a minimum of 15 days prior to the inspection:

- Single line and three line relay drawings approved. (An electronic version is preferred.)
- The G5-1 Form completed and returned electronically. (Will be provided)
- Basic Info Requirement Form completed and returned electronically. (Will be provided)
- Field "bench test" of relays approved. (An electronic version is preferred.)
- Battery Discharge Test Report and Commissioning Test Checklist. (Form will be provided)

12. Environmental Evaluation / Permitting

12.1 CPUC General Order 131-D

PG&E is subject to the jurisdiction of the California Public Utilities Commission (CPUC) and must comply with CPUC General Order 131-D (Order) on the construction, modification, alteration, or addition of all electric transmission facilities (i.e., lines, substations, switchyards, etc.). This includes facilities to be constructed by others and deeded to PG&E. In most cases where PG&E’s electric facilities are under 200 kV and are part of a larger project (i.e., electric generation plant), the Order exempts PG&E from obtaining an approval from the CPUC provided its planned facilities have been included in the larger project’s California Environmental Quality Act(CEQA) review, the review has included circulation with the State Clearinghouse, and the project’s lead agency (i.e., California Energy Commission) finds no significant unavoidable environmental impacts. PG&E or the project developer may proceed with construction once PG&E has filed notice with the CPUC and the public on the project’s exempt status, and the public has had a chance to protest PG&E’s claim of exemption. If PG&E facilities are not included in the larger project’s CEQA review, or if the project does not qualify for the exemption, PG&E may need to seek approval from the CPUC (i.e., Permit to Construct) taking as much as 18 months or more since the CPUC would need to conduct its own environmental evaluation (i.e., Negative Declaration or Environmental Impact Report).

When PG&E’s transmission lines are designed for immediate or eventual operation at 200 kV or more, the Order requires PG&E to obtain a Certificate of Convenience and Public Necessity (CPCN) from the CPUC unless one of the following exemptions applies: the replacement of existing power line facilities or supporting structures with equivalent facilities or structures, the minor relocation of existing facilities, the conversion of existing overhead lines (greater than 200 kV) to underground, or the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built. Obtaining a CPCN can take as much as 18 months or more if the CPUC needs to conduct its own CEQA review, while a CPCN with the environmental review already done takes only 4-6 months or less.

Regardless of the voltage of PG&E's interconnection facilities, PG&E recommends that the project proponent include those facilities in its project description and application to the lead agency performing CEQA review on the project. The lead agency must consider the environmental impacts of the interconnection electric facility, whether built by the developer with the intent to transfer ownership to PG&E or to be built and owned by PG&E directly. If the lead agency makes a finding of no significant unavoidable environmental impacts from construction of substation or under-200 kV power line facilities, PG&E may be able to file an Advice Letter with the CPUC and publish public notice of the proposed construction of the facilities. The noticing process takes about 90 days if no protests are filed, but should be done as early as possible so that a protest does not delay construction. PG&E has no control over the time it takes the CPUC to respond when issues arise. If the protest is granted, PG&E may then need to apply for a formal permit to construct the project (i.e., Permit to Construct). Facilities built under this procedure must also be designed to include consideration of electric and magnetic field (EMF) mitigation measures pursuant to PG&E "EMF Design Guidelines for New Electrical Facilities: Transmission, Substation and Distribution". For projects that are not eligible for the Advice Letter/notice process but have already undergone CEQA review, PG&E would likely be able to file a "short-form" CPCN or PTC application, which takes about 4-6 months to process.

Please see Section III, in General Order 131-D. This document can be found in the CPUC's web page at: http://www.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/589.htm

12.2 CPUC Section 851

Because PG&E is subject to the jurisdiction of the CPUC, it must also comply with Public Utilities Code Section 851. Among other things, this code provision requires PG&E to obtain CPUC approval of leases and licenses to use PG&E property, including rights-of-way granted to third parties for Interconnection Facilities. Obtaining CPUC approval for a Section 851 application can take several months, and requires compliance with the California Environmental Quality Act (CEQA). PG&E recommends that Section 851 issues be identified as early as possible so that the necessary application can be prepared and processed. As with GO 131-D compliance, PG&E recommends that the project proponent include any facilities that may be affected by Section 851 in the lead agency CEQA review so that the CPUC does not need to undertake additional CEQA review in connection with its Section 851 approval.

13. Cost Estimates Summary

The detailed estimation of costs below includes interconnection and/or system upgrades required to interconnect the Project to PG&E's distribution system, but does not include any in-plant facilities constructed, owned and operated by the Applicant. The below costs are only estimates using average cost without actual field verification.

Network Upgrades	IC Costs	PG&E Costs
Transmission Facilities		
Valley Springs Substation		
Install DTT Transmitter RFL Gard 8000 for DTT scheme from Valley Springs CB 6322/6312 and 6412/6422 to the remote cogeneration breaker(s)	$285,000	
Install and test MVAJ Relays on Rack for CB 6312 and 6322 and wire MVAJ to RFL Gard 8000	$50,000	
Install and test MVAJ Relays on Rack for CB 6412 and 6422 and wire MVAJ to RFL Gard 8000	$50,000	
Install MVAJ Relay on Rack#10 and Wire Bus Differential Relays for Bus 1 to MVAJ Relay, wire MVAJ Relay output to RFL Gard 8000.	$40,000	
Install MVAJ Relay on Rack#11 and Wire Bus Differential Relays for Bus 2 to MVAJ Relay, wire MVAJ Relay output to RFL Gard 8000.	$40,000	
West Point PH		
Install new Dead End Structure, Switches and Circuit Breaker for Bank#3. Install Grounding and conduits.	$450,000	
Tesla Switching Station		
Make updates to the system to receive signals from Valley Springs	$50,000	
Network Upgrades Subtotal	**$965,000**	**$0**

Distribution Upgrades	IC Costs	PG&E Costs
West Point Substation		
Install Riser pole and PT and enable reclose blocking scheme at 1102 OCB		$145,000
Install new Beckwith regulator controller for Bank 3 LTC	$60,000	
Install Bank Proteciton package for Bank#3	$500,000	
Install hardwire tripping from Bank 3 Relays to 1102/2 OCB	$80,000	
West Point 1102 Circuit		
Replace LR4790 with SCADA Nova Recloser to enable Reclose Blocking		$75,000
Install SCADA Nova Recloser west of LR36676	$75,000	
Relocate Regulator R286 about 2500 ft southwest of existing location	$90,000	
Replace FCO 57799 with SCADA Nova Recloser	$75,000	
Replace about 400ft of 2ACSR with 4/0 AL	$40,000	
Distribution Upgrades Subtotal	**$920,000**	**$220,000**

Interconnection Facilities Upgrades	IC Costs	PG&E Costs
Generating Facility		
First Pre-parallel inspection and testing witnessing		$10,000
Protection Review	$10,000	
Install one DTT RFL Gard 8000 Receivers	$70,000	
Install RTU	$50,000	
PG&E revenue metering	$15,000	
Primary Service – Overhead	$15,000	
Install about 1,500 ft reconductoring from POI to Gen Site (to be installed by IC)		
Install visible open switch at PCC (to be installed by IC)		
Install Ground Fault Detection (to be installed by IC)		
CAISO Metering provided by IC (cost not included here)		
Interconnection Facilities Upgrades Subtotal	**$160,000**	**$10,000**

Total Project Costs	IC Costs	PG&E Costs
Total Project Cost (excludes COO)	$2,045,000	$230,000
Total ITCC[2]	TBD	
Option 1: *Monthly Cost of Ownership (COO) (Total*0.46%)*	*$4,968.00*	
Option 2: *One-Time COO in lieu of Monthly COO (Total*0.46%*13.07*12)*	*$779,181.12*	

NOTES:

2 Not subject to ITCC on contribution. ITCC is exempt for wholesale generators that meet the IRS Safe Harbor Provisions. PG&E currently does not require the Interconnection Customer to provide security to cover the potential tax liability on the Interconnection Facilities, Distribution Upgrades, and Network Upgrades per the IRS Safe Harbor Provisions (IRS Notice 88-129). PG&E reserves the right to require, on a nondiscriminatory basis, the Interconnection Customer to provide such security, in a form reasonably acceptable to PG&E as indicated in Article 11 of the SGIA, an amount up to the cost consequences of any current tax liability. Upon request and within sixty (60) Calendar Days' notice, the Interconnection Customer shall provide PG&E such ITCC security or ITCC payment in the event that Safe Harbor Provisions have not been met, in the form requested by PG&E.

*If queue-ahead project withdraw, this project will have to absorb these costs.

14. Requirements Prior to Pre-parallel Inspection and Operation

14.1 PG&E System Work

The following is the required work on the PG&E System prior to the pre-parallel inspection:

1. Install DTT scheme from Valley Springs Sub to generating facilities
2. Replace West Point Bank 3 60kV fuses with 60 kV three-phase protection package
3. Install hardwire tripping from Bank 3 Relays to 1102/2 OCB
4. Replace existing Bank 3 LTC controller with Beckwith controller
5. Install PT and enable reclose blocking for West Point 1102 OCB
6. Replace LR 4790 with SCADA Recloser with RB feature
7. Install SCADA Recloser west of LR 36676
8. Relocate Regulator R286 2500 feet southwest of existing location
9. Replace FCO 57799 with SCADA Recloser
10. Reconductor about 400 ft of 2 ASCR with 4/0 AL
11. Install one DTT RFL Gard 8000 Receivers at Gen Site
12. Install RTU at Gen Site

14.2 Interconnection Facility Work

The following is the required work for the interconnection facilities prior to the pre-parallel inspection:

1. Primary Service must be established. Primary service requirements can be found in the PG&E Green Book or provided by the PG&E Service Planning Department.
2. Applicant is to provide an approved PG&E switch that is accessible, lockable, and gang-operated beyond the meter at the PCC
3. Install protection requirement as outline on Section 4.2 and 4.3.

14.3 Requirements Documentation

The following is the required work prior to the pre-parallel inspection:

1. Applicant to provide a complete set of layout drawings and elevations of the switchgear including dimensioned drawings of the PG&E revenue metering section showing the current transformer and potential transformer mountings
2. Applicant to provide manufacturers' specification sheets for the breaker, primary disconnect switch, batteries and charger, generator step-up transformer, current transformers and potential transformers
3. Applicant to provide relay settings for primary switchgear
4. Applicant to provide updated Single and 3-line wiring diagrams
5. Applicant to provide AC/DC schematic diagram
6. Applicant to provide a copy of Form G5-1 relay settings and the bench test report of the relays before PG&E will schedule a pre-parallel inspection of the generating facility (Primary Service requirement)
7. Applicant to provide battery sizing calculations and type as described in Transmission Interconnection Handbook

14.4 Parallel Operation Requirements

In order to release this project for parallel operation with the PG&E distribution system, the following tasks are required:

4. Approval of the customer's 3-line wiring diagrams, control and relay diagrams
5. Approval of relay settings
6. Approval of operation and control sequence descriptions (function description)
7. Approval of customer's required relay test reports and Form G5-1
8. Pre-parallel inspection
9. Execution of the operating agreement
10. All the required upgrades are completed

14.5 Operation Requirements

Blue Mountain Electric Company ability to operate the generating facilities at the 13 Blizzard Mine Road, Wilseyville, California 95257 is guaranteed only when the PG&E system is in the normal operating configuration and all required protection and regulation equipment is operational. PG&E reserves the right to require the Blue Mountain Electric Company generations to separate from the PG&E system if required for safety or system stability during an abnormal condition. In particular, the Blue Mountain Electric Company generator will not be allowed to operate in parallel with PG&E if the PG&E circuit source feeding the plant is switched to a source configuration different from that shown in drawings on Section 2.6.

Signage Required at AC Disconnect Location

PG&E LOCKABLE VISIBLE GENERATOR DISCONNECT SWITCH

Note: Sign will be permanent and will have a white background with 1½ inch red lettering.

This sign should be attached to the Disconnect itself; copies should be attached to any gates or doors which will be used by PG&E personnel to access the disconnect switch.

WARNING GENERATOR INSTALLED ON PREMISES

POSSIBLE DANGER OF ELECTRICAL BACKFEED

CHECK INSTALLATION BEFORE PERFORMING ANY WORK

DISCONNECT SWITCH IS LOCATED <*SPECIFIC LOCATION*>

Note: Sign will be permanent and will have a white background with ½ inch red lettering.

This sign should be located on or near the Main Utility Breaker; a copy should be attached to the Electrical Room door if the Main Utility Breaker is located indoors.

For interconnections using multiple generator disconnects, include the following text above the disconnect locations: "THIS SYSTEM HAS *[n]* GENERATOR DISCONNECTS. *[BOTH/ALL n]* DISCONNECTS MUST BE OPENED TO ISOLATE THE SYSTEM."

Where the disconnect location is distant from the Main Breaker or the route to the disconnect is complex, include a site plan showing the disconnect location on permanent material.

16. Appendix B – Battery Requirements for Interconnection

The purpose of this document is to ensure safety and reliability of Pacific Gas and Electric Company and its customers who will connect to our systems. The recommendations made here will ensure that the system operates as designed.

Because of serious reliability, safety and reduced life concerns with sealed (also called Valve Regulated Lead Acid – VRLA) batteries industry wide, PG & E has decided to completely stop the use of sealed batteries in our Substation or any switchgear installations or interconnection using these batteries. Flooded lead acid (calcium, antimony) and Nickel-Cadmium (NiCd) are the only batteries acceptable in these installations. Switchgear compartments typically see very high temperatures, and if sealed batteries are used they will dry out in less than a few years causing safety and reliability concerns along with not having the capability to trip breakers.

A side by side comparison of IEEE Std 450-2002 Section 4.2.3 (IEEE Recommended Practice for Maintenance, Testing and Replacement of Vented lead acid batteries for Stationary applications –also referred as Flooded batteries) and IEEE Std 1188-1996 Section 4.2.2 Subsections a, b & c. (IEEE Recommended Practice for Maintenance, Testing and Replacement of Valve-regulated batteries for Stationary application- also referred as VRLA) clearly demonstrates that VRLA requires Quarterly ohmic resistance testing compare to yearly ohmic testing for flooded batteries. Experience industry wide indicates problem with doing ohmic tests on VRLA because of the design of battery and trying to make connections to the terminals and interconnecting hardware. Even if ohmic resistance reading is not done on flooded battery, the failure modes can be detected by other means whereas with VRLA eliminating this test could cause dry out condition and ultimately catastrophic failure. In hot environment VRLA would require charger compensation as well as monitoring which is expensive and still not proven to be adequate. In the telecommunication industry there are presently trials under way for system wide replacements of VRLA with Flooded or NiCd batteries. PG & E recommends use of NiCd batteries in switchgear cubicle because of better performance under extreme temperatures. Flooded batteries can also be used in switchgear.

Additional reasoning for not using VRLA in substation as pointed out by IEEE Battery working group Chairman in the recent paper published in IEEE. “Summarizing the issue for VRLA batteries, there is a considerable risk involved in installing a single VRLA string in a substation. If parallel strings are installed, to operate reliably, they must be redundant, either by design or by a sufficient degree of conservatism in the sizing calculation. In building in redundancy, however, the
main aim of reducing battery costs is compromised. Despite the early claims of maintenance-free operation, VRLA batteries require considerable surveillance and testing to maintain a high degree of reliability, IEEE 1188-1996 [2] recommends quarterly internal ohmic measurements and annual discharge testing of VRLA. These measures are largely ignored by the telephone operating companies because of their low loads and use of parallel strings, as detailed above. In substation operation, however, these practices are doubly important because of the higher currents involved”.

It is recommended for the third party customer to provide the following documentation to PG &E Protection department for approval:

1. Type of Battery (Flooded lead acid or NiCd). Monoblock (multiples cells in a jar) batteries from C & D, EnerSys or other vendors will be acceptable. Battery rack must be designed to withstand loading based on zone 4.
2. Detail information of load including continuous and momentary. No minimum load requirement- Smallest flooded acid may be the limitation.
3. Battery sizing calculation based on IEEE 485-1983 (IEEE recommended Practice for Sizing Large Lead Storage Batteries for Generating Stations and Substations) and minimum hours discharge rate using manufacturer software (to ensure proper discharge curve is used) using aging factor of 1.25 and design margin of 1.1 to be clearly shown on the calculation. Charger sizing calculation based on battery size with recharge time of 12 hours assuming charger will support the continuous load as well as recharges the battery at the same time.
4. When battery is installed proof of three (3) hour discharge testing to ensure battery has the capacity to support the load and trip
5. Document showing what kind of maintenance will be done (Monthly, Quarterly, Yearly, etc.)
6. Monitoring of minimum battery low voltage by separate voltage relay or through charger and provide critical alarm to SCADA or monitoring system