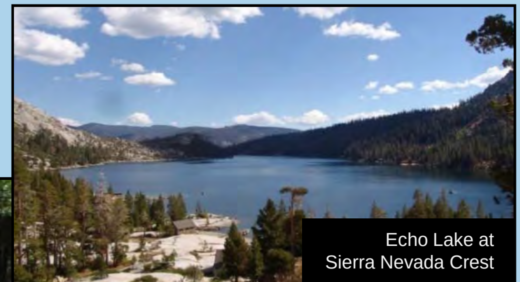
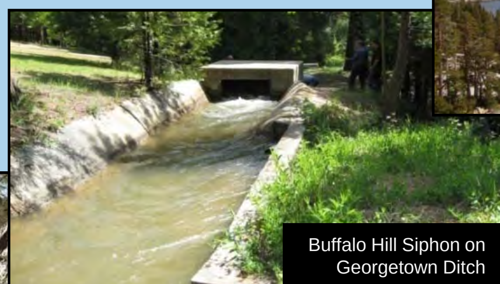
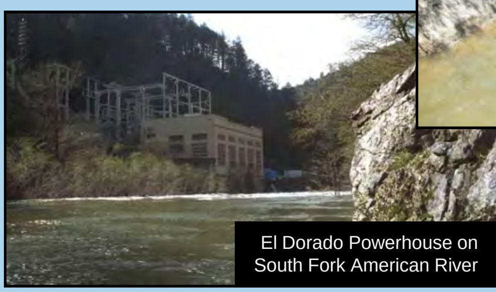
- Appendices -
Final El Dorado County Hydroelectric Development Options Study


Echo Lake at Sierra Nevada Crest


Buffalo Hill Siphon on Georgetown Ditch


El Dorado Powerhouse on South Fork American River

Prepared for

El Dorado County Water Agency
3932 Ponderosa Road, Suite 200
Shingle Springs, CA 95682

El Dorado Irrigation District
2890 Mosquito Road
Placerville, California 95667

Prepared by

EN2 RESOURCES, INC.
Water and Energy Consulting Services

July 24, 2009

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EN2 Resources, Inc.
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In Association With
California Water Consulting, Inc.
Carlton Engineering, Inc.
Domenichelli & Associates
Navigant Consulting, Inc.
Water Resources Engineering

July 24, 2009

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A2 Hydroelectric Development Options Report: Hydro Station Equipment and Technologies

A1.1 El Dorado Main 2 PRS 1

Photo 1 – El Dorado Main 2 Pressure Reducing Station No. 1 at Reservoir 3

PRIORITY:
Recommended for immediate implementation

PURVEYOR LEAD: EID

Project Category: Feed-In Tariff

Design Head (ft): 222

Design Flow (cfs): 24

Nameplate capacity (kW): 360

Estimated Annual MWh/year: 1,739

Capital Cost to Construct (Estimated): $1,556,000

Annual Income: $205,976 (assumes 20-year FIT agreement with PG&E; annual revenues cannot be reasonably projected beyond the 20-year analysis period)

EXISTING FEATURES:

Avg. annual flow (cfs)	Distance to 3-phase Power (ft)	Pipeline (in.)	Access Road	Downstream Storage	Land Ownership
21	**500**	**30**	**Y**	**Y**	**EID/USFS**

PROJECT DESCRIPTION:

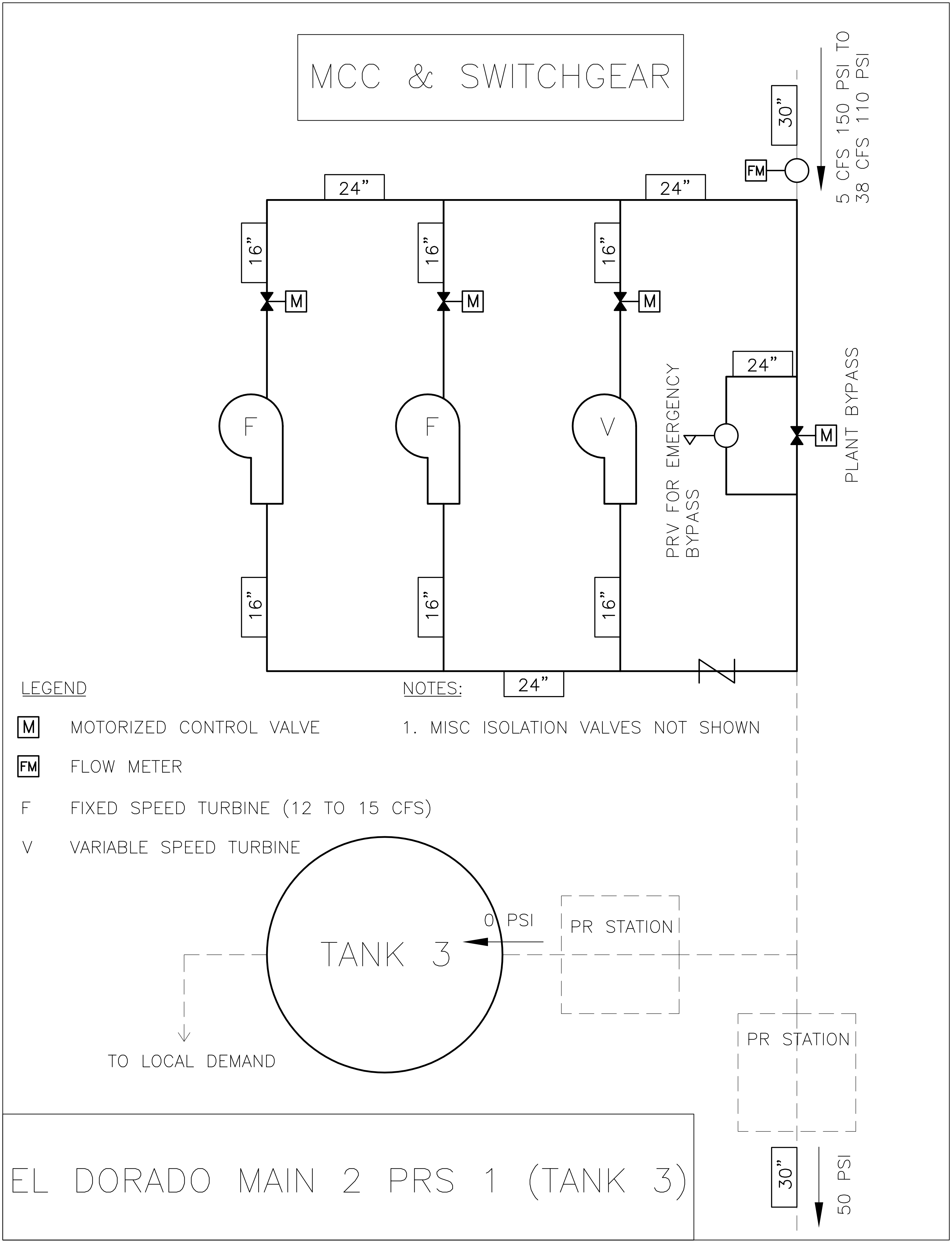
This project is at an existing PRS on El Dorado Main 2 at the inlet to Reservoir 3, located adjacent to the U.S. Forest Service (USFS), Institute of Forest Genetics property, on Carson Road. The energy production is somewhat higher when compared to the other PR sites (approx. 1,700 MWh). The PRS structure is located adjacent to the Reservoir 3 property. Area within the Reservoir 3 property is available with few structures other than the existing tank. Placement on the adjacent USFS property would be an option. 3-phase power is nearby. Placing the hydro site on the Reservoir 3 property would require additional piping from the existing 30-inch pipeline, adding cost to the project. The hydro station would consist of three PATs, with one turbine operating at variable speed with a regenerative power converter. The facilities would be housed in a masonry building approximately 400 square feet in area. The flows vary more than some sites but are higher and there is available storage at Reservoir 3 to assist in flow regulation. This is a FIT project.

El Dorado Main 2 PRS 1 (Tank 3)
Engineer's Preliminary Estimate of Probable Costs

Element Description	Estimated Quantity	Units	Unit Price (installed)		Estimated Amount	
Mobilization & Site work						
Mobilization, Bonds, Insurance	1	LS	$	30,000	$	30,000
Traffic Control	1	LS	$	1,500	$	1,500
Site Grading & Paving & Access	1	LS	$	25,000	$	25,000
Fencing	1	LS	$	10,000	$	10,000
				Subtotal =	**$**	**66,500**
Pipe, Valves and Fittings						
Intake and Return Tie into existing 30" line (Including de-water of pipe)	1	LS	$	30,000	$	30,000
24" In -Line Bypass Valve, piping & vault	1	LS	$	32,000	$	32,000
24" pipe to and from plant	60	LF	$	200	$	12,000
Intake and Return Manifolds	1	LS	$	20,000	$	20,000
16" turbine pipe runs	50	lf	$	185	$	9,250
12" motorized control valve	3	EA	$	9,500	$	28,500
12" pressure reducing valve	1	EA	$	8,500	$	8,500
24" check valve	1	EA	$	11,000	$	11,000
isolation valves, reducers, misc fittings	1	LS	$	22,000	$	22,000
24" flow meter	1	EA	$	16,000	$	16,000
				Subtotal =	**$**	**189,250**
Turbine/Generator Units						
120 KW Pump as Turbine/Generator Units Installed	3	EA	$	125,000	$	375,000
				Subtotal =	**$**	**375,000**
Electrical Equipment & Tie-in to Grid						
Electrical Controls/Switchgear for turbine/generator units	1	LS	$	120,000	$	120,000
Electrical utility /transformer , misc site electrical	1	LS	$	95,000	$	95,000
Hook-up to Grid (power lines, transformers, switches)	1	LS	$	45,000	$	45,000
				Subtotal =	**$**	**260,000**
Building and Misc Structural						
Masonry building	400	SF	$	150	$	60,000
Foundation structure (concrete)	8	CY	$	550	$	4,400
Roofing & Misc supports	1	LS	$	40,000	$	30,000
				Subtotal =	**$**	**94,400**
	Materials/Installation Subtotal =				**$**	**985,150**
	15% Construction Contingency Costs=				$	147,773
	TOTAL CONSTRUCTION COST:				**$**	**1,133,000**
Non -Construction Costs						
Admin/Planning/Design/Environmental Docs (% of construction costs)	15%	LS			$	169,950
Environmental Mitigation (% of construction costs)	8%	LS			$	90,640
Right of Way Costs	0.5	AC	$	30,000	$	15,000
Construction Administration (% of construction costs)	8%	LS			$	90,640
					$	56,650
				Subtotal =	**$**	**423,000**
	TOTAL ESTIMATED COST =				**$**	**1,556,000**

Annual Costs				
Administration and Insurance ($0.0033/kWh)	1700000	$0.0033	$	5,610
Operation & Maintenance (Labor)			$	7,058
Repair and Replacement (Parts and Material), (0.3% of total construction cost)		0.30%	$	3,399
Subtotal			$	16,067
Contingency (20%)		20%	$	3,213
Total O&M			$	19,280

EL DORADO MAIN 2 PRS 1 (TANK 3)



LEGEND

- M — MOTORIZED CONTROL VALVE
- FM — FLOW METER
- F — FIXED SPEED TURBINE (12 TO 15 CFS)
- V — VARIABLE SPEED TURBINE

NOTES:

1. MISC ISOLATION VALVES NOT SHOWN

A1.2 El Dorado Main 2 PRS 3

Photo 2 – El Dorado Main 2 Pressure Reducing Station No. 3 west of Reservoir 3

PRIORITY:
Recommended for reoperation study

PURVEYOR LEAD: EID

Project Category: Feed-In Tariff

Design Head (ft): 152

Design Flow (cfs): 24

Nameplate capacity (kW): 195

Estimated Annual MWh/year: 892

Capital Cost to Construct (Estimated): $1,409,000

Annual Income: $109,667 (assumes 20-year FIT agreement with PG&E; annual revenues cannot be reasonably projected beyond the 20-year analysis period)

EXISTING FEATURES:

Avg. annual flow (cfs)	Distance to 3-phase Power (ft)	Pipeline (in.)	Access Road	Downstream Storage	Land Ownership
14	**1,000**	**24**	**Y**	**Y**	**EID**

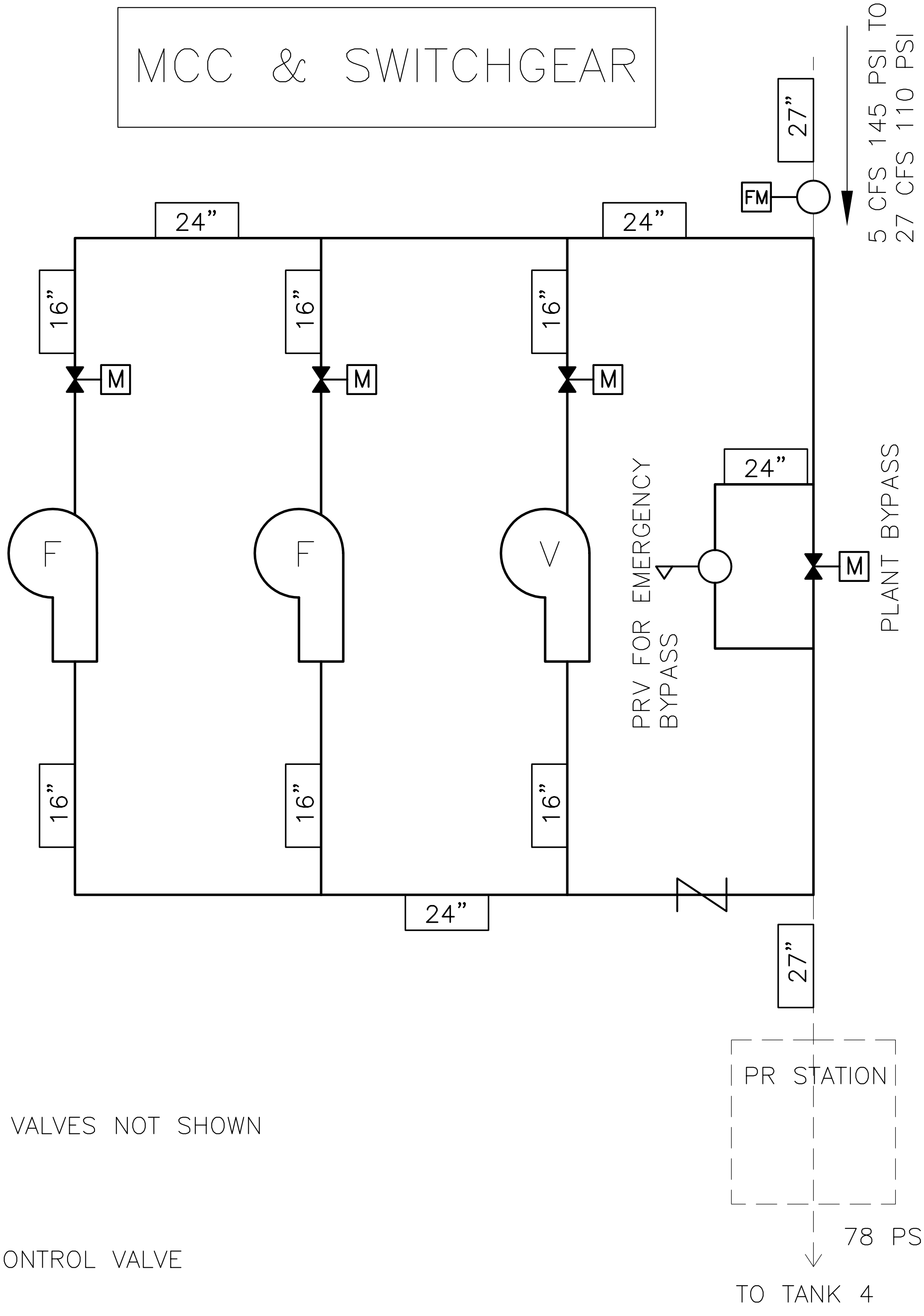
PROJECT DESCRIPTION:

This project is at an existing PRS on EID's El Dorado Main 2 system, located 4,500 feet downstream from Reservoir 3 on Whispering Wind Drive. The site, situated at 2,270 feet elevation, is relatively flat and has good construction access and 3-phase power nearby. The hydro station would consist of three PATs with one turbine operating at variable speed with a regenerative power converter. The proposed facilities will be housed in a masonry building approximately 400 square feet in area. As with many of the PRS sites there is no system storage and flows vary widely, requiring flow regulation through multiple units and valve controls. This is a FIT project with relatively low construction costs.

El Dorado Main 2 PRS 3
Engineer's Preliminary Estimate of Probable Costs

Element Description	Estimated Quantity	Units	Unit Price (installed)	Estimated Amount
Mobilization & Site work				
Mobilization, Bonds, Insurance	1	LS	$ 25,000	$ 25,000
Traffic Control	1	LS	$ 2,500	$ 2,500
Site Grading & Paving & Access	1	LS	$ 30,000	$ 30,000
Fencing	1	LS	$ 10,000	$ 10,000
			Subtotal =	**$ 67,500**
Pipe, Valves and Fittings				
Intake and Return Tie into existing 24" line (Including de-water of pipe)	1	LS	$ 25,000	$ 25,000
24" In -Line Bypass Valve, piping & vault	1	LS	$ 32,000	$ 32,000
24" pipe to and from plant	60	LF	$ 200	$ 12,000
Intake and Return Manifolds	1	LS	$ 20,000	$ 20,000
16" turbine pipe runs	50	lf	$ 185	$ 9,250
12" motorized control valve	3	EA	$ 9,500	$ 28,500
12" pressure reducing valve	1	EA	$ 8,500	$ 8,500
24" check valve	1	EA	$ 11,000	$ 11,000
isolation valves, reducers, misc fittings	1	LS	$ 22,000	$ 22,000
24" flow meter	1	EA	$ 16,000	$ 16,000
			Subtotal =	**$ 184,250**
Turbine/Generator Units				
65 KW Pump as Turbine/Generator Units Installed	3	EA	$ 90,000	$ 270,000
			Subtotal =	**$ 270,000**
Electrical Equipment & Tie-in to Grid				
Electrical Controls/Switchgear for turbine/generator units	1	LS	$ 110,000	$ 110,000
Electrical utility /transformer , misc site electrical	1	LS	$ 95,000	$ 95,000
Hook-up to Grid (power lines, transformers, switches)	1	LS	$ 60,000	$ 60,000
			Subtotal =	**$ 265,000**
Building and Misc Structural				
Masonry building	400	SF	$ 150	$ 60,000
Foundation structure (concrete)	8	CY	$ 550	$ 4,400
Roofing & Misc supports	1	LS	$ 40,000	$ 40,000
			Subtotal =	**$ 104,400**
	Materials/Installation Subtotal =			**$ 891,150**
	15% Construction Contingency Costs=			$ 133,673
	TOTAL CONSTRUCTION COST:			**$ 1,025,000**
Non -Construction Costs				
Admin/Planning/Design/Environmental Docs (% of construction costs)	15%	LS		$ 153,750
Environmental Mitigation (% of construction costs)	8%	LS		$ 82,000
Right of Way Costs	0.5	AC	$ 30,000	$ 15,000
Construction Administration (% of construction costs)	8%	LS		$ 82,000
Financing Cost				$ 51,250
			Subtotal =	**$ 384,000**
	TOTAL ESTIMATED COST =			**$ 1,409,000**

Annual Costs			
Administration and Insurance ($0.0033/kWh)	890000	$0.0033	$ 2,937
Operation & Maintenance (Labor)			$ 7,058
Repair and Replacement (Parts and Material), (0.3% of total construction cost)		0.30%	$ 3,075
Subtotal			$ 13,070
Contingency (20%)		20%	$ 2,614
Total O&M			$ 15,684



NOTES:

1. MISC ISOLATION VALVES NOT SHOWN

LEGEND

M	MOTORIZED CONTROL VALVE
FM	FLOW METER
F	FIXED SPEED TURBINE (7 TO 12 CFS)
V	VARIABLE SPEED TURBINE

EL DORADO MAIN 2 PRS 3

A1.3 Oak Ridge Tanks to Bass Lake Tanks Pumped Storage

Photo 3 – One of Bass Lake Tanks

PRIORITY:
Recommended for reoperation study

PURVEYOR LEAD: EID

Project Category: Feed-In Tariff

Design Head (ft): 400

Design Flow (cfs): 10

Nameplate capacity (kW): 280

Estimated Gross/Net Annual MWh/year: 874/(30)

Capital Cost to Construct (Estimated): $774,000

Gross Annual Income: $117,388 (assumes 20-year FIT agreement with PG&E; annual revenues cannot be reasonably projected beyond the 20-year analysis period)

EXISTING FEATURES:

Avg. annual flow (cfs)	Distance to 3-phase Power (ft)	Pipeline (in.)	Access Road	Downstream Storage	Land Ownership
5	**300**	**18**	**Y**	**Y**	**EID**

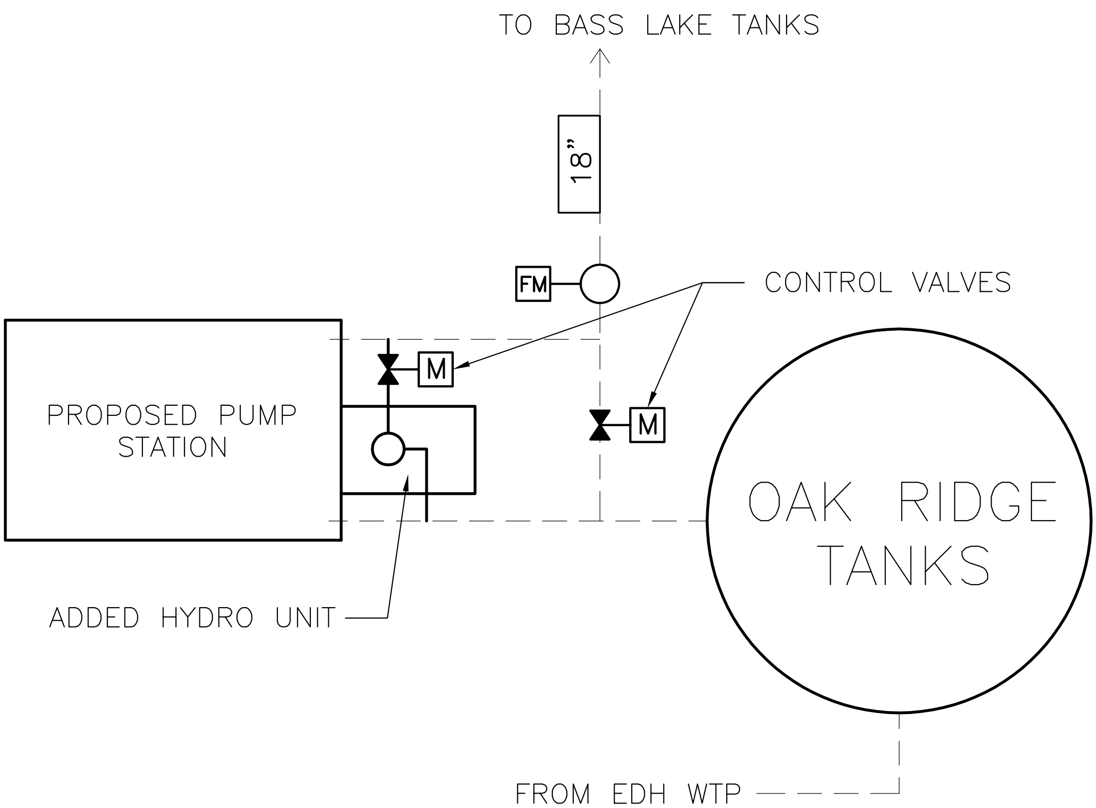
PROJECT DESCRIPTION:

This project is at a pumping station currently under design at the Oak Ridge storage facilities in the community of El Dorado Hills. The project would be a pumped storage project, pumping flow from the Oak Ridge storage tanks to Bass Lake storage tanks during off-peak hours, then generating power at the Oak Ridge tanks site during peak energy demand periods. The hydro station will consist of one PAT with variable speed and a regenerative power converter. The facilities will be housed in a masonry building approximately 400 square feet in area. Access and distance to power grid are good. This is a FIT project with relatively low overall construction costs. Whether or not the existing storage is sufficient for feasible operations will be an important component to the future review of this hydro option.

Oak Ridge Tanks to Bass Lake Tanks Pump
Engineer's Preliminary Estimate of Probable Costs

Element Description	Estimated Quantity	Units	Unit Price (installed)	Estimated Amount
Mobilization & Site work				
Mobilization, Bonds, Insurance	0	LS	$ 20,000	$ -
Traffic Control	0	LS	$ 1,000	$ -
Site Grading & Paving & Access	1	LS	$ 5,000	$ 5,000
Fencing	0	LS	$ 10,000	$ -
			Subtotal =	**$ 5,000**
Pipe, Valves and Fittings				
Turbine Intake and Return Tie into new pump station & tank lines	1	LS	$ 25,000	$ 25,000
12" In -Line Bypass Valve, piping & vault	1	LS	$ 18,000	$ 18,000
12" pipe to and turbine	40	LF	$ 150	$ 6,000
10" turbine pipe runs	25	lf	$ 135	$ 3,375
10" motorized control valve	1	EA	$ 8,500	$ 8,500
12" check valve	1	EA	$ 7,500	$ 7,500
isolation valves, reducers, misc fittings	1	LS	$ 16,000	$ 16,000
			Subtotal =	**$ 84,375**
Turbine/Generator Units & pump sta modifications				
280 KW Pump as Turbine/Generator Units Installed	1	EA	$ 180,000	$ 180,000
Additional Pumping Capacity at new PS	1	EA	$ 50,000	$ 50,000
Valve Modifications at Bass Lake Tanks	1	EA	$ 15,000	$ 15,000
			Subtotal =	**$ 245,000**
Electrical Equipment & Tie-in to Grid				
Electrical Controls/Switchgear for turbine/generator units	1	LS	$ 70,000	$ 70,000
Electrical utility /transformer , misc site electrical	1	LS	$ 35,000	$ 35,000
Hook-up to Grid (power lines, transformers, switches)	1	LS	$ 18,000	$ 18,000
			Subtotal =	**$ 123,000**
Building and Misc Structural				
Masonry building	150	SF	$ 150	$ 22,500
Foundation structure (concrete)	4	CY	$ 550	$ 2,200
Roofing & Misc supports	1	LS	$ 10,000	$ 10,000
			Subtotal =	**$ 34,700**
	Materials/Installation Subtotal =			**$ 492,075**
	15% Construction Contingency Costs=			$ 73,811
	TOTAL CONSTRUCTION COST:			**$ 566,000**
Non -Construction Costs				
Admin/Planning/Design/Environmental Docs (% of construction costs)	18%	LS		$ 101,880
Environmental Mitigation (% of construction costs)	0%	LS		$ -
Right of Way Costs	0	AC	$ 30,000	$ -
Construction Administration (% of construction costs)	15%	LS		$ 84,900
Financing costs				$ 21,225
			Subtotal =	**$ 208,000**
	TOTAL ESTIMATED COST =			**$ 774,000**

Annual Costs			
Administration and Insurance ($0.0033/kWh)	380000	$0.0033	$ 1,254
Operation & Maintenance (Labor)			$ 5,183
Repair and Replacement (Parts and Material), (0.3% of total construction cost)		0.30%	$ 1,698
Subtotal			$ 8,135
Contingency (20%)		20%	$ 1,627
Total O&M			$ 9,762



NOTES:

1. MISC ISOLATION VALVES NOT SHOWN

LEGEND

M MOTORIZED CONTROL VALVE

FM FLOW METER

OAK RIDGE TANKS TO BASS LAKE TANKS PUMPED STORAGE

A1.4 Sandtrap Siphon

PRIORITY:
Recommended for immediate implementation

PURVEYOR LEAD: GDPUD

Project Category: Feed-In Tariff

Design Head (ft): 137

Design Flow (cfs): 24

Nameplate capacity (kW): 230

Estimated Annual MWh/year: 1,130

Photo 4 – Aerial of Walton Reservoir at the Outlet of Sandtrap Siphon

Capital Cost to Construct (Estimated): $1,456,000

Annual Income: $140,752 (assumes 20-year FIT agreement with PG&E; annual revenues cannot be reasonably projected beyond the 20-year analysis period)

EXISTING FEATURES:

Avg. annual flow (cfs)	Distance to 3-phase Power (ft)	Pipeline (in.)	Access Road	Downstream Storage	Land Ownership
17	**500**	**36**	**Y**	**Y**	**GDPUD**

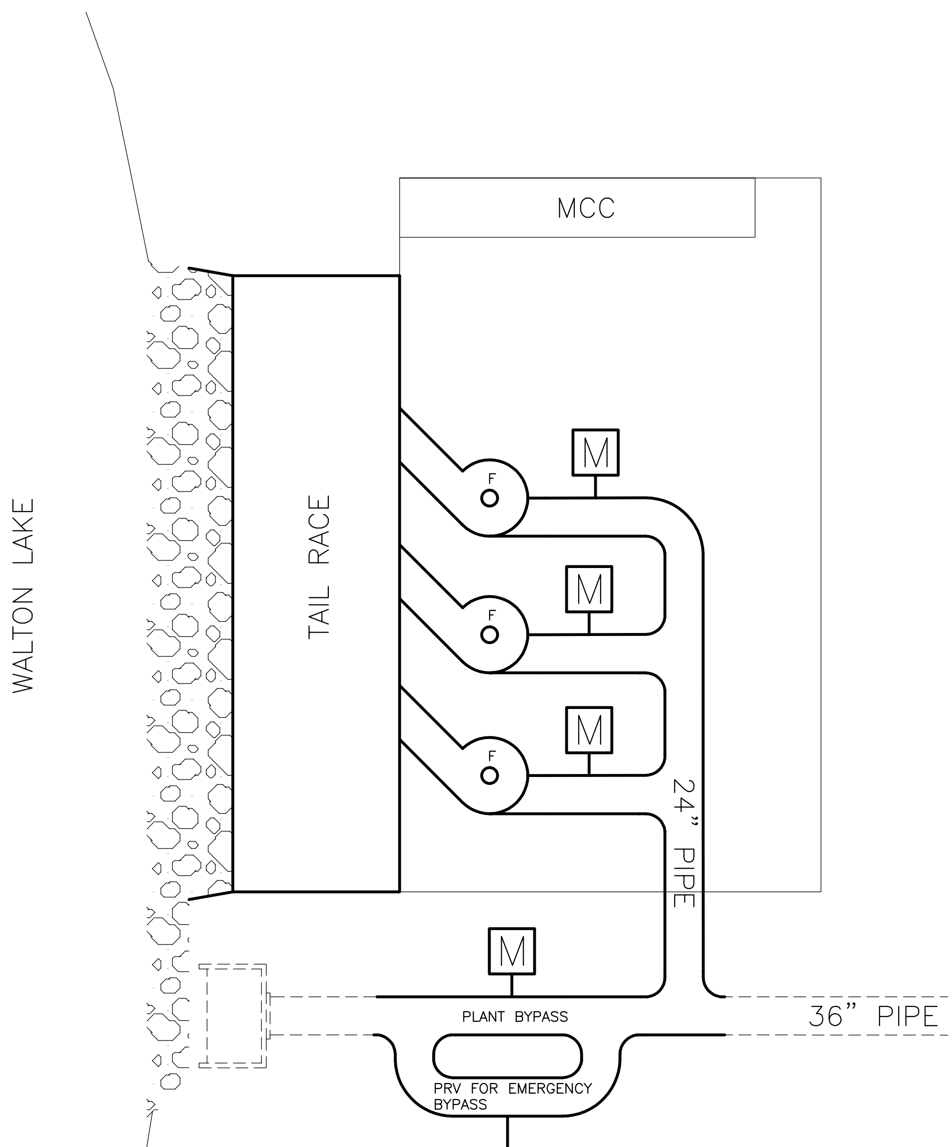
PROJECT DESCRIPTION:

As part of the Stumpy Meadows Project, the GDPUD diverts water at the Pilot Creek Diversion Dam and conveys it in the Georgetown Ditch. The Georgetown Ditch conveyance system includes the inverted Sandtrap Siphon located east of the town of Georgetown. The site is located adjacent to Walton Lake and the Walton Lake Water Treatment Plant, and is within land zoned as commercial. Access to the project is very good. The elevation at the site is approximately 3,100 feet. The project would likely occur within the existing GDPUD easement area, but may require adjacent landowner right-of-way. The Sandtrap hydro option would be located where the Sandtrap Siphon pipeline enters Walton Lake and would include a new 230 kW hydroelectric generating facility, consisting of three units – two fixed and one variable pumps operated as turbines that would collectively have a design flow of 24 cfs. A small powerhouse would be constructed near the Walton Lake shoreline to house the generating equipment. The average annual generation would be approximately 1,130 MWh.

Sandtrap Siphon
Engineer's Preliminary Estimate of Probable Costs

Element Description	Estimated Quantity	Units	Unit Price (installed)	Estimated Amount
Mobilization & Site work				
Mobilization, Bonds, Insurance	1	LS	$ 20,000	$ 20,000
Traffic Control	1	LS	$ 2,500	$ 2,500
Site Grading & Paving & Access	1	LS	$ 40,000	$ 40,000
Fencing	1	LS	$ 10,000	$ 10,000
			Subtotal =	**$ 72,500**
Pipe, Valves and Fittings				
Intake Tie into existing 36" line	1	LS	$ 15,000	$ 15,000
18" In -Line Bypass Valve, piping & vault	1	LS	$ 25,000	$ 25,000
30" pipe to plant	30	LF	$ 245	$ 7,350
Intake Manifold	1	LS	$ 12,000	$ 12,000
16" turbine pipe runs	50	lf	$ 185	$ 9,250
12" motorized control valve	3	EA	$ 9,500	$ 28,500
12" pressure reducing valve	1	EA	$ 8,500	$ 8,500
isolation valves, reducers, misc fittings	1	LS	$ 15,000	$ 15,000
24" flow meter	1	EA	$ 16,000	$ 16,000
			Subtotal =	**$ 136,600**
Turbine/Generator Units				
60 KW Pump as Turbine/Generator Units Installed	3	EA	$ 95,000	$ 285,000
			Subtotal =	**$ 285,000**
Electrical Equipment & Tie-in to Grid				
Electrical Controls/Switchgear for turbine/generator units	1	LS	$ 90,000	$ 90,000
Electrical utility /transformer , misc site electrical	1	LS	$ 70,000	$ 70,000
Hook-up to Grid (power lines, transformers, switches)	1	LS	$ 120,000	$ 120,000
			Subtotal =	**$ 280,000**
Building and Misc Structural				
Masonry building	400	SF	$ 150	$ 60,000
Foundation & Tailrace structure (concrete)	60	CY	$ 550	$ 33,000
Roofing & Misc supports	1	LS	$ 40,000	$ 40,000
			Subtotal =	**$ 133,000**
	Materials/Installation Subtotal =			**$ 907,100**
	15% Construction Contingency Costs=			$ 136,065
	TOTAL CONSTRUCTION COST:			**$ 1,043,000**
Non -Construction Costs				
Admin/Planning/Design/Environmental Docs (% of construction costs)	15%	LS		$ 156,450
Environmental Mitigation (% of construction costs)	10%	LS		$ 104,300
Right of Way Costs	1	AC	$ 30,000	$ 30,000
Construction Administration (% of construction costs)	8%	LS		$ 83,440
Financing Costs				$ 39,113
			Subtotal =	**$ 413,000**
	TOTAL ESTIMATED COST =			**$ 1,456,000**

Annual Costs			
Administration and Insurance ($0.0033/kWh)	970000	$0.0033	$ 3,201
Operation & Maintenance (Labor)			$ 7,058
Repair and Replacement (Parts and Material), (0.3% of total construction cost)		0.30%	$ 3,129
Subtotal			$ 13,388
Contingency (20%)		20%	$ 2,678
Total O&M			$ 16,065



hs = 140ft
TDH = 120ft
Qsummer = 30cfs
Qwinter = 3–10cfs

NOTES:

1. MISC ISOLATION VALVES NOT SHOWN

LEGEND

$\boxed{M}$ MOTORIZED CONTROL VALVE

F FIXED SPEED TURBINE (10 CFS)

SANDTRAP SIPHON

A1.5 Buffalo Hill Siphon

Photo 5 – Outlet Structure at Buffalo Hill Siphon

PRIORITY:
Recommended for reoperation study

PURVEYOR LEAD: GDPUD

Project Category: Feed-In Tariff

Design Head (ft): 141

Design Flow (cfs): 20

Nameplate capacity (kW): 170

Estimated Annual MWh/year: 860

Capital Cost to Construct (Estimated): $1,284,000

Annual Income: $106,777 (assumes 20-year FIT agreement with PG&E; annual revenues cannot be reasonably projected beyond the 20-year analysis period)

EXISTING FEATURES:

Avg. annual flow (cfs)	Distance to 3-phase Power (ft)	Pipeline (in.)	Access Road	Downstream Storage	Land Ownership
15	**300**	**24**	**Y**	**N**	**GDPUD**

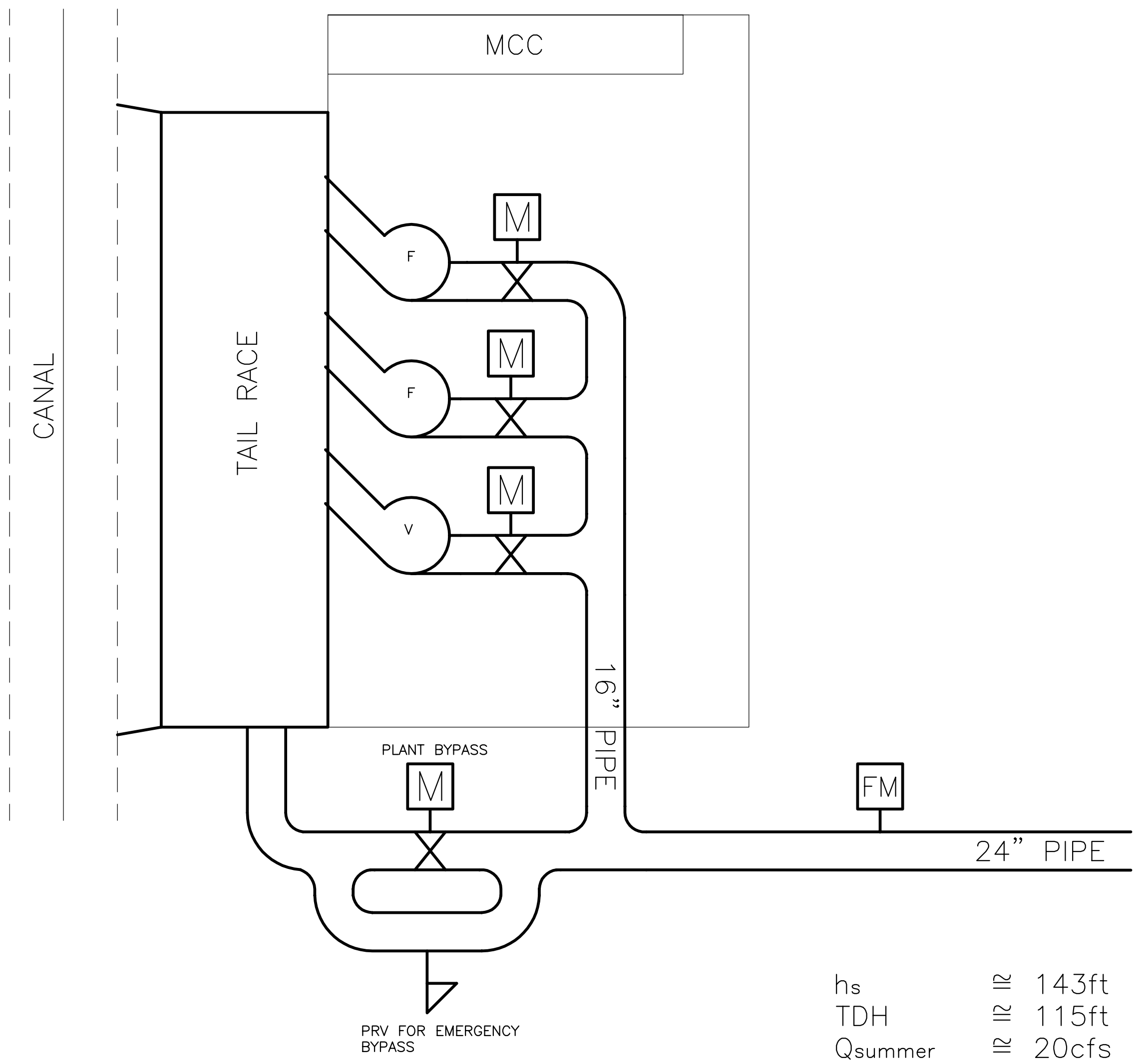
PROJECT DESCRIPTION:

The Buffalo Hill inverted siphon is located on the Georgetown Ditch conveyance system just north of the town of Georgetown, near Highway 193. The Buffalo Hill Siphon hydro option would capture the energy available at the existing 24-inch Buffalo Hill Siphon with a 170 kW hydroelectric generating facility located near the energy dissipating structure at the terminus of the siphon. The project would be sized for a maximum flow of 20 cfs, which approximates the peak flows between May and October. Annual flows are expected to average 12 cfs due to lower demand in the winter. The operating head would be variable, depending on flow rate, but is expected to average about 115 feet (141 feet max.). The project would operate using existing and future water supplies required by the GDPUD distribution system. No reoperation of the Stumpy Meadows Project or the Georgetown Ditch is expected. The average annual generation expected from the Buffalo Hill Siphon option is about 860 MWh.

Buffalo Hill Siphon
Engineer's Preliminary Estimate of Probable Costs

Element Description	Estimated Quantity	Units	Unit Price (installed)		Estimated Amount	
Mobilization & Site work						
Mobilization, Bonds, Insurance	1	LS	$	20,000	$	20,000
Traffic Control	1	LS	$	2,500	$	2,500
Site Grading & Paving & Access	1	LS	$	20,000	$	20,000
Fencing	1	LS	$	10,000	$	10,000
				Subtotal =	**$**	**52,500**
Pipe, Valves and Fittings						
Intake Tie into existing 24" line	1	LS	$	12,500	$	12,500
18" In -Line Bypass Valve, piping & vault	1	LS	$	25,000	$	25,000
24" pipe to plant	30	LF	$	200	$	6,000
Intake Manifold	1	LS	$	12,000	$	12,000
16" turbine pipe runs	50	lf	$	185	$	9,250
12" motorized control valve	3	EA	$	9,500	$	28,500
12" pressure reducing valve	1	EA	$	8,500	$	8,500
isolation valves, reducers, misc fittings	1	LS	$	15,000	$	15,000
24" flow meter	1	EA	$	16,000	$	16,000
				Subtotal =	**$**	**132,750**
Turbine/Generator Units						
60 KW Pump as Turbine/Generator Units Installed	3	EA	$	95,000	$	285,000
				Subtotal =	**$**	**285,000**
Electrical Equipment & Tie-in to Grid						
Electrical Controls/Switchgear for turbine/generator units	1	LS	$	90,000	$	90,000
Electrical utility /transformer , misc site electrical	1	LS	$	70,000	$	70,000
Hook-up to Grid (power lines, transformers, switches)	1	LS	$	60,000	$	60,000
				Subtotal =	**$**	**220,000**
Building and Misc Structural						
Masonry building	400	SF	$	150	$	60,000
Foundation & Tailrace structure (concrete)	60	CY	$	550	$	33,000
Roofing & Misc supports	1	LS	$	40,000	$	40,000
				Subtotal =	**$**	**133,000**
	Materials/Installation Subtotal =				**$**	**823,250**
	15% Construction Contingency Costs=				$	123,488
	TOTAL CONSTRUCTION COST:				**$**	**947,000**
Non -Construction Costs						
Admin/Planning/Design/Environmental Docs (% of construction costs)	15%	LS			$	142,050
Environmental Mitigation (% of construction costs)	8%	LS			$	75,760
Right of Way Costs	0.25	AC	$	30,000	$	7,500
Construction Administration (% of construction costs)	8%	LS			$	75,760
Financing Costs					$	35,513
				Subtotal =	**$**	**337,000**
	TOTAL ESTIMATED COST =				**$**	**1,284,000**

Annual Costs				
Administration and Insurance ($0.0033/kWh)	760000	$0.0033	$	2,508
Operation & Maintenance (Labor)			$	7,058
Repair and Replacement (Parts and Material), (0.3% of total construction cost)		0.30%	$	2,841
Subtotal			$	12,407
Contingency (20%)		20%	$	2,481
Total O&M			$	14,888



h_s	≅	143ft
TDH	≅	115ft
Q_{summer}	≅	20cfs
Q_{winter}	≅	3–10cfs

NOTES:

1. MISC ISOLATION VALVES NOT SHOWN

LEGEND

M MOTORIZED CONTROL VALVE

FM FLOW METER

F FIXED SPEED TURBINE (6 TO 10 CFS)

V VARIABLE SPEED TURBINE

BUFFALO HILL SIPHON

A1.6 Kaiser Siphon

PRIORITY:
Recommended for immediate implementation

PURVEYOR LEAD: GDPUD

Project Category: FIT (to be confirmed)

Design Head (ft): 668

Design Flow (cfs): 15

Nameplate capacity (kW): 580

Estimated Annual MWh/year: 3,638

Photo 6 – Aerial of Approximate Pipeline Alignment (shown in green)

Capital Cost to Construct (Estimated): $5,172,000 (includes Oblique Aerial of Kaiser Siphon Area 8,000-foot pipeline)

Annual Income: $448,331 (assumes 20-year FIT agreement with PG&E; annual revenues cannot be reasonably projected beyond the 20-year analysis period)

EXISTING FEATURES:

Avg. annual flow (cfs)	Distance to 3-phase Power (ft)	Pipeline (in.)	Access Road	Downstream Storage	Land Ownership
10	**1,200**	**24**	**Y**	**N**	**GDPUD/Priv.**

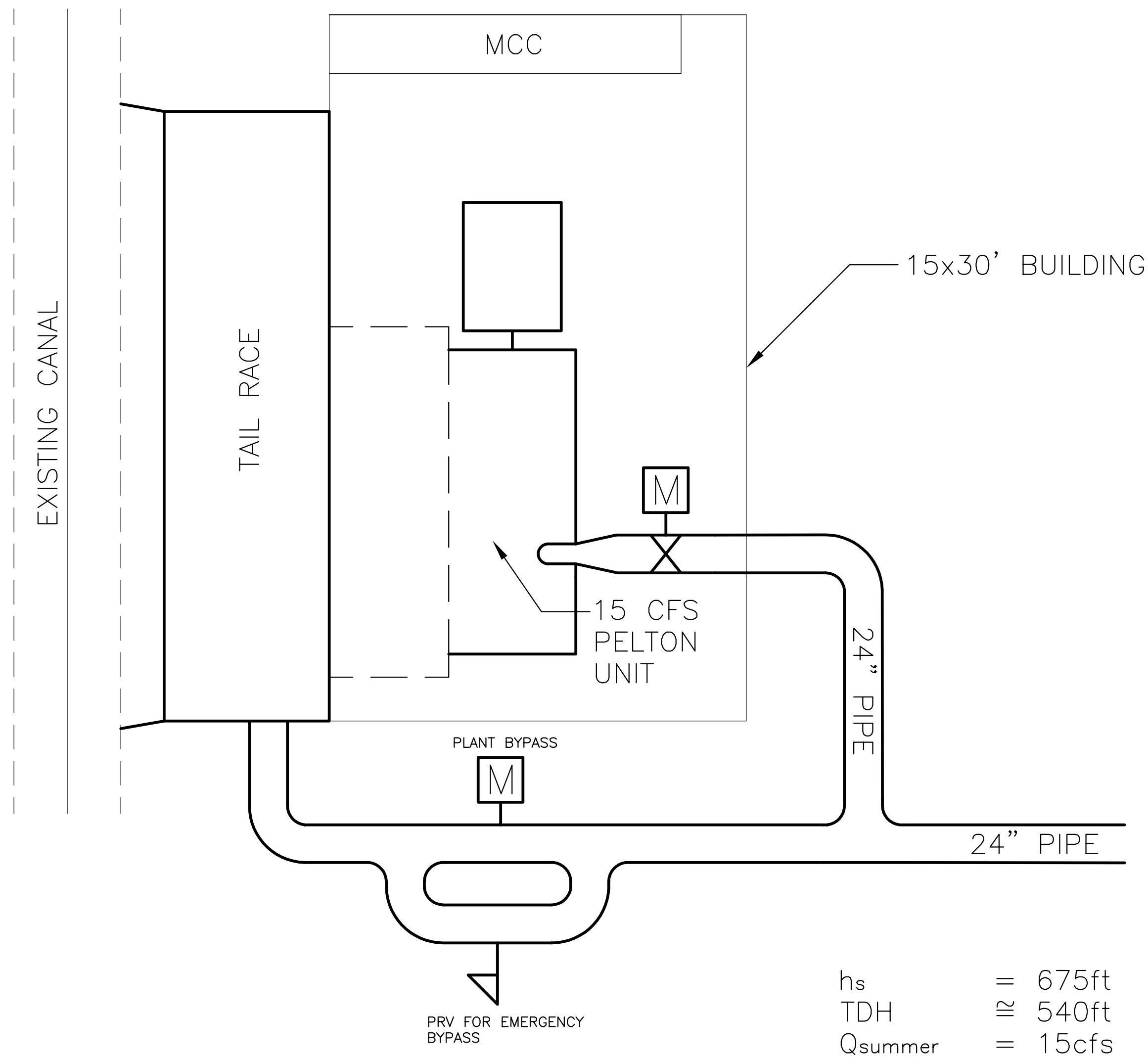
PROJECT DESCRIPTION:

The Kaiser inverted siphon is located on the Georgetown Ditch conveyance system near Highway 193 just north of Greenwood, near the Auburn Lake Trails Water Treatment Plant. The existing siphon is a 24-inch diameter buried pipeline that flows to an energy dissipater at its terminus. This project option includes replacing an existing reinforced plastic mortar (Techite) pipe and an open channel section upstream of the siphon with new, 24-inch diameter pipe, for a total distance of 8,000 feet. The extended pipe provides for a significant increase in available head and resulting project benefit. The proposed 580 kW generating facility would be located immediately adjacent to and downstream from the existing energy dissipating structure. The project is sized for an estimated maximum flow of 15 cfs, which would occur between May and October. Annual flows are expected to average 10 cfs due to lower demand in the winter. The operating head would be variable, depending on flow rate, but is expected to average about 540 feet. The proposed project would operate using existing and future water supplies required by the GDPUD distribution system. No reoperation of the Stumpy Meadows Project or the Georgetown Ditch is expected. The average annual generation expected from the Kaiser Siphon hydroelectric project is about 3,600 MWh.

Kaiser Siphon
Engineer's Preliminary Estimate of Probable Costs

Element Description	Estimated Quantity	Units	Unit Price (installed)		Estimated Amount
Mobilization & Site work					
Mobilization, Bonds, Insurance	1	LS	$ 25,000	$	25,000
Traffic Control	1	LS	$ 2,000	$	2,000
Site Grading & Paving & Access	1	LS	$ 20,000	$	20,000
Fencing	1	LS	$ 10,000	$	10,000
			Subtotal =	**$**	**57,000**
Pipe, Valves and Fittings					
New 24" pipeline in existing ditch	8,000	LF	$ 200	$	1,600,000
Temporary Service Pipeline	8,300	LF	$ 50	$	415,000
Replace techite section	300	LF	$ 230	$	69,000
Tie into new 24" line	1	LS	$ 12,000	$	12,000
24" In -Line Bypass Valve, piping & vault	1	LS	$ 32,000	$	32,000
24" pipe to plant	40	LF	$ 200	$	8,000
Intake Manifold	1	LS	$ 9,000	$	9,000
18" motorized control valve	1	EA	$ 25,000	$	25,000
isolation valves, reducers, misc fittings	1	LS	$ 15,000	$	15,000
			Subtotal =	**$**	**2,185,000**
Turbine/Generator Units					
580 KW Pelton Turbine/Gen Installed	1	EA	$ 580,000	$	580,000
			Subtotal =	**$**	**580,000**
Electrical Equipment & Tie-in to Grid					
Electrical Controls/Switchgear for turbine/generator units	1	LS	$ 95,000	$	95,000
Electrical utility /transformer , misc site electrical	1	LS	$ 80,000	$	80,000
Hook-up to Grid (power lines, transformers, switches)	1	LS	$ 120,000	$	120,000
			Subtotal =	**$**	**295,000**
Building and Misc Structural					
Masonry building	600	SF	$ 150	$	90,000
Foundation & tailrace structure (concrete)	120	CY	$ 550	$	66,000
Roofing & Misc supports	1	LS	$ 40,000	$	40,000
			Subtotal =	**$**	**196,000**
	Materials/Installation Subtotal =			**$**	**3,313,000**
	15% Construction Contingency Costs=			$	496,950
	TOTAL CONSTRUCTION COST:			**$**	**3,810,000**
Non -Construction Costs					
Admin/Planning/Design/Environmental Docs (% of construction costs)	15%	LS		$	571,500
Environmental Mitigation (% of construction costs)	10%	LS		$	381,000
Right of Way Costs	3.5	AC	$ 30,000	$	105,000
Construction Administration (% of construction costs)	8%	LS		$	304,800
Financing Costs				$	238,125
			Subtotal =	**$**	**1,362,000**
	TOTAL ESTIMATED COST =			**$**	**5,172,000**

Annual Costs				
Administration and Insurance ($0.0033/kWh)	3600000	$0.0033	$	11,880
Operation & Maintenance (Labor)			$	6,558
Repair and Replacement (Parts and Material), (0.3% of total construction cost)		0.30%	$	6,630
Subtotal			$	25,068
Contingency (20%)		20%	$	5,014
Total O&M			$	30,081



NOTES:

1. MISC ISOLATION VALVES NOT SHOWN

LEGEND

$\boxed{M}$ MOTORIZED CONTROL VALVE

KAISER SIPHON

A1.7 Sly Park Dam

PRIORITY:
Recommended for immediate implementation

PURVEYOR LEAD: EID

Project Category: Feed-In Tariff

Design Head (ft): 95

Design Flow (cfs): 55

Nameplate capacity (kW): 400

Estimated Annual MWh/year: 1,833

Photo 7 – Sly Park Dam, Hydroelectric Project at Dam Section on Right

Capital Cost to Construct (Estimated): $2,571,000

Annual Income: $227,978 (assumes 20-year FIT agreement with PG&E; annual revenues cannot be reasonably projected beyond the 20-year analysis period)

EXISTING FEATURES:

Avg. annual flow (cfs)	Distance to 3-phase Power (ft)	Pipeline (in.)	Access Road	Downstream Storage	Land Ownership
75	**1,000**	**48**	**Y**	**N**	**EID**

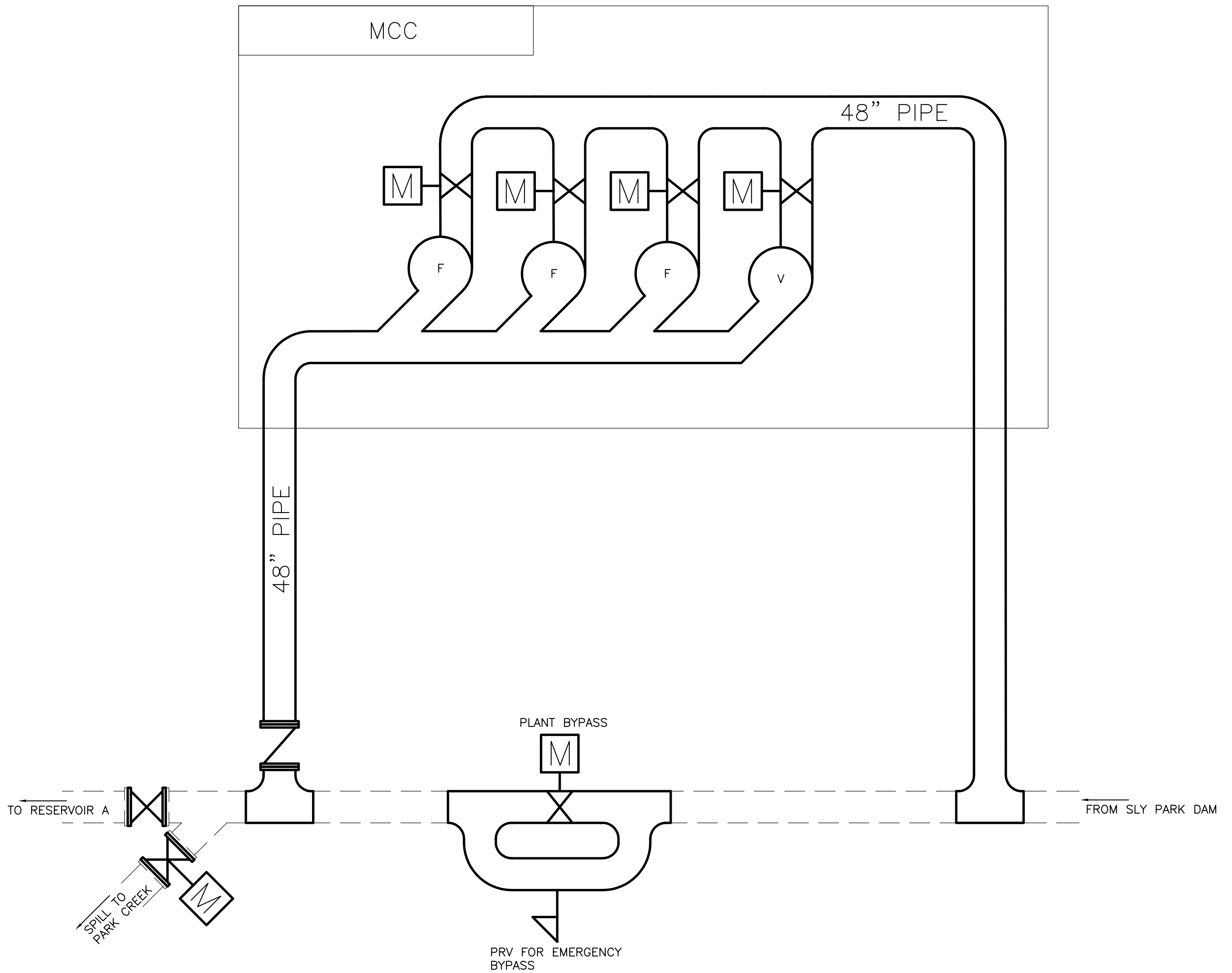
PROJECT DESCRIPTION:

The Sly Park Dam hydro option would replace a pressure reducing valve (PRV) on the dam outlet works with a hydroelectric facility that has at least two operational sub-options. Sly Park Dam impounds Jenkinson Lake just to the southeast of Pollock Pines. The main dam is approximately 176 feet high with a crest length of 760 feet and elevation 3,482 feet. The first option would generate power from the Camino Conduit flows. The second option would add Jenkinson spillway flows. This is a FIT project with good road access and relatively close proximity to existing transmission lines. Power generation from the first option is expected to be approximately 1,800 MWh per year using four vertical turbine PATs.

Sly Park Dam
Engineer's Preliminary Estimate of Probable Costs

Element Description	Estimated Quantity	Units	Unit Price (installed)		Estimated Amount
Mobilization & Site work					
Mobilization, Bonds, Insurance	1	LS	$ 20,000	$	20,000
Traffic Control	0	LS	$ 2,500	$	-
Site Grading & Paving & Access	1	LS	$ 75,000	$	75,000
Fencing	1	LS	$ 15,000	$	15,000
			Subtotal =	**$**	**110,000**
Pipe, Valves and Fittings					
Tie into Existing 48" pipe (station inlet and outlet)	1	LS	$ 45,000	$	45,000
48" Bypass Valve & Piping	1	LS	$ 45,000	$	45,000
48" Plant pipe	40	LF	$ 320	$	12,800
18" turbine pipe runs	45	LF	$ 265	$	11,925
18" motorized control valve	3	EA	$ 15,000	$	45,000
36" turbine pipe run	20	LF	$ 285	$	5,700
36" motorized control valve	1	EA	$ 32,000	$	32,000
isolation valves, reducers, misc fittings	1	LS	$ 45,000	$	45,000
Spill outfall pipe and valve	1	LS	$ 50,000	$	50,000
48" flow meter	1	EA	$ 36,000	$	36,000
			Subtotal =	**$**	**328,425**
Turbine/Generator Units					
100 KW Pump as Turbine/Generator Units Installed	4	EA	$ 118,000	$	472,000
			Subtotal=	**$**	**472,000**
Electrical Equipment & Tie-in to Grid					
Electrical Controls/Switchgear for turbine/generator units	1	LS	$ 250,000	$	250,000
Electrical utility /transformer , misc site electrical	1	LS	$ 145,000	$	145,000
Hook-up to Grid (power lines, transformers, switches)	1	LS	$ 60,000	$	60,000
			Subtotal =	**$**	**455,000**
Building and Misc Structural					
Masonry building (30'x40')	1,200	SF	$ 150	$	180,000
Foundation	25	CY	$ 550	$	13,750
Roofing & Misc supports	1	LS	$ 50,000	$	50,000
Outfall erosion control	1	LS	$ 30,000	$	30,000
			Subtotal =	**$**	**273,750**
	Materials/Installation Subtotal =			**$**	**1,639,175**
	15% Construction Contingency Costs=			$	245,876
	TOTAL CONSTRUCTION COST:			**$**	**1,885,000**
Non -Construction Costs					
Admin/Planning/Design/Environmental Docs (% of construction costs)	15%	LS		$	282,750
Environmental Mitigation (% of construction costs)	8%	LS		$	150,800
Right of Way Costs	0.25	AC	$ 30,000	$	7,500
Construction Administration (% of construction costs)	8%	LS		$	150,800
Financing costs				$	94,250
			Subtotal =	**$**	**686,000**
	TOTAL ESTIMATED COST =			**$**	**2,571,000**

Annual Costs				
Administration and Insurance ($0.0033/kWh)	1800000	$0.0033	$	5,940
Operation & Maintenance (Labor)			$	7,411
Repair and Replacement (Parts and Material), (0.3% of total construction cost)		0.30%	$	5,655
Subtotal			$	19,006
Contingency (20%)		20%	$	3,801
Total O&M			$	22,807



NOTES:

1. MISC ISOLATION VALVES NOT SHOWN

LEGEND

M	MOTORIZED CONTROL VALVE
F	FIXED SPEED TURBINE (15 CFS)
V	VARIABLE SPEED TURBINE

SLY PARK DAM

A1.8 Pleasant Oak Main (Reservoir B)

Photo 8 – Existing Pressure Reducing Station at Reservoir B

PRIORITY:
Recommended for immediate implementation

PURVEYOR LEAD: EID

Project Category: Feed-In Tariff (2-plants)

Design Heads (ft): 139/199

Design Flow (cfs): 24

Nameplate capacities (kW): 180/ 270

Estimated Annual MWh/year: 2,657

Capital Cost to Construct (Estimated): $3,591,000

Annual Income: $326,980 (assumes 20-year FIT agreement with PG&E; annual revenues cannot be reasonably projected beyond the 20-year analysis period)

EXISTING FEATURES:

Avg. annual flow (cfs)	Distance to 3-phase Power (ft)	Pipeline (in.)	Access Road	Downstream Storage	Land Ownership
16	**10,000**	**36**	**Y**	**Y**	**EID**

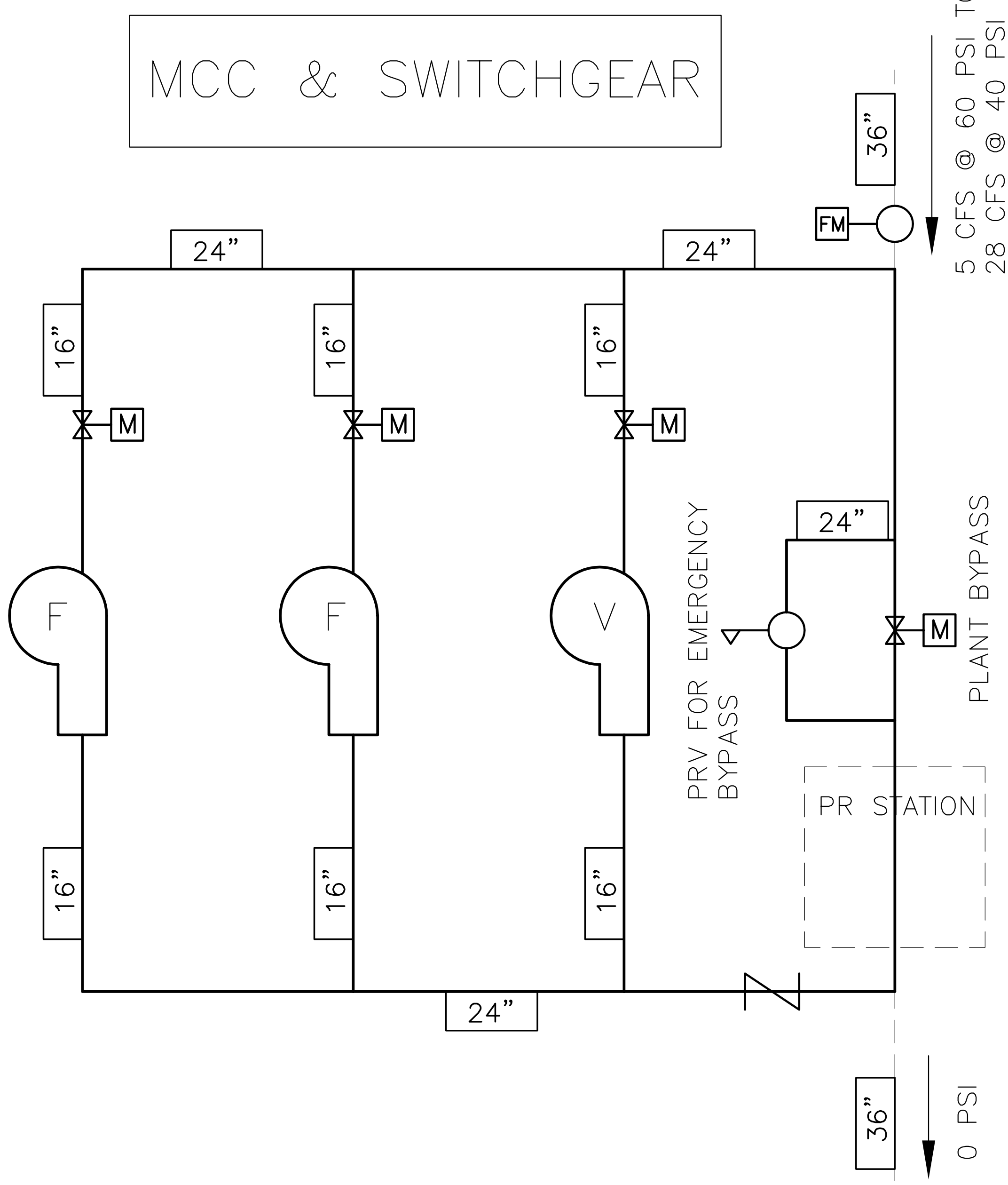
PROJECT DESCRIPTION:

The Pleasant Oak Main (POM) at Reservoir B hydro option is a dual station project, located off of Pleasant Valley Road. One unit would be upstream at the Reservoir B site and one unit downstream (west) of Reservoir B along the District access road. The two stations would share transmission line facilities and the same flow rates through the POM pipeline. The two sites are relatively flat and have good construction access. There is sufficient area on the Reservoir B site for the proposed project. The second site may require a small amount of new right-of-way adjacent to the District's access road to Reservoir B. 3-phase transmission lines are approximately 10,000 feet from the furthest unit. The two hydro stations would be located on the existing 36-inch pipeline. Each hydro station will have three PATs with one turbine operating at variable speed with a regenerative power converter. Each hydro station will be housed in a masonry building approximately 400 square feet in area. The combined power generating capacity of the two hydro stations is projected to be about 2,600 MWh per year.

Pleasant Oak Main (Reservoir B)
Engineer's Preliminary Estimate of Probable Costs

Element Description	Estimated Quantity	Units	Unit Price (installed)		Estimated Amount
Mobilization & Site work (combined)					
Mobilization, Bonds, Insurance	1	LS	$ 40,000	$	40,000
Traffic Control	1	LS	$ 2,000	$	2,000
Site Grading & Paving & Access	1	LS	$ 55,000	$	55,000
Fencing	1	LS	$ 15,000	$	15,000
			Subtotal =	**$**	**112,000**
Pipe, Valves and Fittings (plant 1)					
Intake and Return Tie into existing 36" line (Including de-water of pipe)	1	LS	$ 33,000	$	33,000
24" In -Line Bypass Valve, piping & vault	1	LS	$ 32,000	$	32,000
24" pipe to and from plant	60	LF	$ 200	$	12,000
Intake and Return Manifolds	1	LS	$ 20,000	$	20,000
16" turbine pipe runs	50	lf	$ 185	$	9,250
12" motorized control valve	3	EA	$ 9,500	$	28,500
12" pressure reducing valve	1	EA	$ 8,500	$	8,500
24" check valve	1	EA	$ 11,000	$	11,000
isolation valves, reducers, misc fittings	1	LS	$ 22,000	$	22,000
24" flow meter	1	EA	$ 16,000	$	16,000
Pipe, Valves and Fittings (plant 2)	**1**	**LS**	**$ 192,250**	**$**	**192,250**
			Subtotal =	**$**	**384,500**
Turbine/Generator Units (combined)					
90 KW Pump as Turbine/Generator Units Installed	3	EA	$ 115,000	$	345,000
60 KW Pump as Turbine/Generator Units Installed	3	EA	$ 90,000	$	270,000
			Subtotal =	**$**	**615,000**
Electrical Equipment & Tie-in to Grid(combined)					
Electrical Controls/Switchgear for turbine/generator units	1	LS	$ 220,000	$	220,000
Electrical utility /transformer , misc site electrical	1	LS	$ 180,000	$	180,000
Hook-up to Grid (power lines, transformers, switches)	1	LS	$ 550,000	$	550,000
			Subtotal =	**$**	**950,000**
Building and Misc Structural (combined)					
Masonry building	800	SF	$ 150	$	120,000
Foundation structure (concrete)	16	CY	$ 550	$	8,800
Roofing & Misc supports	1	LS	$ 80,000	$	80,000
			Subtotal =	**$**	**208,800**
	Materials/Installation Subtotal =			**$**	**2,270,300**
	15% Construction Contingency Costs=			$	340,545
	TOTAL CONSTRUCTION COST:			**$**	**2,611,000**
Non -Construction Costs					
Admin/Planning/Design/Environmental Docs (% of construction costs)	15%	LS		$	391,650
Environmental Mitigation (% of construction costs)	8%	LS		$	208,880
Right of Way Costs	0.25	AC	$ 30,000	$	7,500
Construction Administration (% of construction costs)	8%	LS		$	208,880
Financing Cost				$	163,188
			Subtotal =	**$**	**980,000**
		TOTAL ESTIMATED COST =		**$**	**3,591,000**

Annual Costs				
Administration and Insurance ($0.0033/kWh)	2600000	$0.0033	$	8,580
Operation & Maintenance (Labor)			$	7,058
Repair and Replacement (Parts and Material), (0.3% of total construction cost)		0.30%	$	7,833
Subtotal			$	23,471
Contingency (20%)		20%	$	4,694
Total O&M			$	28,165

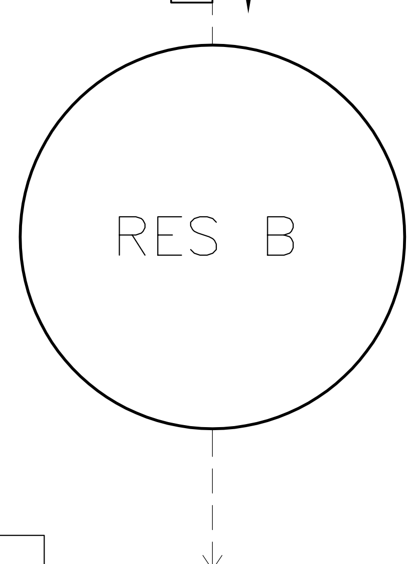


NOTES:

1. MISC ISOLATION VALVES NOT SHOWN

LEGEND

M	MOTORIZED CONTROL VALVE
FM	FLOW METER
F	FIXED SPEED TURBINE (8 TO 12 CFS)
V	VARIABLE SPEED TURBINE



PLEASANT OAK MAIN (RESERVOIR B)

A1.9 Pleasant Oak Main PRS 5 (Reservoir 7)

PRIORITY:
Recommended for immediate implementation

PURVEYOR LEAD: EID

Project Category: Feed-In Tariff

Design Head (ft): 340

Design Flow (cfs): 24

Nameplate capacity (kW): 510

Estimated Annual MWh/year: 2,321

Photo 9 – Tanks and Pressure Reducing Station at Reservoir 7

Capital Cost to Construct (Estimated): $1,523,000

Annual Income: $287,082 (assumes 20-year FIT agreement with PG&E; annual revenues cannot be reasonably projected beyond the 20-year analysis period)

EXISTING FEATURES:

Avg. annual flow (cfs)	Distance to 3-phase Power (ft)	Pipeline (in.)	Access Road	Downstream Storage	Land Ownership
14	**40**	**24**	**Y**	**Y**	**EID**

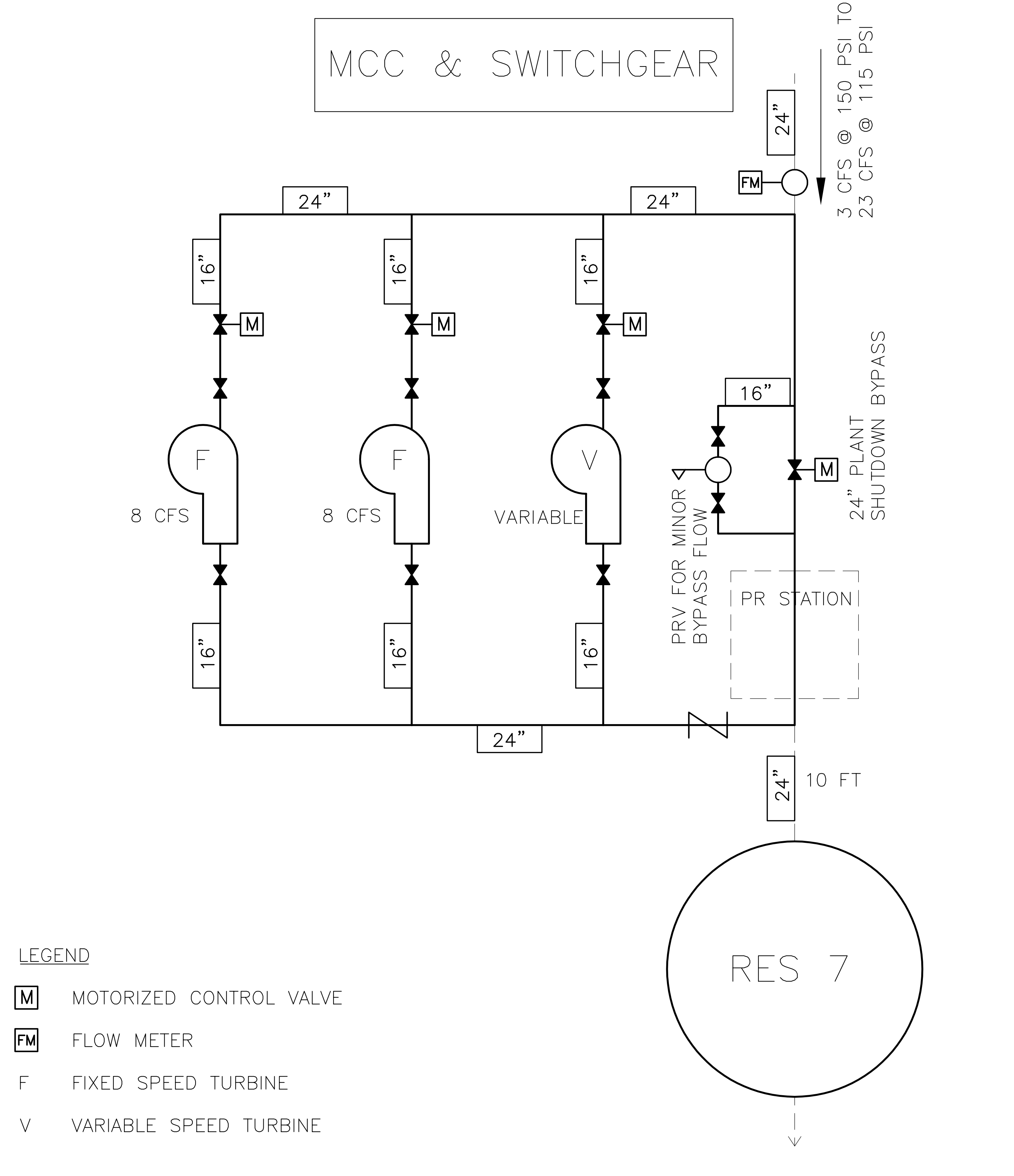
PROJECT DESCRIPTION:

The POM Pressure Reducing Station 5 (PRS 5) hydro option would be located on the northeast side of the Reservoir 7 tank site, off of Pleasant Valley Road. There is sufficient area on the existing site for the proposed project. The site is situated at approximately 2,230 feet elevation, is relatively flat, and has good construction access. The surrounding land use is low density residential and open space. The hydro station will consist of three PATs with one turbine operating at variable speed with a regenerative power converter. The facilities will be housed in a masonry building approximately 400 square feet in area. Minor changes in operations for delivery of flow to Reservoir 7 can smooth out the variability of the flow which can result in less complicated control, greater generation, and less potential wear on the hydro station components. Annual power generation is expected to be approximately 2,300 MWh.

Pleasant Oak Main PRS5 (Reservoir 7)
Engineer's Preliminary Estimate of Probable Costs

Element Description	Estimated Quantity	Units	Unit Price (installed)		Estimated Amount
Mobilization & Site work					
Mobilization, Bonds, Insurance	1	LS	$ 20,000	$	20,000
Traffic Control	1	LS	$ 3,000	$	3,000
Site Grading & Paving & Access	1	LS	$ 18,000	$	18,000
Fencing	0	LS	$ 10,000	$	-
			Subtotal =	**$**	**41,000**
Pipe, Valves and Fittings					
Intake and Return Tie into existing 30" line (Including de-water of pipe)	1	LS	$ 30,000	$	30,000
24" In -Line Bypass Valve, piping & vault	1	LS	$ 32,000	$	32,000
24" pipe to and from plant	60	LF	$ 200	$	12,000
Intake and Return Manifolds	1	LS	$ 20,000	$	20,000
16" turbine pipe runs	50	lf	$ 185	$	9,250
12" motorized control valve	3	EA	$ 9,500	$	28,500
12" pressure reducing valve	1	EA	$ 8,500	$	8,500
24" check valve	1	EA	$ 11,000	$	11,000
isolation valves, reducers, misc fittings	1	LS	$ 22,000	$	22,000
24" flow meter	1	EA	$ 16,000	$	16,000
			Subtotal =	**$**	**189,250**
Turbine/Generator Units					
170 KW Pump as Turbine/Generator Units Installed	3	EA	$ 140,000	$	420,000
			Subtotal =	**$**	**420,000**
Electrical Equipment & Tie-in to Grid					
Electrical Controls/Switchgear for turbine/generator units	1	LS	$ 120,000	$	120,000
Electrical utility /transformer , misc site electrical	1	LS	$ 95,000	$	95,000
Hook-up to Grid (power lines, transformers, switches)	1	LS	$ 4,000	$	4,000
			Subtotal =	**$**	**219,000**
Building and Misc Structural					
Masonry building	400	SF	$ 150	$	60,000
Foundation structure (concrete)	8	CY	$ 550	$	4,400
Roofing & Misc supports	1	LS	$ 40,000	$	40,000
			Subtotal =	**$**	**104,400**
	Materials/Installation Subtotal =			**$**	**973,650**
	15% Construction Contingency Costs=			$	146,048
	TOTAL CONSTRUCTION COST:			**$**	**1,120,000**
Non -Construction Costs					
Admin/Planning/Design/Environmental Docs (% of construction costs)	15%	LS		$	168,000
Environmental Mitigation (% of construction costs)	8%	LS		$	89,600
Right of Way Costs		AC	$ 30,000	$	-
Construction Administration (% of construction costs)	8%	LS		$	89,600
Financing costs				$	56,000
			Subtotal =	**$**	**403,000**
	TOTAL ESTIMATED COST =			**$**	**1,523,000**

Annual Costs				
Administration and Insurance ($0.0033/kWh)	2300000	$0.0033	$	7,590
Operation & Maintenance (Labor)			$	7,058
Repair and Replacement (Parts and Material), (0.3% of total construction cost)		0.30%	$	3,360
Subtotal			$	18,008
Contingency (20%)		20%	$	3,602
Total O&M			$	21,609



PLEASANT OAK MAIN PRS 5 (RESERVOIR 7)

A1.10 Diamond Springs Main PRS 1 (Reservoir 8)

PRIORITY:
Recommended for reoperation study

PURVEYOR LEAD: EID

Project Category: Feed-In Tariff

Design Head (ft): 136

Design Flow (cfs): 17

Nameplate capacity (kW): 140

Estimated Annual MWh/year: 690

Capital Cost to Construct (Estimated):
$1,082,000

Photo 10 – DSM Pressure Reducing Station No.1

Annual Income: $82,196 (assumes 20-year FIT agreement with PG&E; annual revenues cannot be reasonably projected beyond the 20-year analysis period)

EXISTING FEATURES:

Avg. annual flow (cfs)	Distance to 3-phase Power (ft)	Pipeline (in.)	Access Road	Downstream Storage	Land Ownership
11	**40**	**24**	**Y**	**N**	**EID**

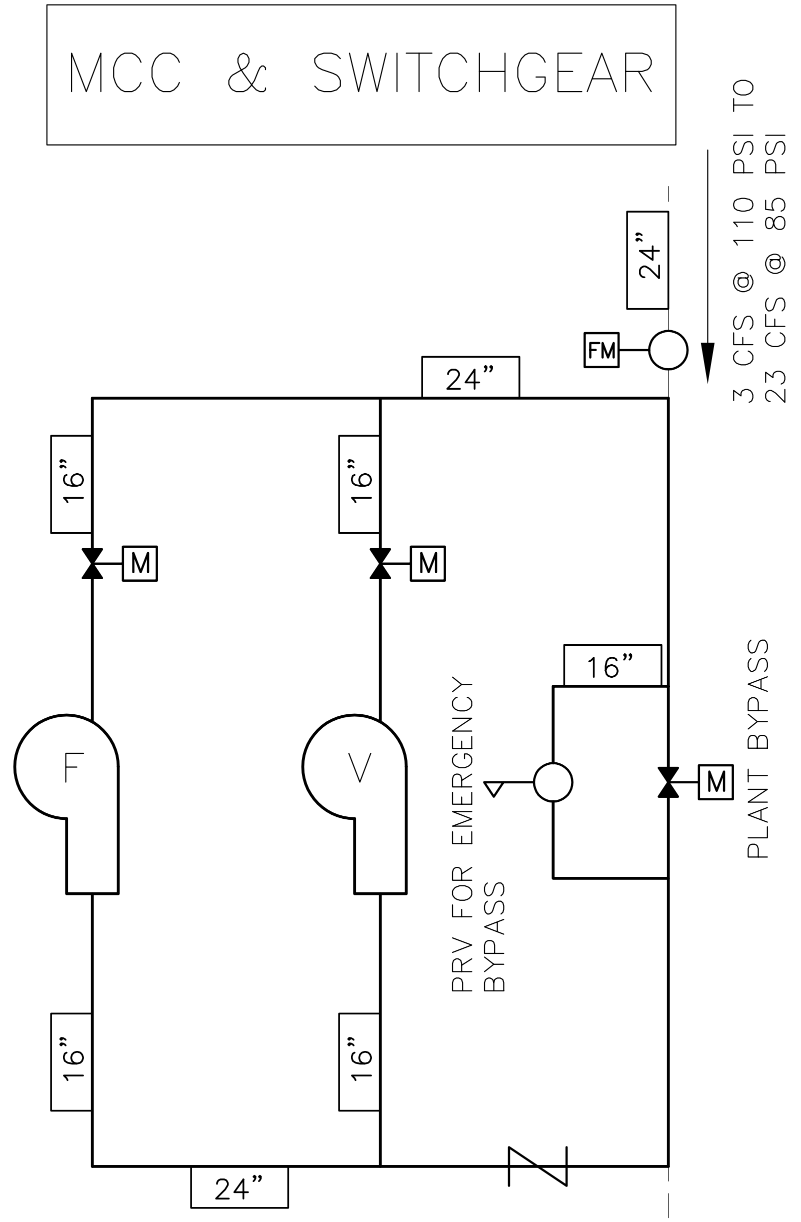
PROJECT DESCRIPTION:

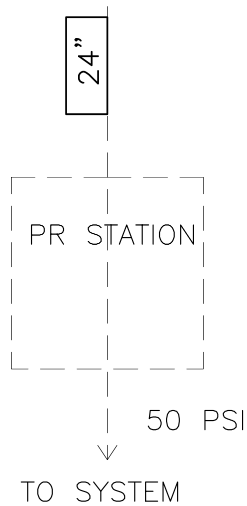
This project is at an existing pressure reducing (PR) station on EID's Diamond Springs Main at the old Reservoir 8 Site. The site, at an elevation of 2,080 feet, is relatively flat and has good construction access. The surrounding land use is low and medium density residential and open space. The hydro station will consist of two PATs with one turbine operating at variable speed with a regenerative power converter. The energy production is moderate (690 MWh) when compared to some of the other more favorable sites due to less head and flow. As with many of the PR sites, onsite storage is not available to regulate flows, requiring flow regulation through multiple units and valve controls. However, access and distance to power grid are reasonable. The proposed facilities would be housed in a masonry building approximately 230 square feet in area.

Diamond Springs Main PRS 1 (Reservoir 8)
Engineer's Preliminary Estimate of Probable Costs

Element Description	Estimated Quantity	Units	Unit Price (installed)	Estimated Amount
Mobilization & Site work				
Mobilization, Bonds, Insurance	1	LS	$ 25,000	$ 25,000
Traffic Control	1	LS	$ 3,000	$ 3,000
Site Grading & Paving & Access	1	LS	$ 25,000	$ 25,000
Fencing	1	LS	$ 10,000	$ 10,000
			Subtotal =	**$ 63,000**
Pipe, Valves and Fittings				
Intake and Return Tie into existing 24" line (Including de-water of pipe)	1	LS	$ 25,000	$ 25,000
24" In -Line Bypass Valve, piping & vault	1	LS	$ 32,000	$ 32,000
24" pipe to and from plant	45	LF	$ 200	$ 9,000
Intake and Return Manifolds	1	LS	$ 20,000	$ 20,000
12" turbine pipe runs	30	lf	$ 155	$ 4,650
12" motorized control valve	2	EA	$ 9,500	$ 19,000
12" pressure reducing valve	1	EA	$ 8,500	$ 8,500
24" check valve	1	EA	$ 11,000	$ 11,000
isolation valves, reducers, misc fittings	1	LS	$ 22,000	$ 22,000
18" flow meter	1	EA	$ 12,000	$ 12,000
			Subtotal =	**$ 163,150**
Turbine/Generator Units				
70 KW Pump as Turbine/Generator Units Installed	2	EA	$ 95,000	$ 190,000
			Subtotal =	**$ 190,000**
Electrical Equipment & Tie-in to Grid				
Electrical Controls/Switchgear for turbine/generator units	1	LS	$ 100,000	$ 100,000
Electrical utility /transformer , misc site electrical	1	LS	$ 90,000	$ 90,000
Hook-up to Grid (power lines, transformers, switches)	1	LS	$ 4,000	$ 4,000
			Subtotal =	**$ 194,000**
Building and Misc Structural				
Masonry building	230	SF	$ 150	$ 34,500
Foundation structure (concrete)	8	CY	$ 550	$ 4,400
Roofing & Misc supports	1	LS	$ 40,000	$ 40,000
			Subtotal =	**$ 78,900**
	Materials/Installation Subtotal =			**$ 689,050**
	15% Construction Contingency Costs=			$ 103,358
	TOTAL CONSTRUCTION COST:			**$ 792,000**
Non -Construction Costs				
Admin/Planning/Design/Environmental Docs (% of construction costs)	15%	LS		$ 118,800
Environmental Mitigation (% of construction costs)	8%	LS		$ 63,360
Right of Way Costs	0.5	AC	$ 30,000	$ 15,000
Construction Administration (% of construction costs)	8%	LS		$ 63,360
Financing Cost				$ 29,700
			Subtotal =	**$ 290,000**
	TOTAL ESTIMATED COST =			**$ 1,082,000**

Annual Costs			
Administration and Insurance ($0.0033/kWh)	690000	$0.0033	$ 2,277
Operation & Maintenance (Labor)			$ 7,058
Repair and Replacement (Parts and Material), (0.3% of total construction cost)		0.30%	$ 2,376
Subtotal			$ 11,711
Contingency (20%)		20%	$ 2,342
Total O&M			$ 14,053





NOTES:

1. MISC ISOLATION VALVES NOT SHOWN

LEGEND

M	MOTORIZED CONTROL VALVE
FM	FLOW METER
F	FIXED SPEED TURBINE (12 CFS)
V	VARIABLE SPEED TURBINE

DIAMOND SPRINGS MAIN PRS 1 (RESERVOIR 8)

HYDROELECTRIC DEVELOPMENT OPTIONS REPORT
HYDRO STATION EQUIPMENT AND TECHNOLOGIES

Typical Project Components

For project construction cost estimating in the screening analysis and more detailed feasibility analyses, typical hydroelectric station layouts were developed for the various types of installations. The types of installations encountered included:

1. larger long term hydro development project (Alder Reservoir),
2. short term "feed in tariff"(FIT) projects at pressure reducing stations,
3. short term "feed in tariff" projects at existing dams,
4. short term "feed in tariff" small pump storage project between storage tanks (Oak Ridge Tanks to Bass Lake Tanks)
5. short and mid term "feed in tariff" projects at the end of raw water supply pipelines,
6. low head canal demonstration project.

For the more detailed feasibility analyses, project facilities were broken down into adequate detail to identify most components required for installations with contingency added for minor variations. The following table shows the basic components included for each of the project types:

Project Type Components

Project Type	Design Parameters	Project Components
Large Long Term (Alder Reservoir)	High Head (over 400ft) Pumped Storage	a. dam & reservoir b. pump station from American River (El. Dorado Canal) to Reservoir c. large diameter penstock (for pumped flow and hydro generation flow) d. high head (Pelton Wheel turbine) hydro-electric station. e. long transmission lines
FIT at Existing Pressure Reducing Stations	Medium head (150 to 350 ft head) Variable flows	a. Tie into existing piping b. discharge to lower pressure pipeline c. Pumps as turbines (PATs) as most economical solution with Francis turbines as an option in complex hydraulic (flow & head variation) applications d. short distance to existing transmission lines

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FIT at Existing Dams	Low to Medium head (75 to 100 ft head) Variable flows	a. Tie into existing piping b. discharge to atmosphere c. Pumps as turbines (PATs) or Cross-flow turbine as most economical solution with Francis turbines as an option. d. short distance to existing transmission lines
FIT pumped storage at Existing Tanks (Oak Ridge Tanks to Bass Lake Tanks)	Constant medium head and constant flow	a. Tie into existing piping b. Separate pumps to storage and single pump as turbines as most economical solution c. Separate pump as turbine is most economical d. short distance to existing transmission lines
FITs at the end of pipelines	Medium to high head (150 to over 600 ft head) Variable flows	a. Tie into existing piping at discharge location b. discharge to canal or reservoir c. Pumps as turbines or Cross-flow turbine as most economical solution for medium head. Pelton Wheel for highest heads d. moderate to long transmission lines
Low head canal demonstration project.	In-canal low head variable flow	a. Specialized technology packaged equipment

Turbine Selection Criteria

For the purpose of the hydroelectric options study, selection of turbines was based primarily on hydraulic head characteristics and to a lesser degree on design flow variability. Other than the Alder Reservoir project all of the projects brought forward for detailed study are relatively low flow (30cfs and under) projects. Once the turbine options were identified, cost of the installation was the final criteria. The following guidelines were used for the selection of turbine units.

Turbine Selection Guidelines

Design Head	**Discharge to atmosphere**	**Discharge to pressurized pipeline**	**Pumped storage**
70 to 350 ft	, Pump as Turbine, Francis, Crossflow	Pump as Turbine or Francis	Pump as Turbine or Francis
Over 350 ft	Pelton Wheel	NA- for these projects	NA-for these projects

As seen in the above table, there is more than one turbine option available for most projects. Final selection of the turbines for use in the study analyses also considered the capital costs and the generating efficiencies of these units.

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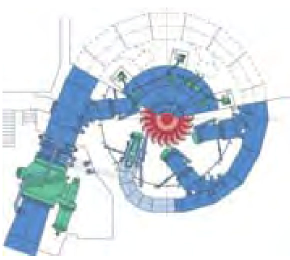
***High Head Applications*:**

Pelton Wheel (or Turgo) turbines were selected for the Alder Reservoir and the Kaiser Siphon projects as both of these projects have over 500 feet of operating head. A single Pelton unit can handle a wide range of flow at relatively high efficiency through velocity control at the nozzle with a needle valve, and or by the use of multiple nozzles. Even at flow as low as 20% of the design rate, the Pelton will perform to near 80% efficiency. These unit can handle heads well beyond the limits of any of the projects analyzed in this study, but are not recommended for heads much below 200ft. Another advantage of these types of units is that bypass can be achieved at the turbine by way of deflectors that can automatically divert the nozzle jet flow away from the wheel.



Multi- nozzle Pelton Wheel Turbine

Pressure Reducing Station (PRS) Sites:

For all of the projects at existing EID pressure reducing stations, pump as turbines (PATs) or reverse pumps were used for the basis of the cost analysis. These units are significantly less expensive than a Francis turbine (which is basically a modified reverse pump) and a Cross-flow turbine which in addition must discharge to atmosphere similar to the Pelton Wheel. The PATs are effective for the mid- head range projects in this study from 70ft to 350ft. Options for PATs become somewhat limited at higher heads.

The disadvantage of the PATs is the need for multiple units when generating over a wide range of flows. PATs are different from a Francis turbine in that they do not have adjustable guide vanes (wicket gates) to regulate flow changes across the impeller (or runner), which allows a single Francis unit to run at highly efficient rate over a wide range of flow. However, even with multiple units, the relatively low cost and availability of the PATs and replacement parts make it an attractive option for these applications. Sizing of the individual units in a multiple unit system must be done carefully, especially if (as in most in-line cases) the head also varies with flow change for the system. For the purpose of this study, multiple PAT applications were sized splitting the system flow up evenly.

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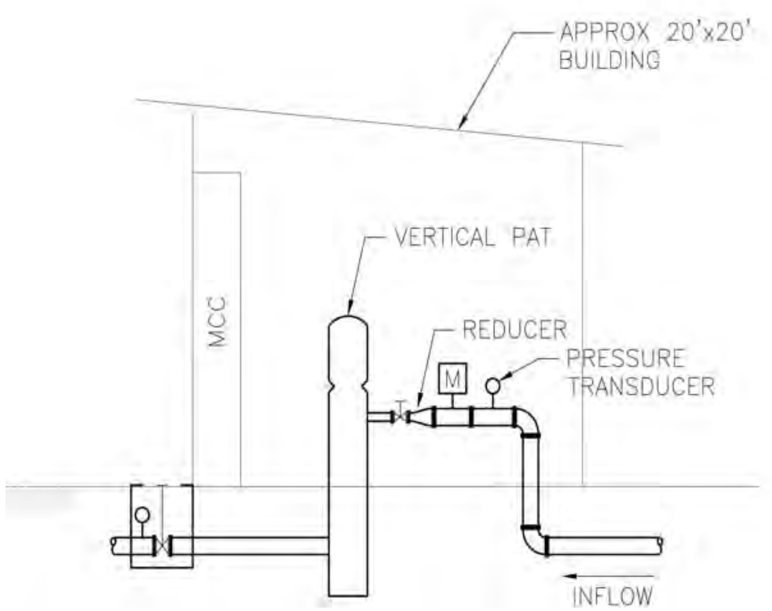

Typical Pump as Turbine (Elevation) NTS

Francis Turbine adjustable wicket gates

Minimum flow

Maximum flow

In addition to the lower cost of PATs, recent application of variable speed regenerative drive technology has increased the capacity to capture variable flow generation using the PATs, where in the past gaps in generation between fix speed units limited the use of PATs under these conditions. The regenerative drive concept is basically providing a variable speed drive (VFD) for a pump application, set in reverse. The regenerative drive unit takes the power generated by the variable flow (speed) reverse pump and converts the power to the proper frequency to interface with the electrical grid. For the purposes of cost estimating and comparison between projects, generation quantities in the hydro options analyses assumed the use of this technology for all PRS sites. During the design phase of selected projects, these advancements using PATs will be compared further against the use of a single Francis unit.

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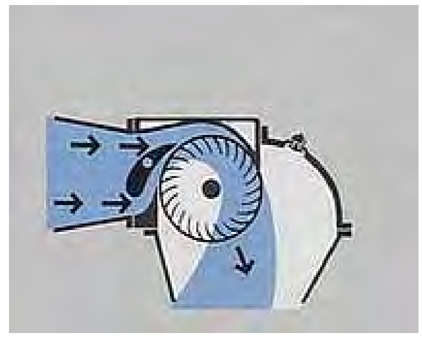
Existing Dam Sites:

For the three potential projects located at existing dams (Sly Park Reservoir, Stumpy Meadows Reservoir and Caples Lake), the same PAT turbine arrangement and technology was applied as for the PRS sites for comparison. Given the project parameters for head, flow and discharge conditions (to atmosphere), Cross-flow (Ossberger) type turbine were also considered for these sites. This type of turbine is an impulse turbine like the Pelton Wheel, but it is not applicable for higher heads. The above projects have relatively low heads between 70ft to 100ft. The Cross-flow does not have nozzled jets directed at a wheel like the Pelton, rather it contains a cylinder drum-like rotor configuration where variable flow is sectioned off in separate cells over portions of the drum to provide high efficiency over a wide range of flows. This turbine is a possible alternative to the PATs, when comparing its higher costs to efficiency. A single Cross-flow unit may also compare well against the costs and efficiency of a Francis unit for these existing dam projects. However, concern for documented mechanical failure at mid to high head applications due to cycle fatigue is a significant draw-back for this turbine selection.



Cross-flow Turbine Section

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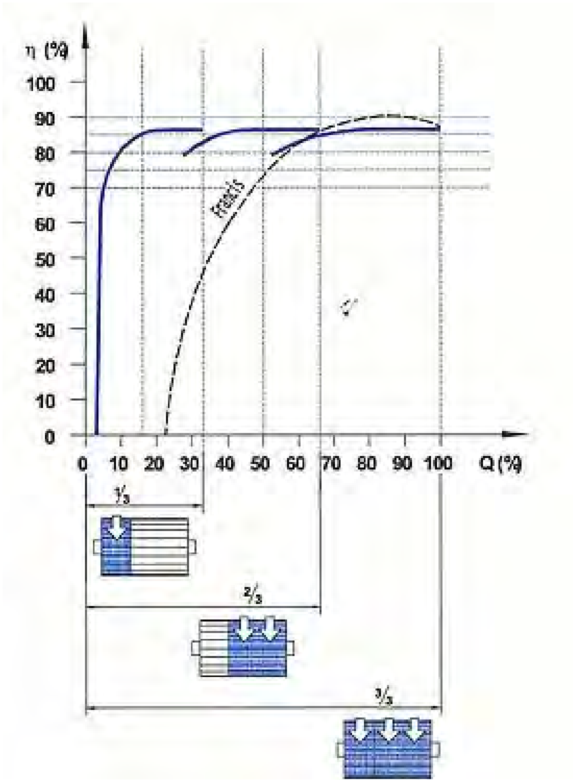

Multi Stage Cross-flow Unit showing efficiency vs Francis unit

Pump Storage Project (Oak Ridge Tanks to Bass Lake Tanks):

For the Oak Ridge Tanks to Bass Lake Tanks project, a single fixed speed PAT generating unit at the Oak Ridge site will be the least expensive and most practical selection. This unit will be separate from the pump station, although with a Francis type turbine, a single unit could both pump the flow to Bass Lake and generate energy in the opposite direction. However, the added cost of the Francis unit does not make this a viable option. The PAT alone cannot provide both functions due to the operating head variation from the pumping mode to the generating mode.

End of Pipeline Applications:

There are three Georgetown Divide PUD projects that are all raw water supply projects at the termination of existing pipeline (or siphons) to either an open canal or reservoir. The Kaiser Siphon (with added pipeline) is a high head application (over 600ft) ideal for a Pelton Wheel turbine. The other two projects (Sandtrap and Buffalo Hill) are mid-head range projects and have been analyzed using the PAT application described previously. As indicated for the dam applications, with mid range head, varied flow and discharge to atmosphere, the Cross-flow turbine should also be considered as an alternative during the design phase of either of these two projects.

Other Design Considerations

The turbine selection is an important component of the hydro station design. However, there are many other design considerations included in the feasibility analyses. Major project components that were included in the project layouts and cost estimate as listed below:

Design Components

Pipe, Valves & Fittings
- Intake and Return Tie into existing Pipe
- In -Line Bypass Valve, piping & vault
- Intake and Return Manifolds
- turbine pipe runs
- motorized control valves
- pressure reducing valve
- check valves
- isolation valves, reducers, misc fittings
- flow meter

Turbine/Generator Units
- Single or Multiple units

Electrical Equipment & Tie-in to Grid
- Electrical Controls/Switchgear for turbine/generator units
- Electrical utility /transformer , misc site electrical
- Hook-up to Grid (power lines, transformers, switches)

Building and Misc Structural
- Masonry building
- Foundation structure (concrete)
- Roofing & Misc supports

Other Misc Items
- Grading, Paving, Drainage and Fencing
- Environmental Mitigation

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Hydrologic, Energy, and Economic/Financial Analyses and Assumptions

Appendix B

Hydrologic, Energy, and Economic/Financial Analyses and Assumptions

Hydrologic and Energy Generation Projections

1.0 Introduction

Reliable hydrologic information and energy generation projection for each hydroelectric option are important in evaluating potential new options as this information is used as the foundation in determining the potential revenue that can be expected at each potential new facility. Section 2 describes the hydroelectric analysis performed as part of the effort to identify hydroelectric opportunities in El Dorado County. Section 3 describes how energy generation projections were developed for each option.

2.0 Hydrologic Analysis

Information representing the flow of water available at each hydroelectric option was collected from purveyors. This information included annual, month, daily and instantaneous flow measurements collected during recent years. This information was used to develop representative information describing flow available for generation at each hydroelectric option under the existing condition. In addition to the existing condition, an evaluation was conducted to investigate the operational benefits to each hydroelectric option of taking advantage of potential additional new water storage capacity that could be added to the conveyance system at key locations to allow efficient timing of flow at each hydroelectric option to take advantage of energy pricing fluctuations throughout the day providing for an increase in project revenue.

2.1 Existing Condition

Flow information representing existing conditions was used to develop the average annual flow and distribution of flow that could be put to use at each hydroelectric option. Flow distribution was evaluated on a monthly and weekly basis as well as the time of day. This detailed level of hydrologic analysis is important to capture the seasonal, daily and time of day flow variations to understand the timing of energy generation as timing is important when estimating revenue of hydroelectric projects.

Flow information available at each hydroelectric option was evaluated based on existing conditions representing the flow available in year 2008. Hydrologic information used to represent water available at each individual hydroelectric option is shown below.

Sly Park Dam - Flow information for 2006, 2007, and 2008 was received from El Dorado Irrigation District (EID) and used to determine annual, seasonal, monthly, and daily flow available to operate the Sly Park hydroelectric option. The following data was used to develop representative information to determine the time-of-day flow distribution.

Summer Weekday -	August 18, 2008 (used to estimate time-of-day for June – September)
Summer Weekend -	August 20, 2008 (used to estimate load shape for June – September)
Fall -	October 1, 2008 (used to estimate load shape for October and November)
Winter -	February 1, 2009 (used to estimate load shape for December – February)
Spring -	May 15, 2008 (used to estimate load shape for March – May)

<u>EDM2 PRS1 -</u> Flow information for 2007 was received from EID and used to determine annual, seasonal, monthly, and daily flow available to operate the EDM2 PRS1 hydroelectric option. The following data was used to develop representative information to determine the time-of-day flow distribution.

Summer Weekday -	September 13, 2008 (used to estimate load shape for June – September)
Summer Weekend -	August 1, 2008 (used to estimate load shape for June – September)
Fall -	October 1, 2008 (used to estimate load shape for October and November)
Winter -	March 1, 2009 (used to estimate load shape for December – February)
Spring -	No information available – no load shaping used for March – May

<u>EDM2 PRS3 -</u> Flow information for 2007 was received from EID and used to determine annual, seasonal, monthly, and daily flow available to operate the EDM2 PRS3 hydroelectric option. The time-of-day flow distribution information developed for EDM2 PRS1 was used for this option.

<u>DSM PRS1 -</u> Flow information for 2007 and 2008 was received from EID and used to determine annual, seasonal, monthly, and daily flow available to operate the DSM PRS1 hydroelectric option. No load shaping was considered as no information was available to determine time-of-day flow distribution for this option.

POM PRS1 @Res B - Flow information for 2007 and 2008 was received from EID and used to determine annual, seasonal, monthly, and daily flow available to operate the POM PRS1 @Res B hydroelectric option. The following data was used to develop representative information to determine the time-of-day flow distribution.

Summer Weekday -	August 13, 2008 (used to estimate load shape for June – September)
Summer Weekend -	August 2, 2008 (used to estimate load shape for June – September)
Fall -	October 1, 2008 (used to estimate load shape for October and November)
Winter -	February 1, 2009 (used to estimate load shape for December – February)
Spring -	May 15, 2008 (used to estimate load shape for March – May)

POM PRS1 Downstream of Res B - Flow information for 2007 and 2008 was received from EID and used to determine annual, seasonal, monthly, and daily flow available to operate the POM PRS1 Downstream of Res B hydroelectric option. The time-of-day flow distribution information developed for POM PRS1 @Res B was used for this option.

POM PRS1 @Res B + POM PRS1 Downstream of Res B – COMBINED - This option is the combination of POM PRS1 @Res B and POM PRS1 Downstream of Res B.

POM PRS5 @Res 7 - Flow information for 2007 and 2008 was received from EID and used to determine annual, seasonal, monthly, and daily flow available to operate the POM PRS5 @Res 7 hydroelectric option. The time-of-day flow distribution information developed for POM PRS1 @Res B was used for this option.

Oak Ridge Tanks to Bass Lake Tanks Pumped Storage - A representative operation of the Gold Hill Intertie to Oak Ridge Tanks Pumped Storage hydroelectric option was developed. The pumping and generation capacity of 10 cfs was used with the following flow operational information.

Pump	11 hours a day during the months of October through May (8 hours during the Night period and 3 hours during the Shoulder-Peak period) 6 hours a day during the months of June through September (6 hours during the Night period)
Generate	11 hours a day during the months of October through May (8 hours during the Super-Peak period and 3 hours during the Shoulder-Peak period) 6 hours a day during the months of June through September (6 hours during the Super-Peak period)

<u>Buffalo Hill Siphon - </u>Representative flow information was received from Georgetown Divide Public Utility District (GDPUD) and used to determine annual, seasonal, monthly, and daily flow available to operate the Buffalo Hill hydroelectric option. No load shaping was considered under existing conditions as flow in the Georgetown Ditch tends to be fairly consistent throughout the day.

<u>Kaiser Siphon - </u>Representative flow information was received from GDPUD and used to determine annual, seasonal, monthly, and daily flow available to operate the Kaiser Siphon hydroelectric option. No load shaping was considered under existing conditions as flow in the Georgetown Ditch tends to be fairly consistent throughout the day.

<u>Sandtrap Siphon - </u>Representative flow information was received from GDPUD and used to determine annual, seasonal, monthly, and daily flow available to operate the Sand Trap Siphon hydroelectric option. No load shaping was considered under existing conditions as flow in the Georgetown Ditch tends to be fairly consistent throughout the day.

2.2 Reoperation

In addition to the existing condition, an evaluation was conducted to investigate the additional project revenue that could be developed at the hydro options along the Georgetown Ditch and Pleasant Oak Main water systems. The simulated reoperation would take advantage of potential additional water storage capacity that could be added to the conveyance system at key locations to allow reoperation of the hydroelectric options to generate more energy during the Super-Peak Period as identified by the State of California Public Utility Commission's Feed-In Tariff program. The Super-Peak period occurs from 12:00 noon – 8:00 pm Monday – Friday (8 hours), except on holidays.

The reoperation scenarios were designed to allow water that under existing conditions passed through the hydroelectric options during Shoulder Peak and Night periods to instead pass through during the Super-Peak period. This doesn't increase the overall generation amount (in fact commonly produces a slight reduction with the preliminary project designs due to reduced turbine efficiencies), but does provide significantly more energy during the Super-Peak period increasing project revenue significantly.

3.0 Energy Generation Projections

Projected energy generation for each hydroelectric option was developed based on time distribution of flow defined by the Super-Peak, Shoulder-Peak and Night periods of the day as used in the State of California Public Utility Commission's Feed-In Tariff program and is shown below.

2008 Market Price Referent
Feed-In Tariff Time of Day Definitions

Period (all year)	Definition
Super Peak	12:00 noon – 8:00 pm Monday – Friday (except holidays)
Shoulder Peak	6:00 am – 12:00 noon, 8:00 pm – 10:00 pm Monday – Friday (except holidays) 6:00 am – 10:00 pm on weekends and holidays
Night	10:00 pm – 6:00 am the following day

Projected energy generation was estimated based on available flow, effective head, efficiency, loss estimates and operation. Energy generation projections were developed for both the existing condition and under the reoperation scenarios.

Generation estimates were developed for year 2008 and escalated by 0.5% per year, where appropriate, to account for future increase in water flow available at certain hydroelectric option sites to reflect an increase in available flow made possible by increasing consumptive demands and water deliveries. Project options are assumed to begin operation during year 2011. Generation was investigated for both 20 and 30 year periods.

The remainder of this appendix contains detailed information on hydrologic flow and energy generation projections for each of the hydrologic options.

Project Option		Period	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Sly Park Dam	2011-30 Generation (mWh)	Super-Peak	13.1	12.7	17.6	20.9	53.7	59.9	32.7	66.7	61.0	67.8	36.9	16.2	460
		Shoulder	29.8	28.8	31.3	37.3	95.7	106.3	58.2	118.5	108.4	97.7	53.2	36.6	800
		Night	23.4	22.6	20.6	24.6	63.1	77.9	42.6	86.8	79.4	66.5	36.2	28.8	570
		TOTAL	*66.3*	*64.1*	*69.5*	*82.8*	*212.4*	*244.1*	*133.5*	*272.0*	*248.8*	*231.9*	*126.3*	*81.5*	*1,830*
	% of generation	Super-Peak	20%	20%	25%	25%	25%	25%	25%	25%	25%	29%	29%	20%	25%
		Shoulder	45%	45%	45%	45%	45%	44%	44%	44%	44%	42%	42%	45%	44%
		Night	35%	35%	30%	30%	30%	32%	32%	32%	32%	29%	29%	35%	31%
		TOTAL	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
El Dorado Main 2 PRS 1 (Tank 3)	2011-30 Generation (mWh)	Super-Peak	24.3	22.0	20.4	37.4	52.6	35.5	36.6	36.6	45.7	40.7	33.1	22.0	410
		Shoulder	43.9	39.7	36.7	67.4	94.8	63.8	66.0	66.0	82.3	77.0	66.4	40.0	740
		Night	34.4	31.0	28.5	52.4	73.7	53.9	54.8	55.6	67.8	56.3	48.3	31.1	590
		TOTAL	*102.6*	*92.7*	*85.6*	*157.2*	*221.1*	*153.1*	*157.4*	*158.2*	*195.9*	*174.0*	*147.8*	*93.1*	*1,740*
	% of generation	Super-Peak	24%	24%	24%	24%	24%	23%	23%	23%	23%	23%	22%	24%	24%
		Shoulder	43%	43%	43%	43%	43%	42%	42%	42%	42%	44%	45%	43%	43%
		Night	33%	33%	33%	33%	33%	35%	35%	35%	35%	32%	33%	33%	34%
		TOTAL	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
El Dorado Main PRS3	2011-30 Generation (mWh)	Super-Peak	6.4	9.9	12.4	20.8	24.9	28.5	27.7	29.4	24.9	13.3	6.5	10.9	220
		Shoulder	10.7	16.6	22.4	37.5	44.8	43.5	38.8	44.9	46.8	37.9	18.7	18.4	380
		Night	8.3	12.9	17.4	29.2	34.8	35.8	39.3	36.9	34.6	18.6	13.6	14.3	300
		TOTAL	*25.4*	*39.4*	*52.3*	*87.5*	*104.4*	*107.7*	*105.7*	*111.3*	*106.2*	*69.8*	*38.7*	*43.6*	*890*
	% of generation	Super-Peak	25%	25%	24%	24%	24%	26%	26%	26%	23%	19%	17%	25%	25%
		Shoulder	42%	42%	43%	43%	43%	40%	37%	40%	44%	54%	48%	42%	43%
		Night	33%	33%	33%	33%	33%	33%	37%	33%	33%	27%	35%	33%	34%
		TOTAL	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*101%*
Diamond Springs Main PRS 1 (Reservoir 8)	2011-30 Generation (mWh)	Super-Peak	9.1	8.2	13.1	11.2	22.5	17.5	16.2	16.2	16.3	11.6	12.7	9.1	160
		Shoulder	16.4	14.8	23.6	20.1	40.6	31.6	29.2	29.2	29.3	20.8	22.8	16.4	290
		Night	12.7	11.5	18.3	15.7	31.6	24.5	22.7	22.7	22.8	16.2	17.7	12.7	230
		TOTAL	*38.2*	*34.5*	*55.0*	*47.0*	*94.7*	*73.6*	*68.1*	*68.1*	*68.4*	*48.6*	*53.2*	*38.2*	*690*
	% of generation	Super-Peak	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	23%
		Shoulder	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	42%
		Night	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%
		TOTAL	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*99%*
POM PRS1 @Res B	2011-30 Generation (mWh)	Super-Peak	9.3	8.4	14.8	22.8	25.5	32.2	29.8	28.9	31.7	20.1	14.5	11.4	250
		Shoulder	16.7	15.1	26.7	41.1	45.9	58.0	53.6	52.0	57.8	36.8	26.0	20.7	450
		Night	13.0	11.8	20.8	32.0	35.7	45.1	41.7	40.5	44.4	28.9	20.3	16.2	350
		TOTAL	*39.1*	*35.3*	*62.3*	*96.0*	*107.1*	*135.4*	*125.1*	*121.4*	*133.9*	*85.8*	*60.8*	*48.3*	*1,050*
	% of generation	Super-Peak	24%	24%	24%	24%	24%	24%	24%	24%	24%	23%	24%	24%	24%
		Shoulder	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%
		Night	33%	33%	33%	33%	33%	33%	33%	33%	33%	34%	33%	33%	33%
		TOTAL	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
POM PRS1 Downstream of Res B	2011-30 Generation (mWh)	Super-Peak	14.0	12.8	21.5	33.8	38.1	49.5	48.7	48.4	48.2	30.1	20.1	16.6	380
		Shoulder	25.2	23.0	38.7	60.9	68.6	89.3	87.7	87.2	87.9	54.1	37.4	29.9	690
		Night	19.6	17.9	30.1	47.3	53.4	69.3	68.1	67.8	67.5	42.4	28.4	23.3	540
		TOTAL	*58.7*	*53.7*	*90.4*	*142.0*	*160.2*	*208.2*	*204.5*	*203.4*	*203.6*	*126.6*	*85.9*	*69.8*	*1,610*
	% of generation	Super-Peak	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	23%	24%	24%
		Shoulder	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%
		Night	33%	33%	33%	33%	33%	33%	33%	33%	33%	34%	33%	33%	34%
		TOTAL	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
Pleasant Oak Main (Reservoir B)	2011-30 Generation (mWh)	Super-Peak	22.8	20.6	33.3	32.9	63.6	71.5	76.7	76.7	61.9	34.0	32.2	22.8	550
		Shoulder	41.0	37.0	60.0	59.3	114.5	131.0	138.1	138.1	111.0	67.4	57.7	41.0	1,000
		Night	31.9	28.8	46.6	46.1	89.1	100.5	107.1	106.3	85.2	57.8	44.1	31.9	780
		TOTAL	*95.6*	*86.3*	*139.9*	*138.3*	*267.2*	*303.0*	*322.0*	*321.1*	*258.1*	*159.3*	*134.1*	*95.6*	*2,320*
	% of generation	Super-Peak	24%	24%	24%	24%	24%	24%	24%	24%	24%	21%	24%	24%	24%
		Shoulder	43%	43%	43%	43%	43%	43%	43%	43%	43%	42%	43%	43%	43%
		Night	33%	33%	33%	33%	33%	33%	33%	33%	33%	36%	33%	33%	34%
		TOTAL	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
Pleasant Oak Main PRS 1 (Reservoir 8)	2011-30 Generation (mWh)	Super-Peak	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
		Shoulder	35.9	32.5	35.9	34.8	35.9	0.0	0.0	0.0	0.0	35.9	34.8	35.9	280
		Night	95.8	86.5	95.8	92.7	95.8	52.7	54.4	54.4	52.7	95.8	92.7	95.8	970
		TOTAL	*131.7*	*119.0*	*131.7*	*127.5*	*131.7*	*52.7*	*54.4*	*54.4*	*52.7*	*131.7*	*127.5*	*131.7*	*1,247*
	% of generation	Super-Peak	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Shoulder	27%	27%	27%	27%	27%	0%	0%	0%	0%	27%	27%	27%	22%
		Night	73%	73%	73%	73%	73%	100%	100%	100%	100%	73%	73%	73%	78%
		TOTAL	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
Oak Ridge Tanks to Bass Lake Tanks Pumped Storage	2011-30 Pumping (mWh)	Super-Peak	48.0	43.3	48.0	46.4	48.0	26.4	27.3	27.3	26.4	48.0	46.4	48.0	480
		Shoulder	44.4	40.1	44.4	42.9	44.4	10.6	10.9	10.9	10.6	44.4	42.9	44.4	390
		Night	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
		TOTAL	*92.3*	*83.4*	*92.3*	*89.3*	*92.3*	*37.0*	*38.2*	*38.2*	*37.0*	*92.3*	*89.3*	*92.3*	*870*
	% of generation	Super-Peak	52%	52%	52%	52%	52%	71%	71%	71%	71%	52%	52%	52%	55%
		Shoulder	48%	48%	48%	48%	48%	29%	29%	29%	29%	48%	48%	48%	45%
		Night	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		TOTAL	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
	2011-30 Generation (mWh)	Super-Peak	8.9	8.0	8.9	8.6	28.9	27.9	28.9	28.9	27.9	8.9	8.6	8.9	200
		Shoulder	16.0	14.4	16.0	15.4	52.0	50.3	52.0	52.0	50.3	16.0	15.4	16.0	370
		Night	12.4	11.2	12.4	12.0	40.4	39.1	40.4	40.4	39.1	12.4	12.0	12.4	280
		TOTAL	*37.2*	*33.6*	*37.2*	*36.0*	*121.2*	*117.3*	*121.2*	*121.2*	*117.3*	*37.2*	*36.0*	*37.2*	*850*
	% of generation	Super-Peak	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
		Shoulder	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	44%
		Night	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%
		TOTAL	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
Kaiser Siphon	2011-30 Generation (mWh)	Super-Peak	46.7	42.1	46.7	45.1	110.9	107.3	110.9	110.9	107.3	46.7	45.1	46.7	870
		Shoulder	84.0	75.8	84.0	81.3	199.6	193.1	199.6	199.6	193.1	84.0	81.3	84.0	1,560
		Night	65.3	59.0	65.3	63.2	155.2	150.2	155.2	155.2	150.2	65.3	63.2	65.3	1,210
		TOTAL	*195.9*	*177.0*	*195.9*	*189.6*	*465.6*	*450.6*	*465.6*	*465.6*	*450.6*	*195.9*	*189.6*	*195.9*	*3,640*
	% of generation	Super-Peak	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
		Shoulder	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%
		Night	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%
		TOTAL	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
Buffalo Hill Siphon	2011-30 Generation (mWh)	Super-Peak	11.6	10.5	11.6	11.3	29.7	28.7	29.7	29.7	28.7	11.6	11.3	11.6	230
		Shoulder	20.9	18.9	20.9	20.3	53.4	51.7	53.4	53.4	51.7	20.9	20.3	20.9	410
		Night	16.3	14.7	16.3	15.8	41.6	40.2	41.6	41.6	40.2	16.3	15.8	16.3	320
		TOTAL	*48.8*	*44.1*	*48.8*	*47.3*	*124.7*	*120.6*	*124.7*	*124.7*	*120.6*	*48.8*	*47.3*	*48.8*	*950*
	% of generation	Super-Peak	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
		Shoulder	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%
		Night	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	34%
		TOTAL	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*101%*
Sand Trap Siphon	2011-30 Generation (mWh)	Super-Peak	10.7	9.7	10.7	10.4	39.8	38.5	39.8	39.8	38.5	10.7	10.4	10.7	270
		Shoulder	19.3	17.5	19.3	18.7	71.7	69.3	71.7	71.7	69.3	19.3	18.7	19.3	490
		Night	15.0	13.6	15.0	14.6	55.7	53.9	55.7	55.7	53.9	15.0	14.6	15.0	380
		TOTAL	*45.1*	*40.8*	*45.1*	*43.7*	*167.2*	*161.8*	*167.2*	*167.2*	*161.8*	*45.1*	*43.7*	*45.1*	*1,130*
	% of generation	Super-Peak	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
		Shoulder	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%
		Night	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	34%
		TOTAL	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*101%*

B2.1 El Dorado Main 2 PRS 1 (Tank 3)

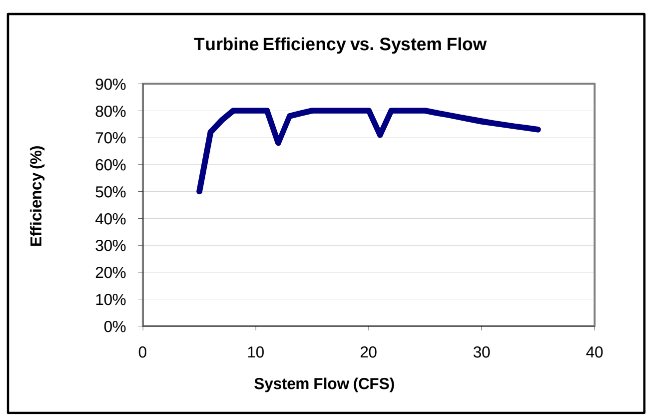
	Total	*Super Peak*							*Shoulder Peak*													
		Weekday							*Weekday*							*Weekend*						
	System Flow (cfs)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)
Jan	10	10.8	160	9	130	218	80%	22.8	10.1	150	9	130	218	80%	22.8	10.1	120	9	110	220	80%	18.4
Feb	10	10.8	140	9	120	218	80%	20.6	10.1	130	9	120	218	80%	20.6	10.1	110	9	100	220	80%	16.7
Mar	12	12.0	180	9	130	215	68%	19.1	12.0	180	9	130	215	68%	19.1	12.0	140	9	110	215	68%	15.3
Apr	15	15.0	210	15	210	208	80%	35.1	15.0	210	15	210	208	80%	35.1	15.0	170	15	170	208	80%	28.1
May	24	24.0	350	24	350	177	80%	49.4	24.0	350	24	350	177	80%	49.4	24.0	280	24	280	177	80%	39.6
Jun	37	35.5	500	24	340	135	73%	33.3	41.8	590	24	340	135	73%	33.3	37.0	420	24	270	135	73%	26.6
Jul	38	36.5	530	24	350	135	73%	34.4	42.9	630	24	350	135	73%	34.4	38.0	450	24	280	135	73%	27.5
Aug	37	35.5	520	24	350	135	73%	34.4	41.8	610	24	350	135	73%	34.4	37.0	430	24	280	135	73%	27.5
Sep	27	25.9	370	24	340	163	78%	43.0	30.5	430	24	340	163	78%	43.0	27.0	310	24	270	163	78%	34.4
Oct	16	15.2	220	16	230	205	80%	38.2	17.0	250	17	250	203	80%	40.2	17.0	200	17.0	200	203	80%	32.1
Nov	14	13.3	190	13.3	190	213	78%	31.1	14.8	210	14.8	210	210	79%	34.7	14.8	170	14.8	170	210	79%	27.7
Dec	8	8.6	130	8	120	222	80%	20.7	8.1	120	8.1	120	222	80%	20.9	8.1	90	8.1	90	222	80%	16.7
Total =	21	20.3	3,500	17	2,860	-	-	**380.0**	22.3	3,860	17	2,900	-	-	**390.0**	20.8	2,890	17	2,330	-	-	**310.0**

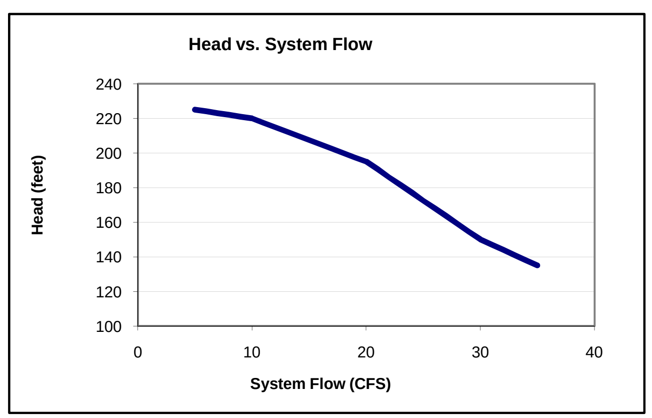
	Total	*Night*																
		Weekday							*Weekend*									
	System Flow (cfs)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	2011-30 Generation* (mWh)	2011-40 Generation* (mWh)	2008 Generation* (mWh)
Jan	10	10.1	150	9	130	220	80%	23.0	10.1	60	9	50	220	80%	9.2	102.6	105	96.4
Feb	10	10.1	130	9	120	220	80%	20.8	10.1	50	9	50	220	80%	8.3	92.7	95	87
Mar	12	12.0	180	9	130	215	68%	19.1	12.0	70	9	50	215	68%	7.7	85.6	88	80
Apr	15	15.0	210	15	210	208	80%	35.1	15.0	90	15	90	208	80%	14.1	157.2	161	148
May	24	24.0	350	24	350	177	80%	49.4	24.0	140	24	140	177	80%	19.8	221.1	227	208
Jun	37	31.1	440	24	340	147	75%	37.3	37.0	210	24	140	135	73%	13.3	153.1	157	144
Jul	38	31.9	470	24	350	144	75%	37.7	38.0	220	24	140	135	73%	13.8	157.4	161	148
Aug	37	31.1	460	24	350	147	75%	38.5	37.0	220	24	140	135	73%	13.8	158.2	162	149
Sep	27	22.7	320	22.7	320	182	80%	46.5	27.0	150	24.0	140	163	78%	17.2	195.9	201	184
Oct	16	15.8	230	15.8	230	205	80%	37.8	15.8	90	15.8	90	205	80%	15.1	174.0	178	163
Nov	14	13.9	200	13.9	200	210	79%	32.4	13.9	80	13.9	80	210	79%	13.0	147.8	152	139
Dec	8	8.1	120	8.1	120	222	80%	20.9	8.1	50	8.1	50	222	80%	8.4	93.1	96	87
Total =	21	18.8	3,260	17	2,850	-	-	**400.0**	20.7	1,430	17	1,160	-	-	**150.0**	**1,740**	**1,780**	**1,630**

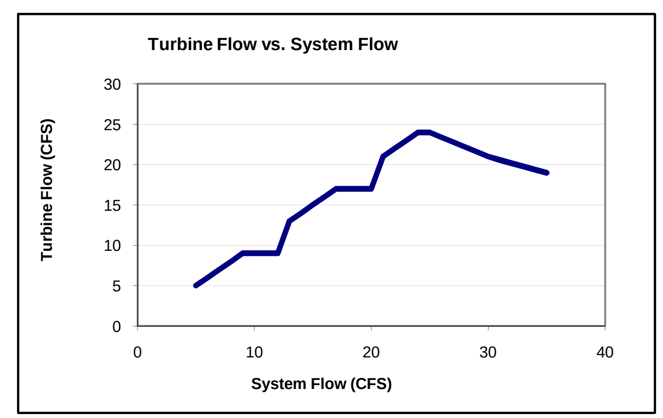
* Assumed at 97% of flow available for generation.

Efficiency

System Flow (cfs)	Turbine Flow (cfs)	Head (ft)	Eff (%)
5	5	225	50%
6	6	224	72%
7	7	223	77%
8	8	222	80%
9	9	221	80%
10	9	220	80%
11	9	218	80%
12	9	215	68%
13	13	213	78%
14	14	210	79%
15	15	208	80%
16	16	205	80%
17	17	203	80%
18	17	200	80%
19	17	198	80%
20	17	195	80%
21	21	191	71%
22	22	186	80%
23	23	182	80%
24	24	177	80%
25	24	173	80%
26	23	168	79%
27	23	163	78%
28	22	159	78%
29	22	154	77%
30	21	150	76%
31	21	147	75%
32	20	144	75%
33	20	141	74%
34	19	138	74%
35	19	135	73%







B2.1 El Dorado Main 2 PRS 1 (Tank 3)

Capital Cost	$ 1,556,000	360	Plant Size (kW)	11.46%	IRR
First Year Annual O&M Costs	$ 7,058	1,739	Avg. Annual Gen (MWh)	$ 777,089	NPV
First Year Annual A&I Costs	$ 5,610	$ 117.30	Baseline Market Price Referent ($/MWh)	14	Payback Period (Years)
First Year Annual Repair & Replace Costs	$ 3,399	2011	Initial Year of Operation	55%	Capacity Factor
First Year Annual Contingency Costs	$ 3,213	30	Term of Debt (Years)	1.53	Minimum Annual Debt Service Coverage
Annual Costs Inflation Rate	2.50%	20	Length of Initial Contract (Years)	$ 118.46	Average Price Received ($/MWh)
Cost of Debt	6.00%	50	Project Physical Life (Years)	$ 895	Capital Cost per Avg Annual Generation ($/MWh)
Discount Rate	6.00%	1.50%	Finance Fee		

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Sales										
Generating Capacity (MW)	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
Energy (MWH)	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739
Energy Price ($/MWH)	$ 118.46	$ 118.46	$ 118.46	$ 118.46	$ 118.46	$ 118.46	$ 118.46	$ 118.46	$ 118.46	$ 118.46
Energy Sales Revenue ($)	$ 205,976	$ 205,976	$ 205,976	$ 205,976	$ 205,976	$ 205,976	$ 205,976	$ 205,976	$ 205,976	$ 205,976
Cost of Operations										
Operations & Maintenance	$ (7,058)	$ (7,234)	$ (7,415)	$ (7,601)	$ (7,791)	$ (7,985)	$ (8,185)	$ (8,390)	$ (8,599)	$ (8,814)
Administration & Insurance	$ (5,610)	$ (5,750)	$ (5,894)	$ (6,041)	$ (6,192)	$ (6,347)	$ (6,506)	$ (6,669)	$ (6,835)	$ (7,006)
Repair and Replacement	$ (3,399)	$ (3,484)	$ (3,571)	$ (3,660)	$ (3,752)	$ (3,846)	$ (3,942)	$ (4,040)	$ (4,141)	$ (4,245)
Contingency	$ (3,213)	$ (3,293)	$ (3,376)	$ (3,460)	$ (3,547)	$ (3,635)	$ (3,726)	$ (3,819)	$ (3,915)	$ (4,013)
Total Cost of Operations ($)	$ (19,280)	$ (19,762)	$ (20,256)	$ (20,762)	$ (21,282)	$ (21,814)	$ (22,359)	$ (22,918)	$ (23,491)	$ (24,078)
Operating Income	$ 186,696	$ 186,214	$ 185,720	$ 185,213	$ 184,694	$ 184,162	$ 183,617	$ 183,058	$ 182,485	$ 181,898
Debt Service										
Principal	$ (19,977)	$ (21,176)	$ (22,446)	$ (23,793)	$ (25,220)	$ (26,734)	$ (28,338)	$ (30,038)	$ (31,840)	$ (33,751)
Interest	$ (94,760)	$ (93,562)	$ (92,291)	$ (90,944)	$ (89,517)	$ (88,004)	$ (86,400)	$ (84,699)	$ (82,897)	$ (80,987)
Total Debt Service ($)	$ (114,737)	$ (114,737)	$ (114,737)	$ (114,737)	$ (114,737)	$ (114,737)	$ (114,737)	$ (114,737)	$ (114,737)	$ (114,737)
Project Revenues	$ 71,958	$ 71,476	$ 70,982	$ 70,476	$ 69,957	$ 69,425	$ 68,880	$ 68,321	$ 67,748	$ 67,160
Cash Flow for IRR Calculation	$ (1,392,644)	$ 186,214	$ 185,720	$ 185,213	$ 184,694	$ 184,162	$ 183,617	$ 183,058	$ 182,485	$ 181,898
Cumulative Repayment	$ (1,300,709)	$ (1,208,057)	$ (1,114,628)	$ (1,020,360)	$ (925,182)	$ (829,024)	$ (731,807)	$ (633,448)	$ (533,860)	$ (432,949)
Present Value of Cash Flow	$ 71,958	$ 67,431	$ 63,174	$ 59,173	$ 55,412	$ 51,878	$ 48,557	$ 45,437	$ 42,506	$ 39,752
Debt Service Coverage	1.63	1.62	1.62	1.61	1.61	1.61	1.60	1.60	1.59	1.59
Payback period										

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sales										
Generating Capacity (MW)	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
Energy (MWH)	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739	1,739
Energy Price ($/MWH)	$ 118.46	$ 118.46	$ 118.46	$ 118.46	$ 118.46	$ 118.46	$ 118.46	$ 118.46	$ 118.46	118.46
Energy Sales Revenue ($)	$ 205,976	$ 205,976	$ 205,976	$ 205,976	$ 205,976	$ 205,976	$ 205,976	$ 205,976	$ 205,976	205,976
Cost of Operations										
Operations & Maintenance	$ (9,035)	$ (9,261)	$ (9,492)	$ (9,730)	$ (9,973)	$ (10,222)	$ (10,478)	$ (10,740)	$ (11,008)	(11,283)
Administration & Insurance	$ (7,181)	$ (7,361)	$ (7,545)	$ (7,733)	$ (7,927)	$ (8,125)	$ (8,328)	$ (8,536)	$ (8,750)	(8,968)
Repair and Replacement	$ (4,351)	$ (4,460)	$ (4,571)	$ (4,686)	$ (4,803)	$ (4,923)	$ (5,046)	$ (5,172)	$ (5,301)	(5,434)
Contingency	$ (4,113)	$ (4,216)	$ (4,321)	$ (4,429)	$ (4,540)	$ (4,653)	$ (4,770)	$ (4,889)	$ (5,011)	(5,136)
Total Cost of Operations ($)	$ (24,680)	$ (25,297)	$ (25,929)	$ (26,578)	$ (27,242)	$ (27,923)	$ (28,621)	$ (29,337)	$ (30,070)	(30,822)
Operating Income	$ 181,296	$ 180,679	$ 180,046	$ 179,398	$ 178,734	$ 178,053	$ 177,354	$ 176,639	$ 175,906	175,154
Debt Service										
Principal	$ (35,776)	$ (37,922)	$ (40,198)	$ (42,609)	$ (45,166)	$ (47,876)	$ (50,748)	$ (53,793)	$ (57,021)	(60,442)
Interest	$ (78,962)	$ (76,815)	$ (74,540)	$ (72,128)	$ (69,571)	$ (66,861)	$ (63,989)	$ (60,944)	$ (57,716)	(54,295)
Total Debt Service ($)	$ (114,737)	$ (114,737)	$ (114,737)	$ (114,737)	$ (114,737)	$ (114,737)	$ (114,737)	$ (114,737)	$ (114,737)	(114,737)
Project Revenues	$ 66,558	$ 65,941	$ 65,309	$ 64,661	$ 63,996	$ 63,315	$ 62,617	$ 61,902	$ 61,168	60,416
Cash Flow for IRR Calculation	$ 181,296	$ 180,679	$ 180,046	$ 179,398	$ 178,734	$ 178,053	$ 177,354	$ 176,639	$ 175,906	175,154
Cumulative Repayment	$ (330,615)	$ (226,752)	$ (121,245)	$ (13,975)	$ 95,187	$ 206,378	$ 319,744	$ 435,439	$ 553,628	674,487
Present Value of Cash Flow	$ 37,166	$ 34,737	$ 32,457	$ 30,315	$ 28,306	$ 26,419	$ 24,649	$ 22,988	$ 21,430	19,968
Debt Service Coverage	1.58	1.57	1.57	1.56	1.56	1.55	1.55	1.54	1.53	1.53
Payback period					14	15	16	17	18	19

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
TOD Factors													
Super-Peak	1.090	1.090	1.130	1.130	1.130	2.010	2.010	2.010	2.010	1.090	1.090	1.090	
Shoulder	0.960	0.960	0.860	0.860	0.860	1.140	1.140	1.140	1.140	0.960	0.960	0.960	
Night	0.780	0.780	0.630	0.630	0.630	0.720	0.720	0.720	0.720	0.780	0.780	0.780	
TOD Prices													
Super-Peak	$ 127.86	$ 127.86	$ 132.55	$ 132.55	$ 132.55	$ 235.77	$ 235.77	$ 235.77	$ 235.77	$ 127.86	$ 127.86	$ 127.86	$ 1,980.02
Shoulder	$ 112.61	$ 112.61	$ 100.88	$ 100.88	$ 100.88	$ 133.72	$ 133.72	$ 133.72	$ 133.72	$ 112.61	$ 112.61	$ 112.61	$ 1,400.56
Night	$ 91.49	$ 91.49	$ 73.90	$ 73.90	$ 73.90	$ 84.46	$ 84.46	$ 84.46	$ 84.46	$ 91.49	$ 91.49	$ 91.49	$ 1,016.99
TOD Generation													
Super-Peak	24.3	22.0	20.4	37.4	52.6	35.5	36.6	36.6	45.7	40.7	33.1	22.0	407.0
Shoulder	43.9	39.7	36.7	67.4	94.8	63.8	66.0	66.0	82.3	77.0	66.4	40.0	744.0
Night	34.4	31.0	28.5	52.4	73.7	53.9	54.8	55.6	67.8	56.3	48.3	31.1	587.9
TOTAL	102.6	92.7	85.6	157.2	221.1	153.1	157.4	158.2	195.9	174.0	147.8	93.1	1,738.8
Revenue													
Super-Peak	$ 3,109	$ 2,808	$ 2,702	$ 4,960	$ 6,978	$ 8,360	$ 8,639	$ 8,639	$ 10,786	$ 5,197	$ 4,236	$ 2,814	$ 69,228
Shoulder	$ 4,949	$ 4,470	$ 3,701	$ 6,795	$ 9,560	$ 8,535	$ 8,820	$ 8,820	$ 11,011	$ 8,669	$ 7,481	$ 4,506	$ 87,316
Night	$ 3,143	$ 2,839	$ 2,109	$ 3,871	$ 5,447	$ 4,548	$ 4,629	$ 4,700	$ 5,727	$ 5,155	$ 4,416	$ 2,848	$ 49,431
TOTAL	$ 11,201	$ 10,117	$ 8,512	$ 15,626	$ 21,985	$ 21,443	$ 22,088	$ 22,158	$ 27,523	$ 19,022	$ 16,133	$ 10,168	$ 205,976
Weighted Average Price	$ 109.15	$ 109.15	$ 99.43	$ 99.43	$ 99.43	$ 140.03	$ 140.32	$ 140.03	$ 140.50	$ 109.33	$ 109.13	$ 109.16	$ 118.46

Source: PG&E Advice Letter 3410-E. January 27, 2009

	Length of Contract		
Start Year	10	15	20
2010	$ 101.75	$ 107.48	$ 113.90
2011	$ 104.00	$ 110.46	$ 117.30
2012	$ 106.98	$ 114.05	$ 121.26
2013	$ 109.98	$ 117.76	$ 125.27
2014	$ 112.78	$ 121.22	$ 128.97
2015	$ 116.05	$ 125.03	$ 132.90
2016	$ 119.71	$ 129.15	$ 137.06
2017	$ 123.67	$ 133.52	$ 141.44
2018	$ 128.02	$ 138.14	$ 146.03
2019	$ 132.71	$ 142.98	$ 150.80
2020	$ 137.76	$ 147.97	$ 155.78

Source: PG&E Advice Letter 3410-E. January 27, 2009

B2.2 El Dorado Main 2 PRS 3

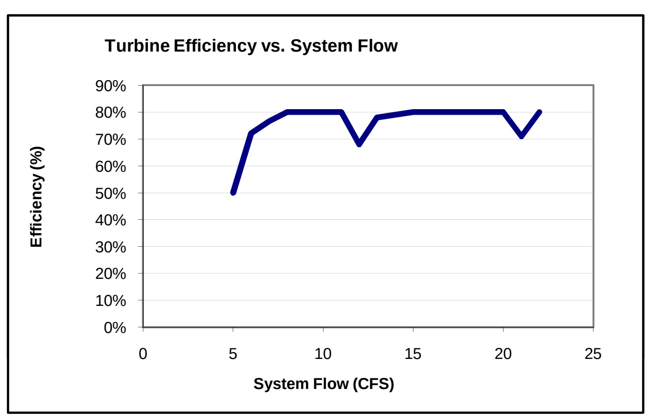
	Total	*Super Peak*							*Shoulder Peak*													
		Weekday							*Weekday*							*Weekend*						
	System Flow (cfs)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)
Jan	5	5.4	80	5.4	80	152	50%	6.0	5.1	70	5.1	70	152	50%	5.6	5.1	60	5.1	60	152	50%	4.5
Feb	6	6.5	90	6.5	90	151	72%	9.3	6.1	80	6.1	80	151	72%	8.7	6.1	60	6.1	60	151	72%	6.9
Mar	7	7.0	100	7.0	100	149	77%	11.7	7.0	100	7.0	100	149	77%	11.7	7.0	80	7.0	80	149	77%	9.3
Apr	13	13.0	180	13.0	180	137	78%	19.6	13.0	180	13.0	180	137	78%	19.6	13.0	150	13.0	150	137	78%	15.6
May	19	19.0	280	17	250	118	80%	23.3	19.0	280	17	250	118	80%	23.3	19.0	220	17	200	118	80%	18.7
Jun	25	24.0	340	24	340	99	80%	26.8	28.3	400	22	310	84	78%	20.3	25.0	280	24	270	95	80%	20.5
Jul	27	25.9	380	23.5	340	95	80%	26.0	30.5	450	21	310	73	76%	17.0	27.0	320	23	270	92	79%	19.5
Aug	25	24.0	350	24	350	99	80%	27.7	28.3	410	22	320	84	78%	21.0	25.0	290	24	280	95	80%	21.2
Sep	19	18.2	260	17	240	122	80%	23.4	21.5	300	21.5	300	107	80%	25.9	19.0	220	17	190	118	80%	18.1
Oct	12	11.4	170	9	130	140	68%	12.5	12.7	190	12.7	190	137	78%	19.8	12.7	150	12.7	150	137	78%	15.8
Nov	6	5.7	80	5.7	80	152	50%	6.1	6.4	90	6.4	90	151	72%	9.7	6.4	70	6.4	70	151	72%	7.8
Dec	6	6.5	90	6.5	90	151	72%	10.3	6.1	90	6.1	90	151	72%	9.6	6.1	70	6.1	70	151	72%	7.7
Total =	14	13.9	2,400	13	2,270	-	-	**200.0**	15.3	2,640	13	2,290	-	-	**190.0**	14.3	1,970	13	1,850	-	-	**170.0**

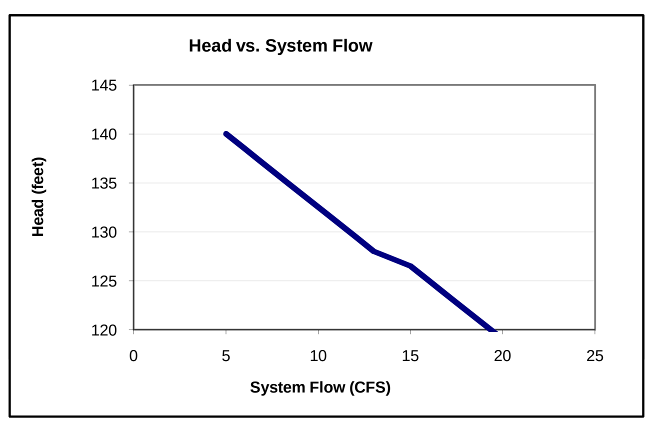
	Total	*Night*																
		Weekday							*Weekend*									
	System Flow (cfs)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	2011-30 Generation* (mWh)	2011-40 Generation* (mWh)	2008 Generation* (mWh)
Jan	5	5.1	70	5.1	70	152	50%	5.6	5.1	30	5.1	30	152	50%	2.2	25	26	24
Feb	6	6.1	80	6.1	80	151	72%	8.7	6.1	30	6.1	30	151	72%	3.5	39	40	37
Mar	7	7.0	100	7.0	100	149	77%	11.7	7.0	40	7.0	40	149	77%	4.7	52	54	49
Apr	13	13.0	180	13.0	180	137	78%	19.6	13.0	70	13.0	70	137	78%	7.8	87	90	82
May	19	19.0	280	17	250	118	80%	23.3	19.0	110	17	100	118	80%	9.3	104	107	98
Jun	25	21.0	300	21	300	111	71%	23.3	25.0	140	24	140	95	80%	10.3	108	111	101
Jul	27	22.7	330	22.7	330	103	80%	27.2	27.0	160	23	130	92	79%	9.7	106	108	99
Aug	25	21.0	310	21	310	111	71%	24.1	25.0	150	24	140	95	80%	10.6	111	114	105
Sep	19	16.0	230	16.0	230	130	80%	23.4	19.0	110	17.0	100	118	80%	9.0	106	109	100
Oct	12	11.9	170	9.0	130	140	68%	12.5	11.9	70	9.0	50	140	68%	5.0	70	72	66
Nov	6	5.9	80	5.9	80	151	72%	9.1	5.9	30	5.9	30	151	72%	3.6	39	40	36
Dec	6	6.1	90	6.1	90	151	72%	9.6	6.1	40	6.1	40	151	72%	3.8	44	45	41
Total =	14	12.9	2,220	12	2,150	-	-	**200.0**	14.2	980	13	900	-	-	**80.0**	**890**	**910**	**840**

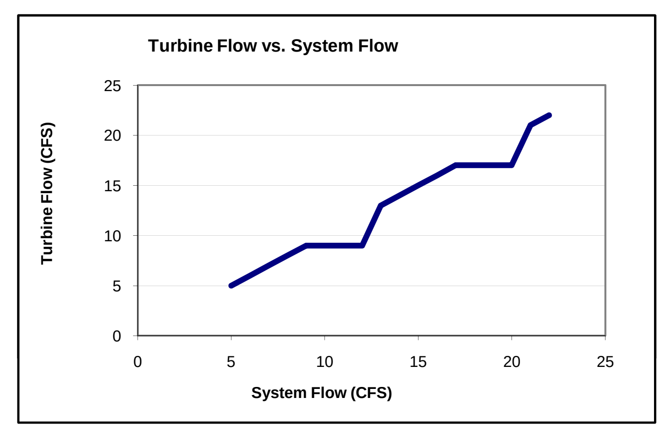
* Assumed at 97% of flow available for generation.

Efficiency

System Flow (cfs)	Turbine Flow (cfs)	Head (ft)	Eff (%)
5	5	152	50%
6	6	151	72%
7	7	149	77%
8	8	148	80%
9	9	146	80%
10	9	145	80%
11	9	142	80%
12	9	140	68%
13	13	137	78%
15	15	134	80%
16	16	130	80%
17	17	126	80%
18	17	122	80%
19	17	118	80%
20	17	115	80%
21	21	111	71%
22	22	107	80%
23	23	103	80%
24	24	99	80%
25	24	95	80%
30	21	73	76%







B2.2 El Dorado Main 2 PRS 3

Capital Cost	$ 1,409,000	195	Plant Size (kW)	2.57%	IRR
First Year Annual O&M Costs	$ 7,058	892	Avg. Annual Gen (MWh)	$ (152,982)	NPV
First Year Annual A&I Costs	$ 2,937	$ 117.30	Baseline Market Price Referent ($/MWh)	>20	Payback Period (Years)
First Year Annual Repair & Replace Costs	$ 3,075	2011	Initial Year of Operation	52%	Capacity Factor
First Year Annual Contingency Costs	$ 2,614	30	Term of Debt (Years)	0.81	Minimum Annual Debt Service Coverage
Annual Costs Inflation Rate	2.50%	20	Length of Initial Contract (Years)	$ 122.95	Average Price Received ($/MWh)
Cost of Debt	6.00%	50	Project Physical Life (Years)	$ 1,580	Capital Cost per Avg Annual Generation ($/MWh)
Discount Rate	6.00%	1.50%	Finance Fee		

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Sales										
Generating Capacity (MW)	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Energy (MWH)	892	892	892	892	892	892	892	892	892	892
Energy Price ($/MWH)	$ 122.95	$ 122.95	$ 122.95	$ 122.95	$ 122.95	$ 122.95	$ 122.95	$ 122.95	$ 122.95	$ 122.95
Energy Sales Revenue ($)	$ 109,667	$ 109,667	$ 109,667	$ 109,667	$ 109,667	$ 109,667	$ 109,667	$ 109,667	$ 109,667	$ 109,667
Cost of Operations										
Operations & Maintenance	$ (7,058)	$ (7,234)	$ (7,415)	$ (7,601)	$ (7,791)	$ (7,985)	$ (8,185)	$ (8,390)	$ (8,599)	$ (8,814)
Administration & Insurance	$ (2,937)	$ (3,010)	$ (3,086)	$ (3,163)	$ (3,242)	$ (3,323)	$ (3,406)	$ (3,491)	$ (3,578)	$ (3,668)
Repair and Replacement	$ (3,075)	$ (3,152)	$ (3,231)	$ (3,311)	$ (3,394)	$ (3,479)	$ (3,566)	$ (3,655)	$ (3,747)	$ (3,840)
Contingency	$ (2,614)	$ (2,679)	$ (2,746)	$ (2,815)	$ (2,885)	$ (2,958)	$ (3,031)	$ (3,107)	$ (3,185)	$ (3,265)
Total Cost of Operations ($)	$ (15,684)	$ (16,076)	$ (16,478)	$ (16,890)	$ (17,312)	$ (17,745)	$ (18,189)	$ (18,643)	$ (19,109)	$ (19,587)
Operating Income	$ 93,983	$ 93,591	$ 93,189	$ 92,777	$ 92,355	$ 91,922	$ 91,479	$ 91,024	$ 90,558	$ 90,080
Debt Service										
Principal	$ (18,090)	$ (19,175)	$ (20,326)	$ (21,545)	$ (22,838)	$ (24,208)	$ (25,661)	$ (27,200)	$ (28,832)	$ (30,562)
Interest	$ (85,808)	$ (84,723)	$ (83,572)	$ (82,353)	$ (81,060)	$ (79,690)	$ (78,237)	$ (76,698)	$ (75,066)	$ (73,336)
Total Debt Service ($)	$ (103,898)	$ (103,898)	$ (103,898)	$ (103,898)	$ (103,898)	$ (103,898)	$ (103,898)	$ (103,898)	$ (103,898)	$ (103,898)
Project Revenues	$ (9,914)	$ (10,306)	$ (10,708)	$ (11,120)	$ (11,543)	$ (11,975)	$ (12,419)	$ (12,874)	$ (13,340)	$ (13,817)
Cash Flow for IRR Calculation	$ (1,336,152)	$ 93,591	$ 93,189	$ 92,777	$ 92,355	$ 91,922	$ 91,479	$ 91,024	$ 90,558	$ 90,080
Cumulative Repayment	$ (1,327,976)	$ (1,319,108)	$ (1,309,490)	$ (1,299,066)	$ (1,287,770)	$ (1,275,538)	$ (1,262,296)	$ (1,247,970)	$ (1,232,477)	$ (1,215,733)
Present Value of Cash Flow	$ (9,914)	$ (9,723)	$ (9,530)	$ (9,337)	$ (9,143)	$ (8,949)	$ (8,755)	$ (8,562)	$ (8,370)	$ (8,179)
Debt Service Coverage	0.90	0.90	0.90	0.89	0.89	0.88	0.88	0.88	0.87	0.87
Payback period										

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sales										
Generating Capacity (MW)	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Energy (MWH)	892	892	892	892	892	892	892	892	892	892
Energy Price ($/MWH)	$ 122.95	$ 122.95	$ 122.95	$ 122.95	$ 122.95	$ 122.95	$ 122.95	$ 122.95	$ 122.95	$ 122.95
Energy Sales Revenue ($)	$ 109,667	$ 109,667	$ 109,667	$ 109,667	$ 109,667	$ 109,667	$ 109,667	$ 109,667	$ 109,667	$ 109,667
Cost of Operations										
Operations & Maintenance	$ (9,035)	$ (9,261)	$ (9,492)	$ (9,730)	$ (9,973)	$ (10,222)	$ (10,478)	$ (10,740)	$ (11,008)	$ (11,283)
Administration & Insurance	$ (3,760)	$ (3,854)	$ (3,950)	$ (4,049)	$ (4,150)	$ (4,254)	$ (4,360)	$ (4,469)	$ (4,581)	$ (4,695)
Repair and Replacement	$ (3,936)	$ (4,035)	$ (4,136)	$ (4,239)	$ (4,345)	$ (4,454)	$ (4,565)	$ (4,679)	$ (4,796)	$ (4,916)
Contingency	$ (3,346)	$ (3,430)	$ (3,516)	$ (3,603)	$ (3,694)	$ (3,786)	$ (3,880)	$ (3,978)	$ (4,077)	$ (4,179)
Total Cost of Operations ($)	$ (20,077)	$ (20,579)	$ (21,093)	$ (21,621)	$ (22,161)	$ (22,715)	$ (23,283)	$ (23,865)	$ (24,462)	$ (25,073)
Operating Income	$ 89,591	$ 89,089	$ 88,574	$ 88,047	$ 87,506	$ 86,952	$ 86,384	$ 85,802	$ 85,206	$ 84,594
Debt Service										
Principal	$ (32,396)	$ (34,340)	$ (36,400)	$ (38,584)	$ (40,899)	$ (43,353)	$ (45,954)	$ (48,711)	$ (51,634)	$ (54,732)
Interest	$ (71,502)	$ (69,558)	$ (67,498)	$ (65,314)	$ (62,999)	$ (60,545)	$ (57,944)	$ (55,186)	$ (52,264)	$ (49,166)
Total Debt Service ($)	$ (103,898)	$ (103,898)	$ (103,898)	$ (103,898)	$ (103,898)	$ (103,898)	$ (103,898)	$ (103,898)	$ (103,898)	$ (103,898)
Project Revenues	$ (14,307)	$ (14,809)	$ (15,324)	$ (15,851)	$ (16,391)	$ (16,945)	$ (17,513)	$ (18,095)	$ (18,692)	$ (19,304)
Cash Flow for IRR Calculation	$ 89,591	$ 89,089	$ 88,574	$ 88,047	$ 87,506	$ 86,952	$ 86,384	$ 85,802	$ 85,206	$ 84,594
Cumulative Repayment	$ (1,197,644)	$ (1,178,113)	$ (1,157,037)	$ (1,134,304)	$ (1,109,796)	$ (1,083,389)	$ (1,054,948)	$ (1,024,332)	$ (991,390)	$ (955,962)
Present Value of Cash Flow	$ (7,989)	$ (7,801)	$ (7,615)	$ (7,432)	$ (7,250)	$ (7,071)	$ (6,894)	$ (6,720)	$ (6,549)	$ (6,380)
Debt Service Coverage	0.86	0.86	0.85	0.85	0.84	0.84	0.83	0.83	0.82	0.81
Payback period										

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
TOD Factors													
Super-Peak	1.090	1.090	1.130	1.130	1.130	2.010	2.010	2.010	2.010	1.090	1.090	1.090	
Shoulder	0.960	0.960	0.860	0.860	0.860	1.140	1.140	1.140	1.140	0.960	0.960	0.960	
Night	0.780	0.780	0.630	0.630	0.630	0.720	0.720	0.720	0.720	0.780	0.780	0.780	
TOD Prices													
Super-Peak	$ 127.86	$ 127.86	$ 132.55	$ 132.55	$ 132.55	$ 235.77	$ 235.77	$ 235.77	$ 235.77	$ 127.86	$ 127.86	$ 127.86	$ 1,980.02
Shoulder	$ 112.61	$ 112.61	$ 100.88	$ 100.88	$ 100.88	$ 133.72	$ 133.72	$ 133.72	$ 133.72	$ 112.61	$ 112.61	$ 112.61	$ 1,400.56
Night	$ 91.49	$ 91.49	$ 73.90	$ 73.90	$ 73.90	$ 84.46	$ 84.46	$ 84.46	$ 84.46	$ 91.49	$ 91.49	$ 91.49	$ 1,016.99
TOD Generation													
Super-Peak	6.4	9.9	12.4	20.8	24.9	28.5	27.7	29.4	24.9	13.3	6.5	10.9	215.5
Shoulder	10.7	16.6	22.4	37.5	44.8	43.5	38.8	44.9	46.8	37.9	18.7	18.4	380.9
Night	8.3	12.9	17.4	29.2	34.8	35.8	39.3	36.9	34.6	18.6	13.6	14.3	295.6
TOTAL	25.4	39.4	52.3	87.5	104.4	107.7	105.7	111.3	106.2	69.8	38.7	43.6	892.0
Revenue													
Super-Peak	$ 813	$ 1,260	$ 1,649	$ 2,761	$ 3,295	$ 6,719	$ 6,523	$ 6,943	$ 5,865	$ 1,697	$ 830	$ 1,395	$ 39,751
Shoulder	$ 1,205	$ 1,869	$ 2,259	$ 3,782	$ 4,514	$ 5,815	$ 5,184	$ 6,009	$ 6,258	$ 4,268	$ 2,101	$ 2,069	$ 45,333
Night	$ 762	$ 1,181	$ 1,287	$ 2,155	$ 2,572	$ 3,019	$ 3,320	$ 3,120	$ 2,920	$ 1,700	$ 1,240	$ 1,307	$ 24,583
TOTAL	$ 2,780	$ 4,310	$ 5,195	$ 8,697	$ 10,382	$ 15,553	$ 15,027	$ 16,072	$ 15,043	$ 7,665	$ 4,172	$ 4,772	$ 109,667
Weighted Average Price	$ 109.50	$ 109.50	$ 99.43	$ 99.43	$ 99.43	$ 144.37	$ 142.11	$ 144.37	$ 141.58	$ 109.89	$ 107.77	$ 109.50	$ 122.95

Source: PG&E Advice Letter 3410-E. January 27, 2009

	Length of Contract		
Start Year	10	15	20
2010	$ 101.75	$ 107.48	$ 113.90
2011	$ 104.00	$ 110.46	$ 117.30
2012	$ 106.98	$ 114.05	$ 121.26
2013	$ 109.98	$ 117.76	$ 125.27
2014	$ 112.78	$ 121.22	$ 128.97
2015	$ 116.05	$ 125.03	$ 132.90
2016	$ 119.71	$ 129.15	$ 137.06
2017	$ 123.67	$ 133.52	$ 141.44
2018	$ 128.02	$ 138.14	$ 146.03
2019	$ 132.71	$ 142.98	$ 150.80
2020	$ 137.76	$ 147.97	$ 155.78

Source: PG&E Advice Letter 3410-E. January 27, 2009

B2.3 Oak Ridge Tanks to Bass Lake Tanks Pumped Storage

Generation Estimate

	Total	*Super Peak* *(generation 6 hours summer and 8 hours non-summer)*							*Shoulder Peak*													
		Weekday							*Weekday* *(generation 3 hours non-summer months)*							*Weekend* *(generation 3 hours non-summer months)*						
	System Flow (cfs)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Power Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)
Jan	10.0	10.0	150	10.0	150	412	80%	48.0	10.0	150	10.0	0.0	412	80%	18.0	10.0	120	10.0	120	412	80%	26.4
Feb	10.0	10.0	130	10.0	130	412	80%	43.3	10.0	130	10.0	0.0	412	80%	16.2	10.0	110	10.0	110	412	80%	23.8
Mar	10.0	10.0	150	10.0	150	412	80%	48.0	10.0	150	10.0	0.0	412	80%	18.0	10.0	120	10.0	120	412	80%	26.4
Apr	10.0	10.0	140	10.0	140	412	80%	46.4	10.0	140	10.0	0.0	412	80%	17.4	10.0	110	10.0	110	412	80%	25.5
May	10.0	10.0	150	10.0	150	412	80%	48.0	10.0	150	10.0	0.0	412	80%	18.0	10.0	120	10.0	120	412	80%	26.4
Jun	10.0	10.0	140	10.0	140	412	80%	34.8	0.0	0	0.0	0.0	412	80%	0.0	10.0	110	10.0	110	412	80%	13.9
Jul	10.0	10.0	150	10.0	150	412	80%	36.0	0.0	0	0.0	0.0	412	80%	0.0	10.0	120	10.0	120	412	80%	14.4
Aug	10.0	10.0	150	10.0	150	412	80%	36.0	0.0	0	0.0	0.0	412	80%	0.0	10.0	120	10.0	120	412	80%	14.4
Sep	10.0	10.0	140	10.0	140	412	80%	34.8	0.0	0	0.0	0.0	412	80%	0.0	10.0	110	10.0	110	412	80%	13.9
Oct	10.0	10.0	150	10.0	150	412	80%	48.0	10.0	150	10.0	0.0	412	80%	18.0	10.0	120	10.0	120	412	80%	26.4
Nov	10.0	10.0	140	10.0	140	412	80%	46.4	10.0	140	10.0	0.0	412	80%	17.4	10.0	110	10.0	110	412	80%	25.5
Dec	10.0	10.0	150	10.0	150	412	80%	48.0	10.0	150	10.0	0.0	412	80%	18.0	10.0	120	10.0	120	412	80%	26.4
Total =	10.0	10.0	1,740	10.0	1,740	-	-	**520.0**	6.7	1,160	7	0	-	-	**140.0**	10.0	1,390	10	1,390	-	-	**260.0**

	Total	*Night* *(no generation during night)*																
		Weekday							*Weekend*									
	System Flow (cfs)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	2011-30 Generation* (mWh)	2011-40 Generation* (mWh)	2008 Generation* (mWh)
Jan	10.0	0.0	0	0.0	0	412	80%	0.0	0.0	0	0.0	0	412	80%	0.0	92	92	92
Feb	10.0	0.0	0	0.0	0	412	80%	0.0	0.0	0	0.0	0	412	80%	0.0	83	83	83
Mar	10.0	0.0	0	0.0	0	412	80%	0.0	0.0	0	0.0	0	412	80%	0.0	92	92	92
Apr	10.0	0.0	0	0.0	0	412	80%	0.0	0.0	0	0.0	0	412	80%	0.0	89	89	89
May	10.0	0.0	0	0.0	0	412	80%	0.0	0.0	0	0.0	0	412	80%	0.0	92	92	92
Jun	10.0	0.0	0	0.0	0	412	80%	0.0	0.0	0	0.0	0	412	80%	0.0	37	31	49
Jul	10.0	0.0	0	0.0	0	412	80%	0.0	0.0	0	0.0	0	412	80%	0.0	38	32	50
Aug	10.0	0.0	0	0.0	0	412	80%	0.0	0.0	0	0.0	0	412	80%	0.0	38	32	50
Sep	10.0	0.0	0	0.0	0	412	80%	0.0	0.0	0	0.0	0	412	80%	0.0	37	31	49
Oct	10.0	0.0	0	0.0	0	412	80%	0.0	0.0	0	0.0	0	412	80%	0.0	92	92	92
Nov	10.0	0.0	0	0.0	0	412	80%	0.0	0.0	0	0.0	0	412	80%	0.0	89	89	89
Dec	10.0	0.0	0	0.0	0	412	80%	0.0	0.0	0	0.0	0	412	80%	0.0	92	92	92
Total =	10.0	0.0	0	0	0	-	-	**0.0**	0.0	0	0	0	-	-	**0.0**	**870**	**850**	**920**

Assumptions:

Operate once a day, 70% of the days, year around.
10 cfs for 6 hours (about 1.62 million gallons)

Generating

Efficiency = 80%
Head = 412 feet

1 acre-feet = 325,851.429 US gallons
8.2 million gallons in two tanks
decrease storage as demands increase - if constrained.
Have about 1.6 million gallons available during summer months.
Have more storage available during non-summer months.
Use 10 cfs for 6 hours during the summer (about 1.62 million gallons)
Use 10 cfs for 11 hours during the non-summer months (about 2.96 million gallons)
Reduce generation in the summar as demands grow, reducing available storage.
Maintain non-summer operation for life of project.

B2.3 Oak Ridge Tanks to Bass Lake Tanks Pumped Storage

Capital Cost	$ 774,000	280	Plant Size (kW)	2.39%	IRR
First Year Annual O&M Costs	$ 5,183	874	Avg. Annual Gen (MWh)	$ (74,167)	NPV
First Year Annual A&I Costs	$ 1,254	$ 117.30	Baseline Market Price Referent ($/MWh)	>20	Payback Period (Years)
First Year Annual Repair & Replace Costs	$ 1,698	2011	Initial Year of Operation	36%	Capacity Factor
First Year Annual Contingency Costs	$ 1,627	30	Term of Debt (Years)	0.52	Minimum Annual Debt Service Coverage
Annual Costs Inflation Rate	2.50%	20	Length of Initial Contract (Years)	$ 134.33	Average Price Received ($/MWh)
Cost of Debt	6.00%	50	Project Physical Life (Years)	$ 886	Capital Cost per Avg Annual Generation ($/MWh)
Discount Rate	6.00%	1.50%	Finance Fee		

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Sales										
Generating Capacity (MW)	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Energy (MWH)	874	874	874	874	874	874	874	874	874	874
Energy Price ($/MWH)	$ 134.33	$ 134.33	$ 134.33	$ 134.33	$ 134.33	$ 134.33	$ 134.33	$ 134.33	$ 134.33	$ 134.33
Energy Sales Revenue ($)	$ 117,388	$ 117,388	$ 117,388	$ 117,388	$ 117,388	$ 117,388	$ 117,388	$ 117,388	$ 117,388	$ 117,388
Cost of Operations										
Operations & Maintenance	$ (5,183)	$ (5,313)	$ (5,445)	$ (5,582)	$ (5,721)	$ (5,864)	$ (6,011)	$ (6,161)	$ (6,315)	$ (6,473)
Administration & Insurance	$ (1,254)	$ (1,285)	$ (1,317)	$ (1,350)	$ (1,384)	$ (1,419)	$ (1,454)	$ (1,491)	$ (1,528)	$ (1,566)
Repair and Replacement	$ (1,698)	$ (1,740)	$ (1,784)	$ (1,829)	$ (1,874)	$ (1,921)	$ (1,969)	$ (2,018)	$ (2,069)	$ (2,121)
Contingency	$ (1,627)	$ (1,668)	$ (1,709)	$ (1,752)	$ (1,796)	$ (1,841)	$ (1,887)	$ (1,934)	$ (1,982)	$ (2,032)
Pumping Costs	$ (45,054)	$ (46,180)	$ (47,335)	$ (48,518)	$ (49,731)	$ (50,974)	$ (52,249)	$ (53,555)	$ (54,894)	$ (56,266)
Total Cost of Operations ($)	$ (54,816)	$ (56,186)	$ (57,591)	$ (59,031)	$ (60,506)	$ (62,019)	$ (63,569)	$ (65,159)	$ (66,788)	$ (68,457)
Operating Income	$ 62,572	$ 61,202	$ 59,797	$ 58,357	$ 56,882	$ 55,369	$ 53,819	$ 52,229	$ 50,600	$ 48,931
Debt Service										
Principal	$ (9,937)	$ (10,533)	$ (11,165)	$ (11,835)	$ (12,545)	$ (13,298)	$ (14,096)	$ (14,942)	$ (15,838)	$ (16,789)
Interest	$ (47,137)	$ (46,540)	$ (45,908)	$ (45,238)	$ (44,528)	$ (43,776)	$ (42,978)	$ (42,132)	$ (41,235)	$ (40,285)
Total Debt Service ($)	$ (57,074)	$ (57,074)	$ (57,074)	$ (57,074)	$ (57,074)	$ (57,074)	$ (57,074)	$ (57,074)	$ (57,074)	$ (57,074)
Project Revenues	$ 5,499	$ 4,128	$ 2,723	$ 1,284	$ (192)	$ (1,705)	$ (3,255)	$ (4,844)	$ (6,473)	$ (8,143)
Cash Flow for IRR Calculation	$ (723,038)	$ 61,202	$ 59,797	$ 58,357	$ 56,882	$ 55,369	$ 53,819	$ 52,229	$ 50,600	$ 48,931
Cumulative Repayment	$ (707,602)	$ (692,941)	$ (679,052)	$ (665,933)	$ (653,580)	$ (641,986)	$ (631,145)	$ (621,048)	$ (611,683)	$ (603,038)
Present Value of Cash Flow	$ 5,499	$ 3,894	$ 2,424	$ 1,078	$ (152)	$ (1,274)	$ (2,295)	$ (3,222)	$ (4,061)	$ (4,820)
Debt Service Coverage	1.10	1.07	1.05	1.02	1.00	0.97	0.94	0.92	0.89	0.86
Payback period										

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sales										
Generating Capacity (MW)	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Energy (MWH)	874	874	874	874	874	874	874	874	874	874
Energy Price ($/MWH)	$ 134.33	$ 134.33	$ 134.33	$ 134.33	$ 134.33	$ 134.33	$ 134.33	$ 134.33	$ 134.33	$ 134.33
Energy Sales Revenue ($)	$ 117,388	$ 117,388	$ 117,388	$ 117,388	$ 117,388	$ 117,388	$ 117,388	$ 117,388	$ 117,388	$ 117,388
Cost of Operations										
Operations & Maintenance	$ (6,635)	$ (6,801)	$ (6,971)	$ (7,145)	$ (7,323)	$ (7,507)	$ (7,694)	$ (7,887)	$ (8,084)	$ (8,286)
Administration & Insurance	$ (1,605)	$ (1,645)	$ (1,686)	$ (1,729)	$ (1,772)	$ (1,816)	$ (1,862)	$ (1,908)	$ (1,956)	$ (2,005)
Repair and Replacement	$ (2,174)	$ (2,228)	$ (2,284)	$ (2,341)	$ (2,399)	$ (2,459)	$ (2,521)	$ (2,584)	$ (2,648)	$ (2,715)
Contingency	$ (2,083)	$ (2,135)	$ (2,188)	$ (2,243)	$ (2,299)	$ (2,356)	$ (2,415)	$ (2,476)	$ (2,538)	$ (2,601)
Pumping Costs	$ (57,673)	$ (59,114)	$ (60,592)	$ (62,107)	$ (63,660)	$ (65,251)	$ (66,883)	$ (68,555)	$ (70,268)	$ (72,025)
Total Cost of Operations ($)	$ (70,169)	$ (71,923)	$ (73,721)	$ (75,564)	$ (77,453)	$ (79,390)	$ (81,374)	$ (83,409)	$ (85,494)	$ (87,631)
Operating Income	$ 47,219	$ 45,465	$ 43,667	$ 41,824	$ 39,935	$ 37,998	$ 36,014	$ 33,979	$ 31,894	$ 29,757
Debt Service										
Principal	$ (17,796)	$ (18,864)	$ (19,995)	$ (21,195)	$ (22,467)	$ (23,815)	$ (25,244)	$ (26,758)	$ (28,364)	$ (30,066)
Interest	$ (39,278)	$ (38,210)	$ (37,078)	$ (35,879)	$ (34,607)	$ (33,259)	$ (31,830)	$ (30,315)	$ (28,710)	$ (27,008)
Total Debt Service ($)	$ (57,074)	$ (57,074)	$ (57,074)	$ (57,074)	$ (57,074)	$ (57,074)	$ (57,074)	$ (57,074)	$ (57,074)	$ (57,074)
Project Revenues	$ (9,855)	$ (11,609)	$ (13,407)	$ (15,250)	$ (17,139)	$ (19,075)	$ (21,060)	$ (23,094)	$ (25,180)	$ (27,317)
Cash Flow for IRR Calculation	$ 47,219	$ 45,465	$ 43,667	$ 41,824	$ 39,935	$ 37,998	$ 36,014	$ 33,979	$ 31,894	$ 29,757
Cumulative Repayment	$ (595,096)	$ (587,842)	$ (581,253)	$ (575,308)	$ (569,980)	$ (565,240)	$ (561,056)	$ (557,392)	$ (554,208)	$ (551,459)
Present Value of Cash Flow	$ (5,503)	$ (6,115)	$ (6,663)	$ (7,150)	$ (7,581)	$ (7,959)	$ (8,290)	$ (8,576)	$ (8,822)	$ (9,029)
Debt Service Coverage	0.83	0.80	0.77	0.73	0.70	0.67	0.63	0.60	0.56	0.52
Payback period										

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
TOD Factors													
Super-Peak	1.090	1.090	1.130	1.130	1.130	2.010	2.010	2.010	2.010	1.090	1.090	1.090	
Shoulder	0.960	0.960	0.860	0.860	0.860	1.140	1.140	1.140	1.140	0.960	0.960	0.960	
Night	0.780	0.780	0.630	0.630	0.630	0.720	0.720	0.720	0.720	0.780	0.780	0.780	
TOD Prices													
Super-Peak	$ 127.86	$ 127.86	$ 132.55	$ 132.55	$ 132.55	$ 235.77	$ 235.77	$ 235.77	$ 235.77	$ 127.86	$ 127.86	$ 127.86	$ 1,980.02
Shoulder	$ 112.61	$ 112.61	$ 100.88	$ 100.88	$ 100.88	$ 133.72	$ 133.72	$ 133.72	$ 133.72	$ 112.61	$ 112.61	$ 112.61	$ 1,400.56
Night	$ 91.49	$ 91.49	$ 73.90	$ 73.90	$ 73.90	$ 84.46	$ 84.46	$ 84.46	$ 84.46	$ 91.49	$ 91.49	$ 91.49	$ 1,016.99
TOD Generation													
Super-Peak	48.0	43.3	48.0	46.4	48.0	26.4	27.3	27.3	26.4	48.0	46.4	48.0	483.2
Shoulder	44.4	40.1	44.4	42.9	44.4	10.6	10.9	10.9	10.6	44.4	42.9	44.4	390.6
Night	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL	92.3	83.4	92.3	89.3	92.3	37.0	38.2	38.2	37.0	92.3	89.3	92.3	873.9
Revenue													
Super-Peak	$ 6,131	$ 5,538	$ 6,356	$ 6,151	$ 6,356	$ 6,223	$ 6,430	$ 6,430	$ 6,223	$ 6,131	$ 5,934	$ 6,131	$ 74,036
Shoulder	$ 4,995	$ 4,512	$ 4,475	$ 4,330	$ 4,475	$ 1,412	$ 1,459	$ 1,459	$ 1,412	$ 4,995	$ 4,834	$ 4,995	$ 43,352
Night	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL	$ 11,126	$ 10,050	$ 10,831	$ 10,482	$ 10,831	$ 7,635	$ 7,888	$ 7,888	$ 7,635	$ 11,126	$ 10,768	$ 11,126	$ 117,388
Weighted Average Price	$ 120.53	$ 120.53	$ 117.33	$ 117.33	$ 117.33	$ 206.62	$ 206.62	$ 206.62	$ 206.62	$ 120.53	$ 120.53	$ 120.53	$ 134.33

Source: PG&E Advice Letter 3410-E. January 27, 2009

	Length of Contract		
Start Year	10	15	20
2010	$ 101.75	$ 107.48	$ 113.90
2011	$ 104.00	$ 110.46	$ 117.30
2012	$ 106.98	$ 114.05	$ 121.26
2013	$ 109.98	$ 117.76	$ 125.27
2014	$ 112.78	$ 121.22	$ 128.97
2015	$ 116.05	$ 125.03	$ 132.90
2016	$ 119.71	$ 129.15	$ 137.06
2017	$ 123.67	$ 133.52	$ 141.44
2018	$ 128.02	$ 138.14	$ 146.03
2019	$ 132.71	$ 142.98	$ 150.80
2020	$ 137.76	$ 147.97	$ 155.78

Source: PG&E Advice Letter 3410-E. January 27, 2009

B2.4 Sandtrap Siphon

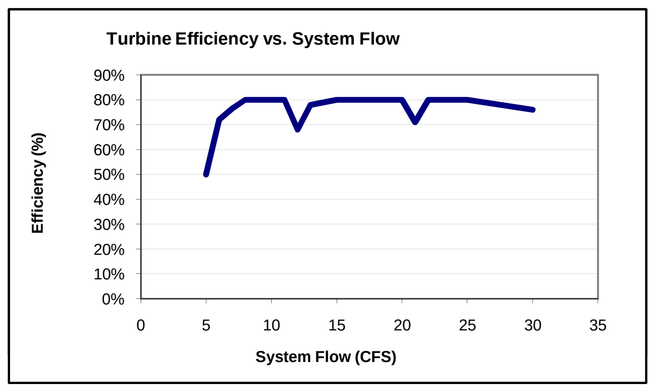
	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Power Generation* (mWh)
Jan	7	400	7	400	137	77%	45
Feb	7	400	7	400	137	77%	41
Mar	7	400	7	400	137	77%	45
Apr	7	400	7	400	137	77%	44
May	30	1,800	30	1,800	120	76%	167
Jun	30	1,800	30	1,800	120	76%	162
Jul	30	1,800	30	1,800	120	76%	167
Aug	30	1,800	30	1,800	120	76%	167
Sep	30	1,800	30	1,800	120	76%	162
Oct	7	400	7	400	137	77%	45
Nov	7	400	7	400	137	77%	44
Dec	7	400	7	400	137	77%	45
Total =	17	11,800	17	11,800	-	-	**1,130**

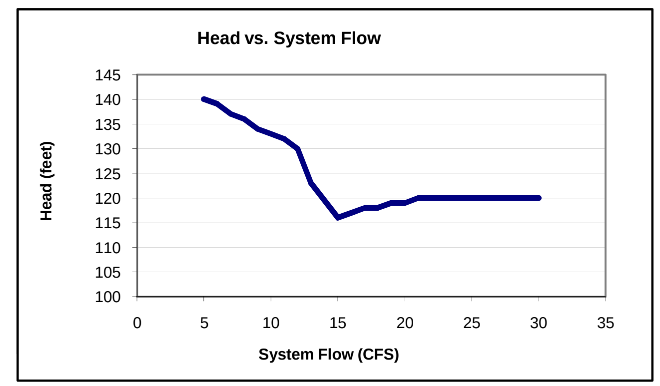
* Assumed at 97% of flow available for generation.

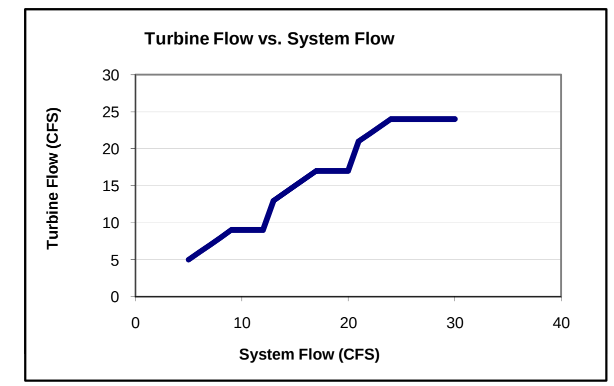
Efficiency

Sand Trap

System Flow (cfs)	Turbine Flow (cfs)	Head (ft)	Eff (%)
5	5	140	50%
6	6	139	72%
7	7	137	77%
8	8	136	80%
9	9	134	80%
10	9	133	80%
11	9	132	80%
12	9	130	68%
13	13	123	78%
15	15	116	80%
16	16	117	80%
17	17	118	80%
18	17	118	80%
19	17	119	80%
20	17	119	80%
21	21	120	71%
22	22	120	80%
23	23	120	80%
24	24	120	80%
25	24	120	80%
30	24	120	76%







B2.4 Sandtrap Siphon

Capital Cost	$ 1,456,000	232	Plant Size (kW)	5.96%	IRR
First Year Annual O&M Costs	$ 7,058	1,130	Avg. Annual Gen (MWh)	$ 158,462	NPV
First Year Annual A&I Costs	$ 3,201	$ 117.30	Baseline Market Price Referent ($/MWh)	25	Payback Period (Years)
First Year Annual Repair & Replace Costs	$ 3,129	2011	Initial Year of Operation	56%	Capacity Factor
First Year Annual Contingency Costs	$ 2,678	30	Term of Debt (Years)	1.07	Minimum Annual Debt Service Coverage
Annual Costs Inflation Rate	2.50%	20	Length of Initial Contract (Years)	$ 124.56	Average Price Received ($/MWh)
Cost of Debt	6.00%		Project Physical Life (Years)	$ 1,288	Capital Cost per Avg Annual Generation ($/MWh)
Discount Rate	6.00%	1.50%	Finance Fee		
Term of CREBs/QECBs (if applicable)		70.00%	CREBs/QECB Subsidy		

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Sales										
Generating Capacity (MW)	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Energy (MWH)	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130
Energy Price ($/MWH)	$ 124.56	$ 124.56	$ 124.56	$ 124.56	$ 124.56	$ 124.56	$ 124.56	$ 124.56	$ 124.56	$ 124.56
Energy Sales Revenue ($)	$ 140,752	$ 140,752	$ 140,752	$ 140,752	$ 140,752	$ 140,752	$ 140,752	$ 140,752	$ 140,752	$ 140,752
Cost of Operations										
Operations & Maintenance	$ (7,058)	$ (7,234)	$ (7,415)	$ (7,601)	$ (7,791)	$ (7,985)	$ (8,185)	$ (8,390)	$ (8,599)	$ (8,814)
Administration & Insurance	$ (3,201)	$ (3,281)	$ (3,363)	$ (3,447)	$ (3,533)	$ (3,622)	$ (3,712)	$ (3,805)	$ (3,900)	$ (3,998)
Repair and Replacement	$ (3,129)	$ (3,207)	$ (3,287)	$ (3,370)	$ (3,454)	$ (3,540)	$ (3,629)	$ (3,719)	$ (3,812)	$ (3,908)
Contingency	$ (2,678)	$ (2,745)	$ (2,814)	$ (2,884)	$ (2,956)	$ (3,030)	$ (3,106)	$ (3,183)	$ (3,263)	$ (3,344)
Total Cost of Operations ($)	$ (16,066)	$ (16,468)	$ (16,879)	$ (17,301)	$ (17,734)	$ (18,177)	$ (18,632)	$ (19,097)	$ (19,575)	$ (20,064)
Operating Income	$ 124,686	$ 124,284	$ 123,872	$ 123,450	$ 123,018	$ 122,574	$ 122,120	$ 121,654	$ 121,177	$ 120,687
Debt Service										
Principal	$ (18,693)	$ (19,815)	$ (21,004)	$ (22,264)	$ (23,600)	$ (25,016)	$ (26,516)	$ (28,107)	$ (29,794)	$ (31,582)
Interest	$ (88,670)	$ (87,549)	$ (86,360)	$ (85,100)	$ (83,764)	$ (82,348)	$ (80,847)	$ (79,256)	$ (77,570)	$ (75,782)
CREB/QECB Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Debt Service ($)	$ (107,363)	$ (107,363)	$ (107,363)	$ (107,363)	$ (107,363)	$ (107,363)	$ (107,363)	$ (107,363)	$ (107,363)	$ (107,363)
Project Revenues	$ 17,322	$ 16,921	$ 16,509	$ 16,087	$ 15,654	$ 15,211	$ 14,757	$ 14,291	$ 13,813	$ 13,324
Cash Flow for IRR Calculation	$ (1,353,154)	$ 124,284	$ 123,872	$ 123,450	$ 123,018	$ 122,574	$ 122,120	$ 121,654	$ 121,177	$ 120,687
Cumulative Repayment	$ (1,317,139)	$ (1,280,404)	$ (1,242,892)	$ (1,204,541)	$ (1,165,287)	$ (1,125,061)	$ (1,083,788)	$ (1,041,390)	$ (997,782)	$ (952,877)
Present Value of Cash Flow	$ 17,322	$ 15,963	$ 14,693	$ 13,507	$ 12,400	$ 11,367	$ 10,403	$ 9,504	$ 8,667	$ 7,886
Debt Service Coverage	1.16	1.16	1.15	1.15	1.15	1.14	1.14	1.13	1.13	1.12
Payback period										

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sales										
Generating Capacity (MW)	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Energy (MWH)	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130
Energy Price ($/MWH)	$ 124.56	$ 124.56	$ 124.56	$ 124.56	$ 124.56	$ 124.56	$ 124.56	$ 124.56	$ 124.56	$ 124.56
Energy Sales Revenue ($)	$ 140,752	$ 140,752	$ 140,752	$ 140,752	$ 140,752	$ 140,752	$ 140,752	$ 140,752	$ 140,752	$ 140,752
Cost of Operations										
Operations & Maintenance	$ (9,035)	$ (9,261)	$ (9,492)	$ (9,730)	$ (9,973)	$ (10,222)	$ (10,478)	$ (10,740)	$ (11,008)	$ (11,283)
Administration & Insurance	$ (4,098)	$ (4,200)	$ (4,305)	$ (4,413)	$ (4,523)	$ (4,636)	$ (4,752)	$ (4,871)	$ (4,992)	$ (5,117)
Repair and Replacement	$ (4,005)	$ (4,106)	$ (4,208)	$ (4,313)	$ (4,421)	$ (4,532)	$ (4,645)	$ (4,761)	$ (4,880)	$ (5,002)
Contingency	$ (3,428)	$ (3,514)	$ (3,602)	$ (3,692)	$ (3,784)	$ (3,879)	$ (3,976)	$ (4,075)	$ (4,177)	$ (4,281)
Total Cost of Operations ($)	$ (20,566)	$ (21,080)	$ (21,607)	$ (22,147)	$ (22,701)	$ (23,268)	$ (23,850)	$ (24,446)	$ (25,057)	$ (25,684)
Operating Income	$ 120,186	$ 119,672	$ 119,145	$ 118,604	$ 118,051	$ 117,483	$ 116,902	$ 116,305	$ 115,694	$ 115,068
Debt Service										
Principal	$ (33,476)	$ (35,485)	$ (37,614)	$ (39,871)	$ (42,263)	$ (44,799)	$ (47,487)	$ (50,336)	$ (53,356)	$ (56,558)
Interest	$ (73,887)	$ (71,878)	$ (69,749)	$ (67,492)	$ (65,100)	$ (62,564)	$ (59,877)	$ (57,027)	$ (54,007)	$ (50,806)
CREB/QECB Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Total Debt Service ($)	$ (107,363)	$ (107,363)	$ (107,363)	$ (107,363)	$ (107,363)	$ (107,363)	$ (107,363)	$ (107,363)	$ (107,363)	(107,363)
Project Revenues	$ 12,822	$ 12,308	$ 11,781	$ 11,241	$ 10,687	$ 10,120	$ 9,538	$ 8,942	$ 8,331	7,704
Cash Flow for IRR Calculation	$ 120,186	$ 119,672	$ 119,145	$ 118,604	$ 118,051	$ 117,483	$ 116,902	$ 116,305	$ 115,694	115,068
Cumulative Repayment	$ (906,578)	$ (858,785)	$ (809,390)	$ (758,278)	$ (705,327)	$ (650,408)	$ (593,383)	$ (534,105)	$ (472,418)	(408,156)
Present Value of Cash Flow	$ 7,160	$ 6,484	$ 5,855	$ 5,270	$ 4,727	$ 4,223	$ 3,755	$ 3,321	$ 2,919	2,546
Debt Service Coverage	1.12	1.11	1.11	1.10	1.10	1.09	1.09	1.08	1.08	1.07
Payback period										

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
TOD Factors													
Super-Peak	1.090	1.090	1.130	1.130	1.130	2.010	2.010	2.010	2.010	1.090	1.090	1.090	
Shoulder	0.960	0.960	0.860	0.860	0.860	1.140	1.140	1.140	1.140	0.960	0.960	0.960	
Night	0.780	0.780	0.630	0.630	0.630	0.720	0.720	0.720	0.720	0.780	0.780	0.780	
TOD Prices													
Super-Peak	$ 127.86	$ 127.86	$ 132.55	$ 132.55	$ 132.55	$ 235.77	$ 235.77	$ 235.77	$ 235.77	$ 127.86	$ 127.86	$ 127.86	$ 1,980.02
Shoulder	$ 112.61	$ 112.61	$ 100.88	$ 100.88	$ 100.88	$ 133.72	$ 133.72	$ 133.72	$ 133.72	$ 112.61	$ 112.61	$ 112.61	$ 1,400.56
Night	$ 91.49	$ 91.49	$ 73.90	$ 73.90	$ 73.90	$ 84.46	$ 84.46	$ 84.46	$ 84.46	$ 91.49	$ 91.49	$ 91.49	$ 1,016.99
TOD Generation													
Super-Peak	10.7	9.7	10.7	10.4	31.8	30.8	31.8	31.8	30.8	10.7	10.4	10.7	230.6
Shoulder	19.3	17.5	19.3	18.7	57.3	55.5	57.3	57.3	55.5	19.3	18.7	19.3	415.2
Night	15.0	13.6	15.0	14.6	44.6	43.1	44.6	44.6	43.1	15.0	14.6	15.0	322.9
TOTAL	45.1	40.8	45.1	43.7	133.8	129.4	133.8	133.8	129.4	45.1	43.7	45.1	968.7
Revenue													
Super-Peak	$ 1,374	$ 1,241	$ 1,424	$ 1,378	$ 4,221	$ 7,266	$ 7,508	$ 7,508	$ 7,266	$ 1,374	$ 1,329	$ 1,374	$ 43,263
Shoulder	$ 2,178	$ 1,967	$ 1,951	$ 1,888	$ 5,783	$ 7,418	$ 7,665	$ 7,665	$ 7,418	$ 2,178	$ 2,107	$ 2,178	$ 50,395
Night	$ 1,376	$ 1,243	$ 1,112	$ 1,076	$ 3,295	$ 3,644	$ 3,765	$ 3,765	$ 3,644	$ 1,376	$ 1,332	$ 1,376	$ 27,004
TOTAL	$ 4,928	$ 4,451	$ 4,486	$ 4,342	$ 13,298	$ 18,328	$ 18,939	$ 18,939	$ 18,328	$ 4,928	$ 4,769	$ 4,928	$ 120,663
Weighted Average Price	$ 109.20	$ 109.20	$ 99.43	$ 99.43	$ 99.43	$ 141.60	$ 141.60	$ 141.60	$ 141.60	$ 109.20	$ 109.20	$ 109.20	$ 124.56

Source: PG&E Advice Letter

Source: PG&E Advice Letter 3410-E. January 27, 2009

	Length of Contract		
Start Year	10	15	20
2010	$ 101.75	$ 107.48	$ 113.90
2011	$ 104.00	$ 110.46	$ 117.30
2012	$ 106.98	$ 114.05	$ 121.26
2013	$ 109.98	$ 117.76	$ 125.27
2014	$ 112.78	$ 121.22	$ 128.97
2015	$ 116.05	$ 125.03	$ 132.90
2016	$ 119.71	$ 129.15	$ 137.06
2017	$ 123.67	$ 133.52	$ 141.44
2018	$ 128.02	$ 138.14	$ 146.03
2019	$ 132.71	$ 142.98	$ 150.80
2020	$ 137.76	$ 147.97	$ 155.78

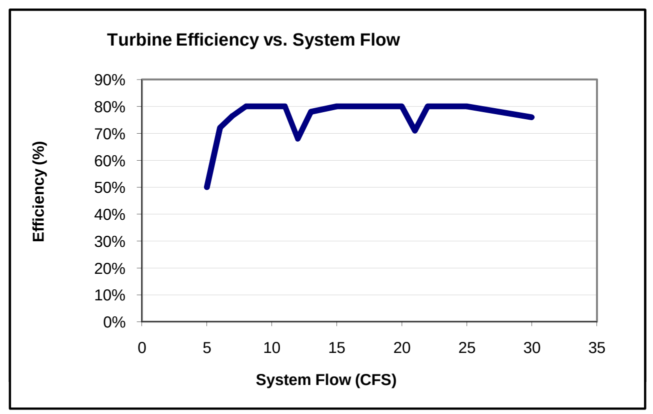
B2.5 Buffalo Hill Siphon

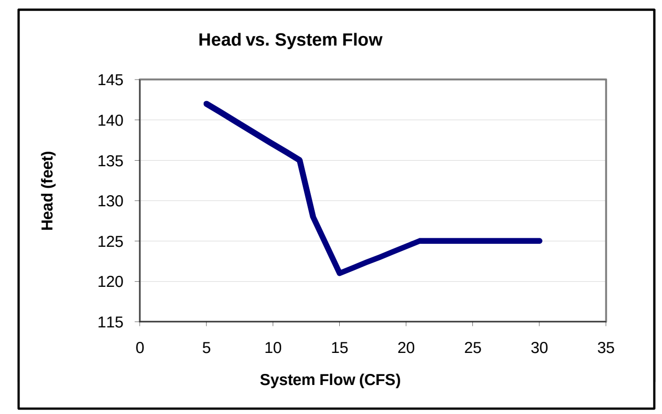
	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Power Generation* (mWh)
Jan	6	400	6	400	141	72%	37
Feb	6	300	6	300	141	72%	34
Mar	6	400	6	400	141	72%	37
Apr	6	400	6	400	141	72%	36
May	20	1,200	20	1,200	124	80%	121
Jun	20	1,200	20	1,200	124	80%	117
Jul	20	1,200	20	1,200	124	80%	121
Aug	20	1,200	20	1,200	124	80%	121
Sep	20	1,200	20	1,200	124	80%	117
Oct	6	400	6	400	141	72%	37
Nov	6	400	6	400	141	72%	36
Dec	6	400	6	400	141	72%	37
Total =	12	8,700	12	8,700	-	-	**850**

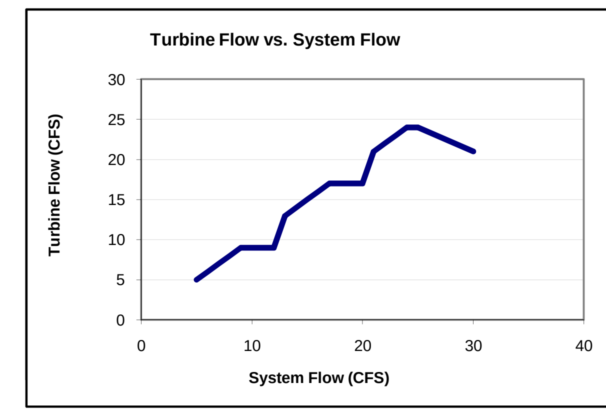
* Assumed at 97% of flow available for generation.

Efficiency

System Flow (cfs)	Turbine Flow (cfs)	Head (ft)	Eff (%)
5	5	142	50%
6	6	141	72%
7	7	140	77%
8	8	139	80%
9	9	138	80%
10	9	137	80%
11	9	136	80%
12	9	135	68%
13	13	128	78%
15	15	121	80%
16	16	122	80%
17	17	122	80%
18	17	123	80%
19	17	124	80%
20	17	124	80%
21	21	125	71%
22	22	125	80%
23	23	125	80%
24	24	125	80%
25	24	125	80%
30	21	125	76%







B2.5 Buffalo Hill Siphon

Capital Cost	$ 1,284,000	168	Plant Size (kW)	3.46%	IRR
First Year Annual O&M Costs	$ 7,058	860	Avg. Annual Gen (MWh)	$ (69,292)	NPV
First Year Annual A&I Costs	$ 2,508	$ 117.30	Baseline Market Price Referent ($/MWh)	>30	Payback Period (Years)
First Year Annual Repair & Replace Costs	$ 2,841	2011	Initial Year of Operation	58%	Capacity Factor
First Year Annual Contingency Costs	$ 2,481	30	Term of Debt (Years)	0.88	Minimum Annual Debt Service Coverage
Annual Costs Inflation Rate	2.50%	20	Length of Initial Contract (Years)	$ 124.16	Average Price Received ($/MWh)
Cost of Debt	6.00%		Project Physical Life (Years)	$ 1,493	Capital Cost per Avg Annual Generation ($/MWh)
Discount Rate	6.00%	1.50%	Finance Fee		
Term of CREBs/QECBs (if applicable)		70.00%	CREBs/QECB Subsidy		

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Sales										
Generating Capacity (MW)	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Energy (MWH)	860	860	860	860	860	860	860	860	860	860
Energy Price ($/MWH)	$ 124.16	$ 124.16	$ 124.16	$ 124.16	$ 124.16	$ 124.16	$ 124.16	$ 124.16	$ 124.16	$ 124.16
Energy Sales Revenue ($)	$ 106,777	$ 106,777	$ 106,777	$ 106,777	$ 106,777	$ 106,777	$ 106,777	$ 106,777	$ 106,777	$ 106,777
Cost of Operations										
Operations & Maintenance	$ (7,058)	$ (7,234)	$ (7,415)	$ (7,601)	$ (7,791)	$ (7,985)	$ (8,185)	$ (8,390)	$ (8,599)	$ (8,814)
Administration & Insurance	$ (2,508)	$ (2,571)	$ (2,635)	$ (2,701)	$ (2,768)	$ (2,838)	$ (2,909)	$ (2,981)	$ (3,056)	$ (3,132)
Repair and Replacement	$ (2,841)	$ (2,912)	$ (2,985)	$ (3,059)	$ (3,136)	$ (3,214)	$ (3,295)	$ (3,377)	$ (3,461)	$ (3,548)
Contingency	$ (2,481)	$ (2,543)	$ (2,607)	$ (2,672)	$ (2,739)	$ (2,807)	$ (2,877)	$ (2,949)	$ (3,023)	$ (3,098)
Total Cost of Operations ($)	$ (14,888)	$ (15,260)	$ (15,642)	$ (16,033)	$ (16,434)	$ (16,844)	$ (17,266)	$ (17,697)	$ (18,140)	$ (18,593)
Operating Income	$ 91,889	$ 91,517	$ 91,135	$ 90,744	$ 90,343	$ 89,932	$ 89,511	$ 89,080	$ 88,637	$ 88,184
Debt Service										
Principal	$ (16,485)	$ (17,474)	$ (18,522)	$ (19,634)	$ (20,812)	$ (22,060)	$ (23,384)	$ (24,787)	$ (26,274)	$ (27,851)
Interest	$ (78,196)	$ (77,207)	$ (76,158)	$ (75,047)	$ (73,869)	$ (72,620)	$ (71,296)	$ (69,893)	$ (68,406)	$ (66,830)
CREB/QECB Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Debt Service ($)	$ (94,680)	$ (94,680)	$ (94,680)	$ (94,680)	$ (94,680)	$ (94,680)	$ (94,680)	$ (94,680)	$ (94,680)	$ (94,680)
Project Revenues	$ (2,792)	$ (3,164)	$ (3,545)	$ (3,936)	$ (4,337)	$ (4,748)	$ (5,169)	$ (5,601)	$ (6,043)	$ (6,497)
Cash Flow for IRR Calculation	$ (1,211,371)	$ 91,517	$ 91,135	$ 90,744	$ 90,343	$ 89,932	$ 89,511	$ 89,080	$ 88,637	$ 88,184
Cumulative Repayment	$ (1,197,678)	$ (1,183,368)	$ (1,168,391)	$ (1,152,693)	$ (1,136,219)	$ (1,118,906)	$ (1,100,691)	$ (1,081,505)	$ (1,061,274)	$ (1,039,920)
Present Value of Cash Flow	$ (2,792)	$ (2,985)	$ (3,155)	$ (3,305)	$ (3,435)	$ (3,548)	$ (3,644)	$ (3,725)	$ (3,792)	$ (3,845)
Debt Service Coverage	0.97	0.97	0.96	0.96	0.95	0.95	0.95	0.94	0.94	0.93
Payback period										

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sales										
Generating Capacity (MW)	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Energy (MWH)	860	860	860	860	860	860	860	860	860	860
Energy Price ($/MWH)	$ 124.16	$ 124.16	$ 124.16	$ 124.16	$ 124.16	$ 124.16	$ 124.16	$ 124.16	$ 124.16	$ 124.16
Energy Sales Revenue ($)	$ 106,777	$ 106,777	$ 106,777	$ 106,777	$ 106,777	$ 106,777	$ 106,777	$ 106,777	$ 106,777	$ 106,777
Cost of Operations										
Operations & Maintenance	$ (9,035)	$ (9,261)	$ (9,492)	$ (9,730)	$ (9,973)	$ (10,222)	$ (10,478)	$ (10,740)	$ (11,008)	$ (11,283)
Administration & Insurance	$ (3,210)	$ (3,291)	$ (3,373)	$ (3,457)	$ (3,544)	$ (3,632)	$ (3,723)	$ (3,816)	$ (3,912)	$ (4,009)
Repair and Replacement	$ (3,637)	$ (3,728)	$ (3,821)	$ (3,916)	$ (4,014)	$ (4,115)	$ (4,217)	$ (4,323)	$ (4,431)	$ (4,542)
Contingency	$ (3,176)	$ (3,255)	$ (3,337)	$ (3,420)	$ (3,506)	$ (3,593)	$ (3,683)	$ (3,775)	$ (3,870)	$ (3,966)
Total Cost of Operations ($)	$ (19,058)	$ (19,534)	$ (20,023)	$ (20,523)	$ (21,036)	$ (21,562)	$ (22,101)	$ (22,654)	$ (23,220)	$ (23,801)
Operating Income	$ 87,719	$ 87,243	$ 86,754	$ 86,254	$ 85,740	$ 85,215	$ 84,676	$ 84,123	$ 83,557	$ 82,976
Debt Service										
Principal	$ (29,522)	$ (31,293)	$ (33,171)	$ (35,161)	$ (37,271)	$ (39,507)	$ (41,877)	$ (44,390)	$ (47,053)	$ (49,876)
Interest	$ (65,159)	$ (63,387)	$ (61,510)	$ (59,519)	$ (57,410)	$ (55,174)	$ (52,803)	$ (50,291)	$ (47,627)	$ (44,804)
CREB/QECB Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Debt Service ($)	$ (94,680)	$ (94,680)	$ (94,680)	$ (94,680)	$ (94,680)	$ (94,680)	$ (94,680)	$ (94,680)	$ (94,680)	$ (94,680)
Project Revenues	$ (6,961)	$ (7,438)	$ (7,926)	$ (8,427)	$ (8,940)	$ (9,466)	$ (10,005)	$ (10,557)	$ (11,124)	$ (11,704)
Cash Flow for IRR Calculation	$ 87,719	$ 87,243	$ 86,754	$ 86,254	$ 85,740	$ 85,215	$ 84,676	$ 84,123	$ 83,557	$ 82,976
Cumulative Repayment	$ (1,017,359)	$ (993,504)	$ (968,260)	$ (941,526)	$ (913,195)	$ (883,154)	$ (851,282)	$ (817,449)	$ (781,520)	$ (743,348)
Present Value of Cash Flow	$ (3,887)	$ (3,918)	$ (3,939)	$ (3,951)	$ (3,954)	$ (3,950)	$ (3,938)	$ (3,921)	$ (3,897)	$ (3,868)
Debt Service Coverage	0.93	0.92	0.92	0.91	0.91	0.90	0.89	0.89	0.88	0.88
Payback period										

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
TOD Factors													
Super-Peak	1.090	1.090	1.130	1.130	1.130	2.010	2.010	2.010	2.010	1.090	1.090	1.090	
Shoulder	0.960	0.960	0.860	0.860	0.860	1.140	1.140	1.140	1.140	0.960	0.960	0.960	
Night	0.780	0.780	0.630	0.630	0.630	0.720	0.720	0.720	0.720	0.780	0.780	0.780	
TOD Prices													
Super-Peak	$ 127.86	$ 127.86	$ 132.55	$ 132.55	$ 132.55	$ 235.77	$ 235.77	$ 235.77	$ 235.77	$ 127.86	$ 127.86	$ 127.86	$ 1,980.02
Shoulder	$ 112.61	$ 112.61	$ 100.88	$ 100.88	$ 100.88	$ 133.72	$ 133.72	$ 133.72	$ 133.72	$ 112.61	$ 112.61	$ 112.61	$ 1,400.56
Night	$ 91.49	$ 91.49	$ 73.90	$ 73.90	$ 73.90	$ 84.46	$ 84.46	$ 84.46	$ 84.46	$ 91.49	$ 91.49	$ 91.49	$ 1,016.99
TOD Generation													
Super-Peak	8.9	8.0	8.9	8.6	24.5	23.7	24.5	24.5	23.7	8.9	8.6	8.9	181.7
Shoulder	16.0	14.4	16.0	15.4	44.2	42.7	44.2	44.2	42.7	16.0	15.4	16.0	327.1
Night	12.4	11.2	12.4	12.0	34.4	33.2	34.4	34.4	33.2	12.4	12.0	12.4	254.4
TOTAL	37.2	33.6	37.2	36.0	103.1	99.7	103.1	103.1	99.7	37.2	36.0	37.2	763.2
Revenue													
Super-Peak	$ 1,133	$ 1,023	$ 1,175	$ 1,137	$ 3,252	$ 5,598	$ 5,785	$ 5,785	$ 5,598	$ 1,133	$ 1,097	$ 1,133	$ 33,850
Shoulder	$ 1,796	$ 1,623	$ 1,609	$ 1,557	$ 4,455	$ 5,715	$ 5,906	$ 5,906	$ 5,715	$ 1,796	$ 1,738	$ 1,796	$ 39,614
Night	$ 1,135	$ 1,025	$ 917	$ 887	$ 2,538	$ 2,808	$ 2,901	$ 2,901	$ 2,808	$ 1,135	$ 1,099	$ 1,135	$ 21,289
TOTAL	$ 4,065	$ 3,671	$ 3,701	$ 3,581	$ 10,246	$ 14,121	$ 14,592	$ 14,592	$ 14,121	$ 4,065	$ 3,934	$ 4,065	$ 94,753
Weighted Average Price	$ 109.20	$ 109.20	$ 99.43	$ 99.43	$ 99.43	$ 141.60	$ 141.60	$ 141.60	$ 141.60	$ 109.20	$ 109.20	$ 109.20	$ 124.16

Source: PG&E Advice Letter

Source: PG&E Advice Letter 3410-E. January 27, 2009

	Length of Contract		
Start Year	10	15	20
2010	$ 101.75	$ 107.48	$ 113.90
2011	$ 104.00	$ 110.46	$ 117.30
2012	$ 106.98	$ 114.05	$ 121.26
2013	$ 109.98	$ 117.76	$ 125.27
2014	$ 112.78	$ 121.22	$ 128.97
2015	$ 116.05	$ 125.03	$ 132.90
2016	$ 119.71	$ 129.15	$ 137.06
2017	$ 123.67	$ 133.52	$ 141.44
2018	$ 128.02	$ 138.14	$ 146.03
2019	$ 132.71	$ 142.98	$ 150.80
2020	$ 137.76	$ 147.97	$ 155.78

B2.6 Kaiser Siphon

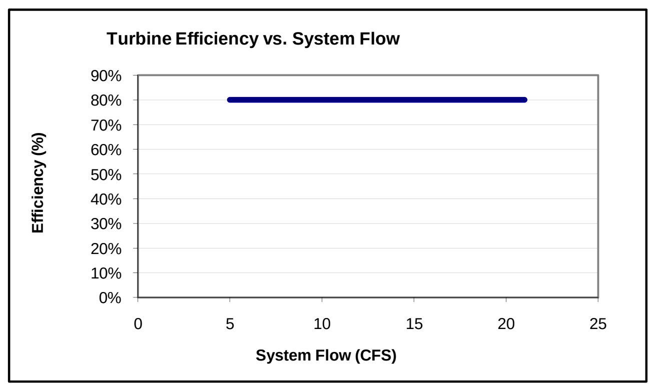
	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Power Generation* (mWh)
Jan	6	400	6	400	668	80%	196
Feb	6	300	6	300	668	80%	177
Mar	6	400	6	400	668	80%	196
Apr	6	400	6	400	668	80%	190
May	15	900	15	900	635	80%	466
Jun	15	900	15	900	635	80%	451
Jul	15	900	15	900	635	80%	466
Aug	15	900	15	900	635	80%	466
Sep	15	900	15	900	635	80%	451
Oct	6	400	6	400	668	80%	196
Nov	6	400	6	400	668	80%	190
Dec	6	400	6	400	668	80%	196
Total =	10	7,200	10	7,200	-	-	**3,640**

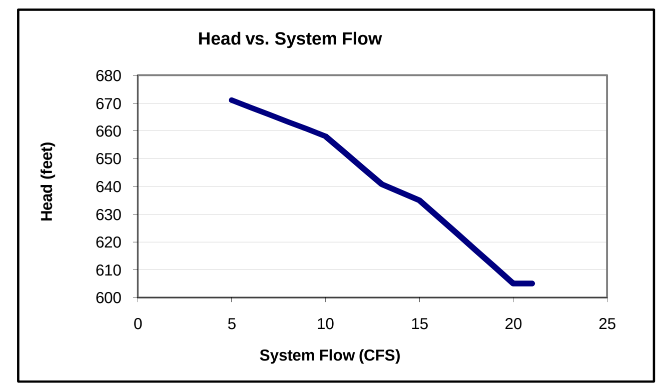
* Assumed at 97% of flow available for generation.

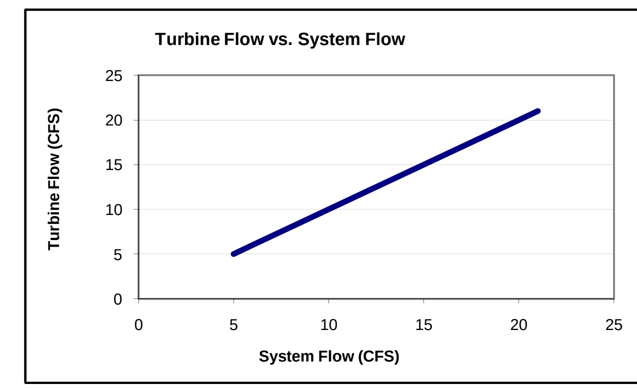
Efficiency

System Flow (cfs)	Turbine Flow (cfs)	Head (ft)	Eff (%)
5	5	671	80%
6	6	668	80%
7	7	666	80%
8	8	663	80%
9	9	661	80%
10	10	658	80%
11	11	652	80%
12	12	647	80%
13	13	641	80%
15	15	635	80%
16	16	629	80%
17	17	623	80%
18	18	617	80%
19	19	611	80%
20	20	605	80%
21	21	605	80%

Static head = 675'







B2.6 Kaiser Siphon

Capital Cost	$ 5,172,000	580	Plant Size (kW)	5.34%	IRR
First Year Annual O&M Costs	$ 6,558	3,638	Avg. Annual Gen (MWh)	$ 347,616	NPV
First Year Annual A&I Costs	$ 11,880	$ 117.30	Baseline Market Price Referent ($/MWh)	>20	Payback Period (Years)
First Year Annual Repair & Replace Costs	$ 6,630	2011	Initial Year of Operation	72%	Capacity Factor
First Year Annual Contingency Costs	$ 5,014	30	Term of Debt (Years)	1.05	Minimum Annual Debt Service Coverage
Annual Costs Inflation Rate	2.50%	20	Length of Initial Contract (Years)	$ 123.23	Average Price Received ($/MWh)
Cost of Debt	6.00%	50	Project Physical Life (Years)	$ 1,422	Capital Cost per Avg Annual Generation ($/MWh)
Discount Rate	6.00%	1.50%	Finance Fee		

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Sales										
Generating Capacity (MW)	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
Energy (MWH)	3,638	3,638	3,638	3,638	3,638	3,638	3,638	3,638	3,638	3,638
Energy Price ($/MWH)	$ 123.23	$ 123.23	$ 123.23	$ 123.23	$ 123.23	$ 123.23	$ 123.23	$ 123.23	$ 123.23	$ 123.23
Energy Sales Revenue ($)	$ 448,331	$ 448,331	$ 448,331	$ 448,331	$ 448,331	$ 448,331	$ 448,331	$ 448,331	$ 448,331	$ 448,331
Cost of Operations										
Operations & Maintenance	$ (6,558)	$ (6,722)	$ (6,890)	$ (7,062)	$ (7,239)	$ (7,420)	$ (7,605)	$ (7,795)	$ (7,990)	$ (8,190)
Administration & Insurance	$ (11,880)	$ (12,177)	$ (12,481)	$ (12,793)	$ (13,113)	$ (13,441)	$ (13,777)	$ (14,122)	$ (14,475)	$ (14,836)
Repair and Replacement	$ (6,630)	$ (6,796)	$ (6,966)	$ (7,140)	$ (7,318)	$ (7,501)	$ (7,689)	$ (7,881)	$ (8,078)	$ (8,280)
Contingency	$ (5,014)	$ (5,139)	$ (5,268)	$ (5,400)	$ (5,535)	$ (5,673)	$ (5,815)	$ (5,960)	$ (6,109)	$ (6,262)
Total Cost of Operations ($)	$ (30,082)	$ (30,834)	$ (31,605)	$ (32,395)	$ (33,205)	$ (34,035)	$ (34,886)	$ (35,758)	$ (36,652)	$ (37,568)
Operating Income	$ 418,249	$ 417,497	$ 416,726	$ 415,936	$ 415,126	$ 414,296	$ 413,445	$ 412,573	$ 411,679	$ 410,763
Debt Service										
Principal	$ (66,401)	$ (70,386)	$ (74,609)	$ (79,085)	$ (83,830)	$ (88,860)	$ (94,192)	$ (99,843)	$ (105,834)	$ (112,184)
Interest	$ (314,975)	$ (310,991)	$ (306,768)	$ (302,291)	$ (297,546)	$ (292,516)	$ (287,185)	$ (281,533)	$ (275,542)	$ (269,192)
Total Debt Service ($)	$ (381,376)	$ (381,376)	$ (381,376)	$ (381,376)	$ (381,376)	$ (381,376)	$ (381,376)	$ (381,376)	$ (381,376)	$ (381,376)
Project Revenues	$ 36,873	$ 36,121	$ 35,350	$ 34,560	$ 33,750	$ 32,920	$ 32,069	$ 31,197	$ 30,303	$ 29,386
Cash Flow for IRR Calculation	$ (4,831,331)	$ 417,497	$ 416,726	$ 415,936	$ 415,126	$ 414,296	$ 413,445	$ 412,573	$ 411,679	$ 410,763
Cumulative Repayment	$ (4,728,057)	$ (4,621,550)	$ (4,511,592)	$ (4,397,947)	$ (4,280,367)	$ (4,158,587)	$ (4,032,326)	$ (3,901,286)	$ (3,765,150)	$ (3,623,579)
Present Value of Cash Flow	$ 36,873	$ 34,076	$ 31,461	$ 29,017	$ 26,733	$ 24,600	$ 22,607	$ 20,748	$ 19,012	$ 17,394
Debt Service Coverage	1.10	1.09	1.09	1.09	1.09	1.09	1.08	1.08	1.08	1.08
Payback period										

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sales										
Generating Capacity (MW)	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
Energy (MWH)	3,638	3,638	3,638	3,638	3,638	3,638	3,638	3,638	3,638	3,638
Energy Price ($/MWH)	$ 123.23	$ 123.23	$ 123.23	$ 123.23	$ 123.23	$ 123.23	$ 123.23	$ 123.23	$ 123.23	$ 123.23
Energy Sales Revenue ($)	$ 448,331	$ 448,331	$ 448,331	$ 448,331	$ 448,331	$ 448,331	$ 448,331	$ 448,331	$ 448,331	$ 448,331
Cost of Operations										
Operations & Maintenance	$ (8,395)	$ (8,605)	$ (8,820)	$ (9,040)	$ (9,266)	$ (9,498)	$ (9,735)	$ (9,979)	$ (10,228)	$ (10,484)
Administration & Insurance	$ (15,207)	$ (15,588)	$ (15,977)	$ (16,377)	$ (16,786)	$ (17,206)	$ (17,636)	$ (18,077)	$ (18,529)	$ (18,992)
Repair and Replacement	$ (8,487)	$ (8,699)	$ (8,917)	$ (9,140)	$ (9,368)	$ (9,602)	$ (9,842)	$ (10,088)	$ (10,341)	$ (10,599)
Contingency	$ (6,418)	$ (6,579)	$ (6,743)	$ (6,912)	$ (7,085)	$ (7,262)	$ (7,443)	$ (7,629)	$ (7,820)	$ (8,016)
Total Cost of Operations ($)	$ (38,508)	$ (39,470)	$ (40,457)	$ (41,468)	$ (42,505)	$ (43,568)	$ (44,657)	$ (45,773)	$ (46,918)	$ (48,091)
Operating Income	$ 409,824	$ 408,861	$ 407,874	$ 406,863	$ 405,826	$ 404,763	$ 403,674	$ 402,558	$ 401,413	$ 400,240
Debt Service										
Principal	$ (118,915)	$ (126,050)	$ (133,613)	$ (141,630)	$ (150,127)	$ (159,135)	$ (168,683)	$ (178,804)	$ (189,532)	$ (200,904)
Interest	$ (262,461)	$ (255,326)	$ (247,763)	$ (239,747)	$ (231,249)	$ (222,241)	$ (212,693)	$ (202,572)	$ (191,844)	$ (180,472)
Total Debt Service ($)	$ (381,376)	$ (381,376)	$ (381,376)	$ (381,376)	$ (381,376)	$ (381,376)	$ (381,376)	$ (381,376)	$ (381,376)	$ (381,376)
Project Revenues	$ 28,447	$ 27,485	$ 26,498	$ 25,486	$ 24,450	$ 23,387	$ 22,298	$ 21,181	$ 20,037	$ 18,864
Cash Flow for IRR Calculation	$ 409,824	$ 408,861	$ 407,874	$ 406,863	$ 405,826	$ 404,763	$ 403,674	$ 402,558	$ 401,413	$ 400,240
Cumulative Repayment	$ (3,476,217)	$ (3,322,683)	$ (3,162,572)	$ (2,995,456)	$ (2,820,879)	$ (2,638,357)	$ (2,447,376)	$ (2,247,391)	$ (2,037,821)	$ (1,818,053)
Present Value of Cash Flow	$ 15,885	$ 14,479	$ 13,169	$ 11,949	$ 10,814	$ 9,759	$ 8,777	$ 7,866	$ 7,020	$ 6,235
Debt Service Coverage	1.07	1.07	1.07	1.07	1.06	1.06	1.06	1.06	1.05	1.05
Payback period										

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
TOD Factors													
Super-Peak	1.090	1.090	1.130	1.130	1.130	2.010	2.010	2.010	2.010	1.090	1.090	1.090	
Shoulder	0.960	0.960	0.860	0.860	0.860	1.140	1.140	1.140	1.140	0.960	0.960	0.960	
Night	0.780	0.780	0.630	0.630	0.630	0.720	0.720	0.720	0.720	0.780	0.780	0.780	
TOD Prices													
Super-Peak	$ 127.86	$ 127.86	$ 132.55	$ 132.55	$ 132.55	$ 235.77	$ 235.77	$ 235.77	$ 235.77	$ 127.86	$ 127.86	$ 127.86	$ 1,980.02
Shoulder	$ 112.61	$ 112.61	$ 100.88	$ 100.88	$ 100.88	$ 133.72	$ 133.72	$ 133.72	$ 133.72	$ 112.61	$ 112.61	$ 112.61	$ 1,400.56
Night	$ 91.49	$ 91.49	$ 73.90	$ 73.90	$ 73.90	$ 84.46	$ 84.46	$ 84.46	$ 84.46	$ 91.49	$ 91.49	$ 91.49	$ 1,016.99
TOD Generation													
Super-Peak	46.7	42.1	46.7	45.1	110.9	107.3	110.9	110.9	107.3	46.7	45.1	46.7	866.2
Shoulder	84.0	75.8	84.0	81.3	199.6	193.1	199.6	199.6	193.1	84.0	81.3	84.0	1,559.2
Night	65.3	59.0	65.3	63.2	155.2	150.2	155.2	155.2	150.2	65.3	63.2	65.3	1,212.7
TOTAL	195.9	177.0	195.9	189.6	465.6	450.6	465.6	465.6	450.6	195.9	189.6	195.9	3,638.1
Revenue													
Super-Peak	$ 5,965	$ 5,387	$ 6,184	$ 5,984	$ 14,695	$ 25,296	$ 26,139	$ 26,139	$ 25,296	$ 5,965	$ 5,772	$ 5,965	$ 158,788
Shoulder	$ 9,456	$ 8,541	$ 8,471	$ 8,198	$ 20,131	$ 25,825	$ 26,686	$ 26,686	$ 25,825	$ 9,456	$ 9,151	$ 9,456	$ 187,880
Night	$ 5,976	$ 5,397	$ 4,826	$ 4,671	$ 11,470	$ 12,686	$ 13,109	$ 13,109	$ 12,686	$ 5,976	$ 5,783	$ 5,976	$ 101,663
TOTAL	$ 21,396	$ 19,326	$ 19,481	$ 18,853	$ 46,297	$ 63,807	$ 65,934	$ 65,934	$ 63,807	$ 21,396	$ 20,706	$ 21,396	$ 448,331
Weighted Average Price	$ 109.20	$ 109.20	$ 99.43	$ 99.43	$ 99.43	$ 141.60	$ 141.60	$ 141.60	$ 141.60	$ 109.20	$ 109.20	$ 109.20	$ 123.23

Source: PG&E Advice Letter 3410-E. January 27, 2009

	Length of Contract		
Start Year	10	15	20
2010	$ 101.75	$ 107.48	$ 113.90
2011	$ 104.00	$ 110.46	$ 117.30
2012	$ 106.98	$ 114.05	$ 121.26
2013	$ 109.98	$ 117.76	$ 125.27
2014	$ 112.78	$ 121.22	$ 128.97
2015	$ 116.05	$ 125.03	$ 132.90
2016	$ 119.71	$ 129.15	$ 137.06
2017	$ 123.67	$ 133.52	$ 141.44
2018	$ 128.02	$ 138.14	$ 146.03
2019	$ 132.71	$ 142.98	$ 150.80
2020	$ 137.76	$ 147.97	$ 155.78

Source: PG&E Advice Letter 3410-E. January 27, 2009

B2.7 Sly Park Dam

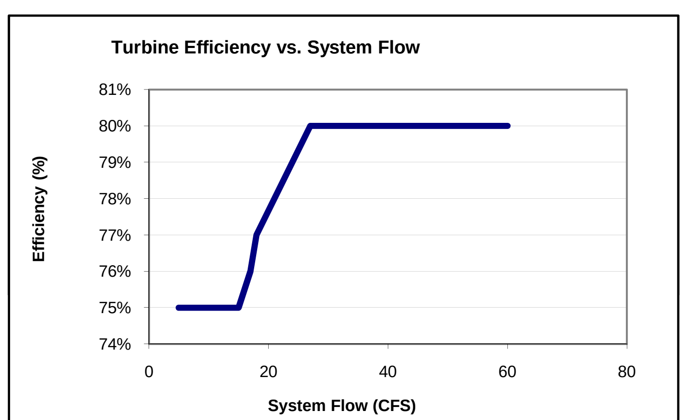
	Total	*Super Peak*							*Shoulder Peak*													
		Weekday							*Weekday*							*Weekend*						
	System Flow (cfs)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)
Jan	14	11.9	170	11.9	170	95	75%	12.3	15.0	220	15.0	220	95	75%	15.5	15.0	180	15.0	180	95	75%	12.4
Feb	15	12.75	170	12.8	170	95	75%	11.9	16.1	210	16.1	210	95	75%	15.0	16.1	170	16.1	170	95	75%	12.0
Mar	15	15.9	230	15.9	230	95	75%	16.5	15.8	230	15.8	230	95	75%	16.3	15.8	180	15.8	180	95	75%	13.1
Apr	18	19.08	270	19.1	270	95	77%	19.7	18.9	270	18.9	270	95	77%	19.5	18.9	210	18.9	210	95	77%	15.6
May	43	45.58	670	45.6	670	95	80%	50.4	45.2	660	45.2	660	95	80%	49.9	45.2	530	45.2	530	95	80%	39.9
Jun	51	52.53	740	52.5	740	95	80%	56.2	52.5	740	52.5	740	95	80%	56.2	51.0	580	51.0	580	95	80%	43.7
Jul	27	27.81	410	27.8	410	95	80%	30.8	27.8	410	27.8	410	95	80%	30.8	27.0	320	27.0	320	95	80%	23.9
Aug	55	56.65	830	56.7	830	95	80%	62.6	56.7	830	56.7	830	95	80%	62.6	55.0	640	55.0	640	95	80%	48.7
Sep	52	53.56	760	53.6	760	95	80%	57.3	53.6	760	53.6	760	95	80%	57.3	52.0	590	52.0	590	95	80%	44.5
Oct	48	57.6	840	57.6	840	95	80%	63.7	46.1	670	46.1	670	95	80%	51.0	46.1	540	46.1	540	95	80%	40.8
Nov	27	32.4	460	32.4	460	95	80%	34.7	25.9	370	25.9	370	95	80%	27.7	25.9	290	25.9	290	95	80%	22.2
Dec	17	14.45	210	14.5	210	95	76%	15.2	18.2	270	18.2	270	95	76%	19.1	18.2	210	18.2	210	95	76%	15.3
Total =	32	33.4	5,760	33.4	5,760	-	-	**430.0**	33	5,640	32.6	5,640	-	-	**420.0**	32	4,440	32.2	4,440	-	-	**330.0**

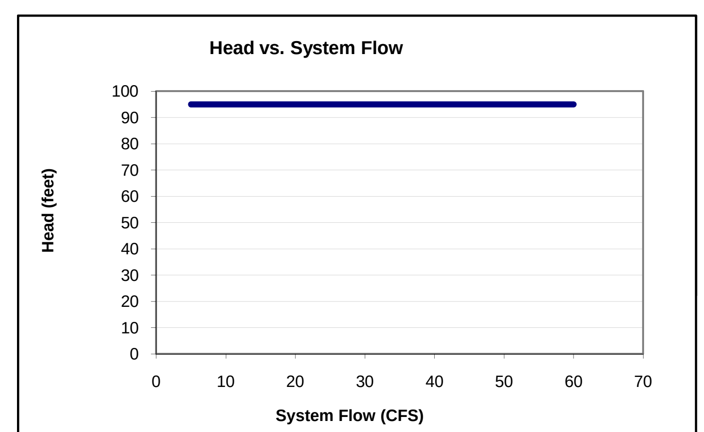
	Total	*Night*																
		Weekday							*Weekend*									
	System Flow (cfs)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	2011-30 Generation* (mWh)	2011-40 Generation* (mWh)	2008 Generation* (mWh)
Jan	14	15.1	220	15.1	220	95	75%	15.7	15.1	90	15.1	90	95	75%	6.3	66	68	62
Feb	15	16.2	210	16.2	210	95	75%	15.2	16.2	90	16.2	90	95	75%	6.1	64	66	60
Mar	15	13.4	200	13.4	200	95	75%	13.8	13.4	80	13.4	80	95	75%	5.5	69	71	65
Apr	18	16.0	230	16.0	230	95	77%	16.5	16.0	90	16.0	90	95	77%	6.6	83	85	78
May	43	38.3	560	38.3	560	95	80%	42.3	38.3	220	38.3	220	95	80%	16.9	212	218	200
Jun	51	47.9	680	47.9	680	95	80%	51.3	51.0	290	51.0	290	95	80%	21.8	244	250	229
Jul	27	25.4	370	25.4	370	95	80%	28.1	27.0	160	27.0	160	95	80%	11.9	134	137	125
Aug	55	51.7	760	51.7	760	95	80%	57.2	55.0	320	55.0	320	95	80%	24.3	272	279	255
Sep	52	48.9	690	48.9	690	95	80%	52.3	52.0	290	52.0	290	95	80%	22.3	249	255	234
Oct	48	40.3	590	40.3	590	95	80%	44.6	40.3	240	40.3	240	95	80%	17.8	232	238	218
Nov	27	22.7	320	22.7	320	95	80%	24.3	22.7	130	22.7	130	95	80%	9.7	126	130	119
Dec	17	18.4	270	18.4	270	95	76%	19.3	18.4	110	18.4	110	95	76%	7.7	82	84	77
Total =	32	30	5,100	29.5	5,100	-	-	**380.0**	30	2,110	30.4	2,110	-	-	**160.0**	**1,830**	**1,880**	**1,720**

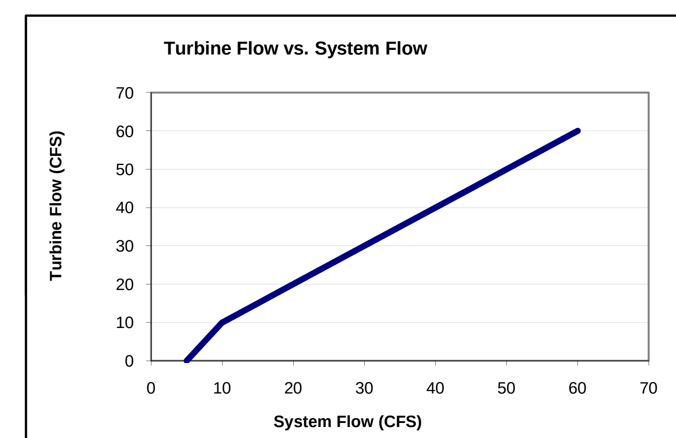
* Assumed at 97% of flow available for generation.

Efficiency

System Flow (cfs)	Turbine Flow (cfs)	Head (ft)	Eff (%)
5	0	95	75%
10	10	95	75%
14	14	95	75%
15	15	95	75%
17	17	95	76%
18	18	95	77%
27	27	95	80%
43	43	95	80%
48	48	95	80%
51	51	95	80%
52	52	95	80%
55	55	95	80%
60	60	95	80%







B2.7 Sly Park Dam

Capital Cost	$ 2,571,000	400	Plant Size (kW)	5.04%	IRR
First Year Annual O&M Costs	$ 7,411	1,833	Avg. Annual Gen (MWh)	$ 121,711	NPV
First Year Annual A&I Costs	$ 5,940	$ 117.30	Baseline Market Price Referent ($/MWh)	27	Payback Period (Years)
First Year Annual Repair & Replace Costs	$ 5,655	2011	Initial Year of Operation	52%	Capacity Factor
First Year Annual Contingency Costs	$ 3,801	30	Term of Debt (Years)	1.01	Minimum Annual Debt Service Coverage
Annual Costs Inflation Rate	2.50%	20	Length of Initial Contract (Years)	$ 124.36	Average Price Received ($/MWh)
Cost of Debt	6.00%		Project Physical Life (Years)	$ 1,402	Capital Cost per Avg Annual Generation ($/MWh)
Discount Rate	6.00%	1.50%	Finance Fee		
Term of CREBs/QECBs (if applicable)		70.00%	CREBs/QECB Subsidy		

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Sales										
Generating Capacity (MW)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
Energy (MWH)	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833
Energy Price ($/MWH)	$ 124.36	$ 124.36	$ 124.36	$ 124.36	$ 124.36	$ 124.36	$ 124.36	$ 124.36	$ 124.36	$ 124.36
Energy Sales Revenue ($)	$ 227,978	$ 227,978	$ 227,978	$ 227,978	$ 227,978	$ 227,978	$ 227,978	$ 227,978	$ 227,978	$ 227,978
Cost of Operations										
Operations & Maintenance	$ (7,411)	$ (7,596)	$ (7,786)	$ (7,981)	$ (8,180)	$ (8,385)	$ (8,594)	$ (8,809)	$ (9,030)	$ (9,255)
Administration & Insurance	$ (5,940)	$ (6,089)	$ (6,241)	$ (6,397)	$ (6,557)	$ (6,721)	$ (6,889)	$ (7,061)	$ (7,237)	$ (7,418)
Repair and Replacement	$ (5,655)	$ (5,796)	$ (5,941)	$ (6,090)	$ (6,242)	$ (6,398)	$ (6,558)	$ (6,722)	$ (6,890)	$ (7,062)
Contingency	$ (3,801)	$ (3,896)	$ (3,993)	$ (4,093)	$ (4,196)	$ (4,300)	$ (4,408)	$ (4,518)	$ (4,631)	$ (4,747)
Total Cost of Operations ($)	$ (22,807)	$ (23,377)	$ (23,962)	$ (24,561)	$ (25,175)	$ (25,804)	$ (26,449)	$ (27,110)	$ (27,788)	$ (28,483)
Operating Income	$ 205,171	$ 204,601	$ 204,017	$ 203,418	$ 202,804	$ 202,174	$ 201,529	$ 200,868	$ 200,190	$ 199,496
Debt Service										
Principal	$ (33,008)	$ (34,989)	$ (37,088)	$ (39,313)	$ (41,672)	$ (44,172)	$ (46,823)	$ (49,632)	$ (52,610)	$ (55,767)
Interest	$ (156,574)	$ (154,593)	$ (152,494)	$ (150,269)	$ (147,910)	$ (145,410)	$ (142,759)	$ (139,950)	$ (136,972)	$ (133,815)
CREB/QECB Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Debt Service ($)	$ (189,582)	$ (189,582)	$ (189,582)	$ (189,582)	$ (189,582)	$ (189,582)	$ (189,582)	$ (189,582)	$ (189,582)	$ (189,582)
Project Revenues	$ 15,589	$ 15,019	$ 14,435	$ 13,836	$ 13,222	$ 12,592	$ 11,947	$ 11,286	$ 10,608	$ 9,914
Cash Flow for IRR Calculation	$ (2,404,394)	$ 204,601	$ 204,017	$ 203,418	$ 202,804	$ 202,174	$ 201,529	$ 200,868	$ 200,190	$ 199,496
Cumulative Repayment	$ (2,355,796)	$ (2,305,788)	$ (2,254,265)	$ (2,201,116)	$ (2,146,222)	$ (2,089,458)	$ (2,030,688)	$ (1,969,769)	$ (1,906,551)	$ (1,840,871)
Present Value of Cash Flow	$ 15,589	$ 14,169	$ 12,847	$ 11,617	$ 10,473	$ 9,410	$ 8,422	$ 7,506	$ 6,656	$ 5,868
Debt Service Coverage	1.08	1.08	1.08	1.07	1.07	1.07	1.06	1.06	1.06	1.05
Payback period										

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sales										
Generating Capacity (MW)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
Energy (MWH)	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833
Energy Price ($/MWH)	$ 124.36	$ 124.36	$ 124.36	$ 124.36	$ 124.36	$ 124.36	$ 124.36	$ 124.36	$ 124.36	$ 124.36
Energy Sales Revenue ($)	$ 227,978	$ 227,978	$ 227,978	$ 227,978	$ 227,978	$ 227,978	$ 227,978	$ 227,978	$ 227,978	$ 227,978
Cost of Operations										
Operations & Maintenance	$ (9,487)	$ (9,724)	$ (9,967)	$ (10,216)	$ (10,472)	$ (10,733)	$ (11,002)	$ (11,277)	$ (11,559)	$ (11,848)
Administration & Insurance	$ (7,604)	$ (7,794)	$ (7,989)	$ (8,188)	$ (8,393)	$ (8,603)	$ (8,818)	$ (9,038)	$ (9,264)	$ (9,496)
Repair and Replacement	$ (7,239)	$ (7,420)	$ (7,605)	$ (7,795)	$ (7,990)	$ (8,190)	$ (8,395)	$ (8,605)	$ (8,820)	$ (9,040)
Contingency	$ (4,866)	$ (4,987)	$ (5,112)	$ (5,240)	$ (5,371)	$ (5,505)	$ (5,643)	$ (5,784)	$ (5,928)	$ (6,076)
Total Cost of Operations ($)	$ (29,195)	$ (29,925)	$ (30,673)	$ (31,440)	$ (32,226)	$ (33,031)	$ (33,857)	$ (34,704)	$ (35,571)	$ (36,460)
Operating Income	$ 198,784	$ 198,054	$ 197,306	$ 196,539	$ 195,753	$ 194,947	$ 194,121	$ 193,275	$ 192,407	$ 191,518
Debt Service										
Principal	$ (59,113)	$ (62,659)	$ (66,419)	$ (70,404)	$ (74,628)	$ (79,106)	$ (83,852)	$ (88,883)	$ (94,216)	$ (99,869)
Interest	$ (130,469)	$ (126,923)	$ (123,163)	$ (119,178)	$ (114,954)	$ (110,476)	$ (105,730)	$ (100,699)	$ (95,366)	$ (89,713)
CREB/QECB Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Debt Service ($)	$ (189,582)	$ (189,582)	$ (189,582)	$ (189,582)	$ (189,582)	$ (189,582)	$ (189,582)	$ (189,582)	$ (189,582)	$ (189,582)
Project Revenues	$ 9,202	$ 8,472	$ 7,724	$ 6,957	$ 6,171	$ 5,365	$ 4,539	$ 3,693	$ 2,825	$ 1,936
Cash Flow for IRR Calculation	$ 198,784	$ 198,054	$ 197,306	$ 196,539	$ 195,753	$ 194,947	$ 194,121	$ 193,275	$ 192,407	$ 191,518
Cumulative Repayment	$ (1,772,557)	$ (1,701,426)	$ (1,627,283)	$ (1,549,922)	$ (1,469,123)	$ (1,384,652)	$ (1,296,261)	$ (1,203,684)	$ (1,106,643)	$ (1,004,837)
Present Value of Cash Flow	$ 5,138	$ 4,463	$ 3,838	$ 3,262	$ 2,729	$ 2,239	$ 1,787	$ 1,371	$ 990	$ 640
Debt Service Coverage	1.05	1.04	1.04	1.04	1.03	1.03	1.02	1.02	1.01	1.01
Payback period										

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
TOD Factors													
Super-Peak	1.090	1.090	1.130	1.130	1.130	2.010	2.010	2.010	2.010	1.090	1.090	1.090	
Shoulder	0.960	0.960	0.860	0.860	0.860	1.140	1.140	1.140	1.140	0.960	0.960	0.960	
Night	0.780	0.780	0.630	0.630	0.630	0.720	0.720	0.720	0.720	0.780	0.780	0.780	
TOD Prices													
Super-Peak	$ 127.86	$ 127.86	$ 132.55	$ 132.55	$ 132.55	$ 235.77	$ 235.77	$ 235.77	$ 235.77	$ 127.86	$ 127.86	$ 127.86	$ 1,980.02
Shoulder	$ 112.61	$ 112.61	$ 100.88	$ 100.88	$ 100.88	$ 133.72	$ 133.72	$ 133.72	$ 133.72	$ 112.61	$ 112.61	$ 112.61	$ 1,400.56
Night	$ 91.49	$ 91.49	$ 73.90	$ 73.90	$ 73.90	$ 84.46	$ 84.46	$ 84.46	$ 84.46	$ 91.49	$ 91.49	$ 91.49	$ 1,016.99
TOD Generation													
Super-Peak	13.1	12.7	17.6	20.9	53.7	59.9	32.7	66.7	61.0	67.8	36.9	16.2	459.2
Shoulder	29.8	28.8	31.3	37.3	95.7	106.3	58.2	118.5	108.4	97.7	53.2	36.6	801.7
Night	23.4	22.6	20.6	24.6	63.1	77.9	42.6	86.8	79.4	66.5	36.2	28.8	572.3
TOTAL	66.3	64.1	69.5	82.8	212.4	244.1	133.5	272.0	248.8	231.9	126.3	81.5	1,833.2
Revenue													
Super-Peak	$ 1,679	$ 1,625	$ 2,326	$ 2,774	$ 7,113	$ 14,112	$ 7,720	$ 15,726	$ 14,388	$ 8,671	$ 4,720	$ 2,066	$ 82,920
Shoulder	$ 3,352	$ 3,243	$ 3,157	$ 3,764	$ 9,653	$ 14,220	$ 7,779	$ 15,846	$ 14,499	$ 10,997	$ 5,986	$ 4,124	$ 96,619
Night	$ 2,138	$ 2,069	$ 1,525	$ 1,818	$ 4,662	$ 6,576	$ 3,598	$ 7,328	$ 6,705	$ 6,081	$ 3,310	$ 2,630	$ 48,439
TOTAL	$ 7,169	$ 6,937	$ 7,008	$ 8,355	$ 21,427	$ 34,908	$ 19,097	$ 38,901	$ 35,592	$ 25,748	$ 14,016	$ 8,821	$ 227,978
Weighted Average Price	$ 108.19	$ 108.19	$ 100.87	$ 100.87	$ 100.87	$ 143.03	$ 143.03	$ 143.03	$ 143.03	$ 111.02	$ 111.02	$ 108.19	$ 124.36

Source: PG&E Advice Letter

Source: PG&E Advice Letter 3410-E. January 27, 2009

	Length of Contract		
Start Year	10	15	20
2010	$ 101.75	$ 107.48	$ 113.90
2011	$ 104.00	$ 110.46	$ 117.30
2012	$ 106.98	$ 114.05	$ 121.26
2013	$ 109.98	$ 117.76	$ 125.27
2014	$ 112.78	$ 121.22	$ 128.97
2015	$ 116.05	$ 125.03	$ 132.90
2016	$ 119.71	$ 129.15	$ 137.06
2017	$ 123.67	$ 133.52	$ 141.44
2018	$ 128.02	$ 138.14	$ 146.03
2019	$ 132.71	$ 142.98	$ 150.80
2020	$ 137.76	$ 147.97	$ 155.78

B2.8 Pleasant Oak Main (Reservoir B)

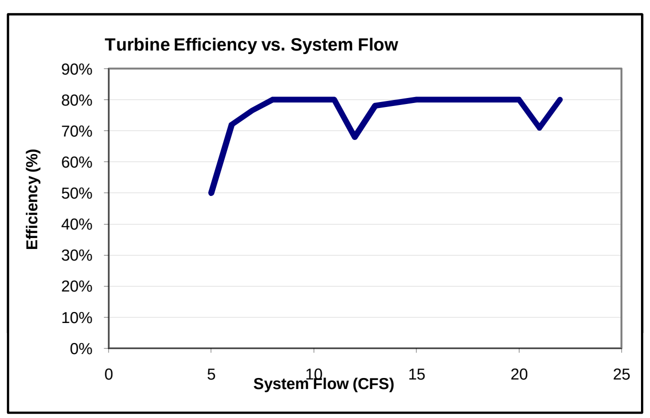
	Total	Super Peak								Shoulder Peak															
		Weekday								Weekday								Weekend							
	System Flow (cfs)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)		System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)		System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	
Jan	6	6.3	90	6.0	90	139	72%	8.7		6.3	90	6.0	90	139	72%	8.7		6.3	70	6	70	139	72%	7.0	
Feb	6	6.4	80	6.0	80	139	72%	7.9		6.4	80	6.0	80	139	72%	7.9		6.4	70	6	60	139	72%	6.3	
Mar	10	10.5	150	9.0	130	133	80%	13.9		10.5	150	9.0	130	133	80%	13.9		10.5	120	9	110	133	80%	11.1	
Apr	15	15.1	210	15.0	210	127	80%	21.5		15.1	210	15.0	210	127	80%	21.5		15.1	170	15	170	127	80%	17.2	
May	19	19.2	280	17.0	250	121	80%	23.9		19.2	280	17.0	250	121	80%	23.9		19.2	220	17	200	121	80%	19.2	
Jun	25	25.2	360	24.0	340	112	80%	30.3		25.5	360	24.0	340	112	80%	30.3		25.7	290	24	270	112	80%	24.2	
Jul	28	27.7	410	24.0	350	104	77%	28.0		28.0	410	24.0	350	104	77%	28.0		28.3	330	24	280	104	77%	22.4	
Aug	27	26.9	390	24.0	350	101	77%	27.2		27.2	400	24.0	350	101	77%	27.2		27.4	320	24	280	101	77%	21.7	
Sep	23	22.9	330	23.0	330	115	80%	29.8		23.2	330	23.2	330	115	80%	30.0		23.4	270	23.4	270	115	80%	24.3	
Oct	13	13.2	190	13.0	190	128	78%	18.9		13	190	13.0	190	128	78%	18.9		13.5	160	13.5	160	128	78%	15.7	
Nov	9	8.6	120	9.0	130	134	80%	13.6		9	130	9.0	130	134	80%	13.6		8.8	100	9	100	134	80%	10.9	
Dec	7	7.1	100	7.0	100	137	77%	10.7		7.1	100	7.0	100	137	77%	10.7		7.1	80	7.1	80	137	77%	8.7	
Total =	16	16	2,710	14.8	2,550	-	-	**230.0**		16	2,730	14.8	2,550	-	-	**230.0**		16	2,200	15	2,050	-	-	**190.0**	

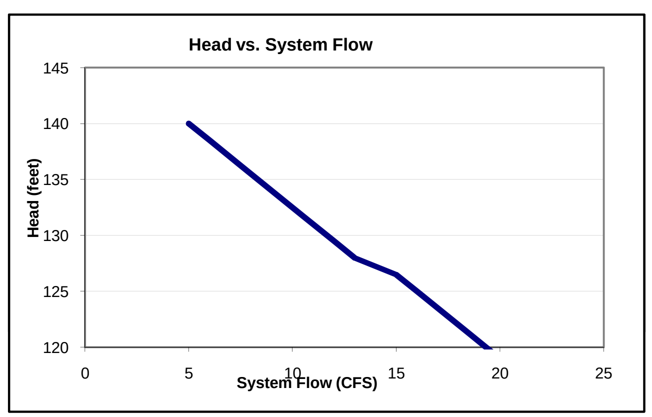
	Total	Night																
		Weekday							Weekend									
	System Flow (cfs)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	2011-30 Generation* (mWh)	2011-40 Generation* (mWh)	2008 Generation* (mWh)
Jan	6	6.3	90	6.0	90	139	72%	8.7	6.3	40	6	40	139	72%	3.5	39	40	37
Feb	6	6.4	80	6.0	80	139	72%	7.9	6.4	30	6	30	139	72%	3.2	35	36	33
Mar	10	10.5	150	9.0	130	133	80%	13.9	10.5	60	9	50	133	80%	5.6	62	64	59
Apr	15	15.1	210	15.0	210	127	80%	21.5	15.1	90	15	90	127	80%	8.6	96	98	90
May	19	19.2	280	17.0	250	121	80%	23.9	19.2	110	17	100	121	80%	9.6	107	110	101
Jun	25	25.5	360	24.0	340	112	80%	30.3	24.7	140	24	140	112	80%	12.1	135	139	127
Jul	28	28.0	410	24.0	350	104	77%	28.0	27.2	160	24	140	104	77%	11.2	125	128	117
Aug	27	27.2	400	24.0	350	101	77%	27.2	26.4	150	24	140	101	77%	10.9	121	125	114
Sep	23	23.2	330	23.2	330	115	80%	30.0	22.5	130	22.5	130	115	80%	11.6	134	137	126
Oct	13	13.5	200	13.5	200	128	78%	19.6	13.0	80	13.0	80	128	78%	7.5	86	88	81
Nov	9	8.8	120	9.0	130	134	80%	13.6	8.5	50	9	50	134	80%	5.4	61	62	57
Dec	7	7.1	100	7.1	100	137	77%	10.9	7.1	40	7.1	40	137	77%	4.3	48	50	45
Total =	16	16	2,730	14.8	2,560	-	-	**240.0**	16	1,080	15	1,030	-	-	**90.0**	**1,050**	**1,080**	**990**

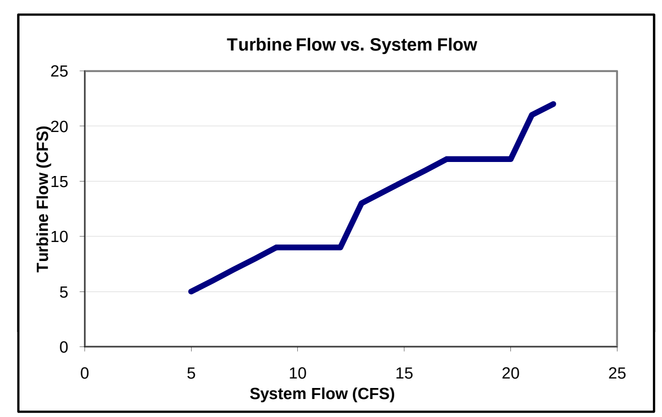
* Assumed at 97% of flow available for generation.

Efficiency

System Flow (cfs)	Turbine Flow (cfs)	Head (ft)	Eff (%)
5	5	140	50%
6	6	139	72%
7	7	137	77%
8	8	136	80%
9	9	134	80%
10	9	133	80%
11	9	131	80%
12	9	130	68%
13	13	128	78%
15	15	127	80%
16	16	125	80%
17	17	124	80%
18	17	122	80%
19	17	121	80%
20	17	119	80%
21	21	118	71%
22	22	116	80%
23	23	115	80%
24	24	113	80%
25	24	112	80%
30	24	95	76%







B2.8 Pleasant Oak Main (Reservoir B Downstream)

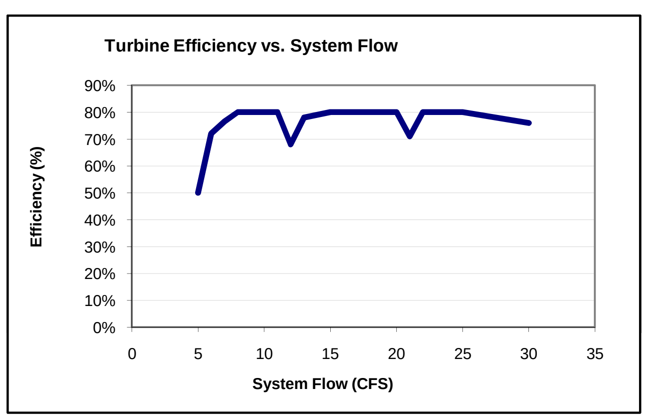
	Total	*Super Peak*							*Shoulder Peak*													
		Weekday							*Weekday*							*Weekend*						
	System Flow (cfs)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)
Jan	6	6.3	90	6.3	90	199	72%	13.1	6.3	90	6.3	90	199	72%	13.1	6.3	70	6.3	70	199	72%	10.5
Feb	6	6.4	80	6.4	80	199	72%	12.0	6.4	80	6.4	80	199	72%	12.0	6.4	70	6.4	70	199	72%	9.6
Mar	10	10.5	150	9.0	130	193	80%	20.2	10.5	150	9.0	130	193	80%	20.2	9.0	110	9.0	110	193	80%	16.2
Apr	15	15.1	210	15.1	210	187	80%	31.8	15.1	210	15.1	210	187	80%	31.8	15.1	170	15.1	170	187	80%	25.4
May	19	19.2	280	17	250	181	80%	35.8	19.2	280	17	250	181	80%	35.8	17	200	17	200	181	80%	28.7
Jun	25	25.2	360	24	340	172	80%	46.5	25.5	360	24	340	172	80%	46.5	24	270	24	270	173	80%	37.4
Jul	28	27.7	410	24	350	168	78%	45.8	28.0	410	24	350	168	78%	45.8	28.3	330	24	280	168	78%	36.6
Aug	27	26.9	390	24	350	167	78%	45.5	27.2	400	24	350	167	78%	45.5	27.4	320	24	280	167	78%	36.4
Sep	23	22.9	330	23	330	175	80%	45.2	23.2	330	23.2	330	175	80%	45.7	23.4	270	23.4	270	175	80%	36.9
Oct	13	13.2	190	13	190	188	78%	28.2	13	190	13	190	188	78%	27.7	13.5	160	13.5	160	188	78%	23.0
Nov	9	8.6	120	9	120	194	80%	18.9	9	130	9	130	194	80%	19.7	8.8	100	8.8	100	194	80%	15.4
Dec	7	7.1	100	7.1	100	197	77%	15.6	7.1	100	7.1	100	197	77%	15.6	7.1	80	7.1	80	197	77%	12.5
Total =	16	16	2,710	15	2,540	-	-	**360.0**	16	2,730	15	2,550	-	-	**360.0**	16	2,150	15	2,060	-	-	**290.0**

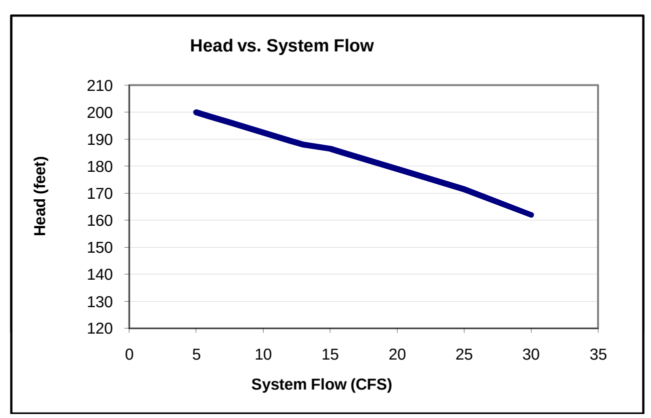
	Total	*Night*																
		Weekday							*Weekend*									
	System Flow (cfs)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	2011-30 Generation* (mWh)	2011-40 Generation* (mWh)	2008 Generation* (mWh)
Jan	6	6.3	90	6.3	90	199	72%	13.1	6.3	40	6.3	40	199	72%	5.3	59	60	55
Feb	6	6.4	80	6.4	80	199	72%	12.0	6.4	30	6.4	30	199	72%	4.8	54	55	50
Mar	10	10.5	150	9.0	130	193	80%	20.2	10.5	60	9.0	50	193	80%	8.1	90	93	85
Apr	15	15.1	210	15.1	210	187	80%	31.8	15.1	90	15.1	90	187	80%	12.7	142	146	133
May	19	19.2	280	17	250	181	80%	35.8	19.2	110	17	100	181	80%	14.3	160	164	150
Jun	25	25.5	360	24	340	172	80%	46.5	24.7	140	24	140	172	80%	18.6	208	214	196
Jul	28	28.0	410	24	350	168	78%	45.8	27.2	160	24	140	167	78%	18.2	205	210	192
Aug	27	27.2	400	24	350	167	78%	45.5	26.4	150	24	140	167	78%	18.2	203	209	191
Sep	23	23.2	330	23.2	330	175	80%	45.7	22.5	130	22.5	130	175	80%	17.7	204	209	191
Oct	13	13.5	200	13.5	200	188	78%	28.8	13.0	80	13.0	80	188	78%	11.1	127	130	119
Nov	9	8.8	120	8.8	120	194	80%	19.3	8.5	50	8.5	50	195	80%	7.4	86	88	81
Dec	7	7.1	100	7.1	100	197	77%	15.6	7.1	40	7.1	40	197	77%	6.2	70	72	66
Total =	16	16	2,730	15	2,550	-	-	**360.0**	16	1,080	15	1,030	-	-	**140.0**	**1,610**	**1,650**	**1,510**

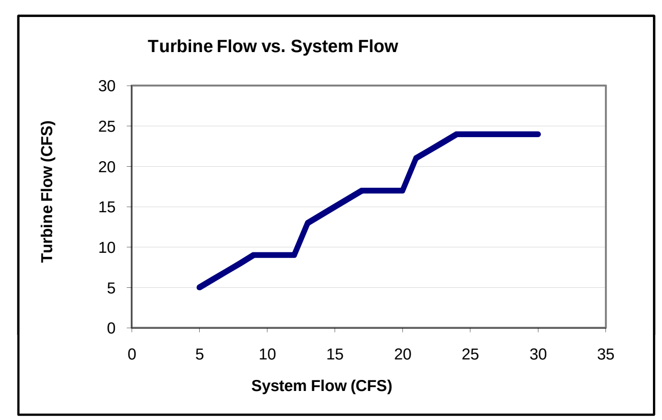
* Assumed at 97% of flow available for generation.

Efficiency

System Flow (cfs)	Turbine Flow (cfs)	Head (ft)	Eff (%)
5	5	200	50%
6	6	199	72%
7	7	197	77%
8	8	196	80%
9	9	194	80%
10	9	193	80%
11	9	191	80%
12	9	190	68%
13	13	188	78%
15	15	187	80%
16	16	185	80%
17	17	184	80%
18	17	182	80%
19	17	181	80%
20	17	179	80%
21	21	178	71%
22	22	176	80%
23	23	175	80%
24	24	173	80%
25	24	172	80%
30	24	162	76%







B2.8 Pleasant Oak Main (Reservoir B)

Capital Cost	$ 3,591,000	450	Plant Size (kW)
First Year Annual O&M Costs	$ 7,058	2,657	Avg. Annual Gen (MWh)
First Year Annual A&I Costs	$ 8,580	$ 117.30	Baseline Market Price Referent ($/MWh)
First Year Annual Repair & Replace Costs	$ 7,833	2011	Initial Year of Operation
First Year Annual Contingency Costs	$ 4,694	30	Term of Debt (Years)
Annual Costs Inflation Rate	2.50%	20	Length of Initial Contract (Years)
Cost of Debt	6.00%	50	Project Physical Life (Years)
Discount Rate	6.00%	1.50%	Finance Fee

5.66%	IRR
$ 319,690	NPV
>20	Payback Period (Years)
67%	Capacity Factor
1.06	Minimum Annual Debt Service Coverage
$ 123.05	Average Price Received ($/MWh)
$ 1,351	Capital Cost per Avg Annual Generation ($/MWh)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Sales										
Generating Capacity (MW)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Energy (MWH)	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657
Energy Price ($/MWH)	$ 123.05	$ 123.05	$ 123.05	$ 123.05	$ 123.05	$ 123.05	$ 123.05	$ 123.05	$ 123.05	$ 123.05
Energy Sales Revenue ($)	$ 326,980	$ 326,980	$ 326,980	$ 326,980	$ 326,980	$ 326,980	$ 326,980	$ 326,980	$ 326,980	$ 326,980
Cost of Operations										
Operations & Maintenance	$ (7,058)	$ (7,234)	$ (7,415)	$ (7,601)	$ (7,791)	$ (7,985)	$ (8,185)	$ (8,390)	$ (8,599)	$ (8,814)
Administration & Insurance	$ (8,580)	$ (8,795)	$ (9,014)	$ (9,240)	$ (9,471)	$ (9,707)	$ (9,950)	$ (10,199)	$ (10,454)	$ (10,715)
Repair and Replacement	$ (7,833)	$ (8,029)	$ (8,230)	$ (8,435)	$ (8,646)	$ (8,862)	$ (9,084)	$ (9,311)	$ (9,544)	$ (9,782)
Contingency	$ (4,694)	$ (4,811)	$ (4,932)	$ (5,055)	$ (5,181)	$ (5,311)	$ (5,444)	$ (5,580)	$ (5,719)	$ (5,862)
Total Cost of Operations ($)	$ (28,165)	$ (28,869)	$ (29,591)	$ (30,331)	$ (31,089)	$ (31,866)	$ (32,663)	$ (33,479)	$ (34,316)	$ (35,174)
Operating Income	$ 298,815	$ 298,111	$ 297,389	$ 296,650	$ 295,891	$ 295,114	$ 294,317	$ 293,501	$ 292,664	$ 291,806
Debt Service										
Principal	$ (46,104)	$ (48,870)	$ (51,802)	$ (54,910)	$ (58,205)	$ (61,697)	$ (65,399)	$ (69,323)	$ (73,482)	$ (77,891)
Interest	$ (218,692)	$ (215,926)	$ (212,993)	$ (209,885)	$ (206,591)	$ (203,098)	$ (199,397)	$ (195,473)	$ (191,313)	$ (186,904)
Total Debt Service ($)	$ (264,795)	$ (264,795)	$ (264,795)	$ (264,795)	$ (264,795)	$ (264,795)	$ (264,795)	$ (264,795)	$ (264,795)	$ (264,795)
Project Revenues	$ 34,020	$ 33,316	$ 32,594	$ 31,854	$ 31,096	$ 30,319	$ 29,522	$ 28,705	$ 27,868	$ 27,010
Cash Flow for IRR Calculation	$ (3,346,050)	$ 298,111	$ 297,389	$ 296,650	$ 295,891	$ 295,114	$ 294,317	$ 293,501	$ 292,664	$ 291,806
Cumulative Repayment	$ (3,265,927)	$ (3,183,741)	$ (3,099,345)	$ (3,012,581)	$ (2,923,281)	$ (2,831,265)	$ (2,736,345)	$ (2,638,317)	$ (2,536,966)	$ (2,432,065)
Present Value of Cash Flow	$ 34,020	$ 31,430	$ 29,008	$ 26,745	$ 24,631	$ 22,656	$ 20,812	$ 19,091	$ 17,485	$ 15,987
Debt Service Coverage	1.13	1.13	1.12	1.12	1.12	1.11	1.11	1.11	1.11	1.10
Payback period										

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sales										
Generating Capacity (MW)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Energy (MWH)	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657
Energy Price ($/MWH)	$ 123.05	$ 123.05	$ 123.05	$ 123.05	$ 123.05	$ 123.05	$ 123.05	$ 123.05	$ 123.05	$ 123.05
Energy Sales Revenue ($)	$ 326,980	$ 326,980	$ 326,980	$ 326,980	$ 326,980	$ 326,980	$ 326,980	$ 326,980	$ 326,980	$ 326,980
Cost of Operations										
Operations & Maintenance	$ (9,035)	$ (9,261)	$ (9,492)	$ (9,730)	$ (9,973)	$ (10,222)	$ (10,478)	$ (10,740)	$ (11,008)	$ (11,283)
Administration & Insurance	$ (10,983)	$ (11,258)	$ (11,539)	$ (11,828)	$ (12,123)	$ (12,426)	$ (12,737)	$ (13,055)	$ (13,382)	$ (13,716)
Repair and Replacement	$ (10,027)	$ (10,278)	$ (10,535)	$ (10,798)	$ (11,068)	$ (11,345)	$ (11,628)	$ (11,919)	$ (12,217)	$ (12,522)
Contingency	$ (6,009)	$ (6,159)	$ (6,313)	$ (6,471)	$ (6,632)	$ (6,798)	$ (6,968)	$ (7,142)	$ (7,321)	$ (7,504)
Total Cost of Operations ($)	$ (36,054)	$ (36,955)	$ (37,879)	$ (38,826)	$ (39,796)	$ (40,791)	$ (41,811)	$ (42,856)	$ (43,928)	$ (45,026)
Operating Income	$ 290,927	$ 290,025	$ 289,101	$ 288,154	$ 287,184	$ 286,189	$ 285,169	$ 284,124	$ 283,052	$ 281,954
Debt Service										
Principal	$ (82,564)	$ (87,518)	$ (92,769)	$ (98,336)	$ (104,236)	$ (110,490)	$ (117,119)	$ (124,146)	$ (131,595)	$ (139,491)
Interest	$ (182,231)	$ (177,277)	$ (172,026)	$ (166,460)	$ (160,560)	$ (154,306)	$ (147,676)	$ (140,649)	$ (133,200)	$ (125,305)
Total Debt Service ($)	$ (264,795)	$ (264,795)	$ (264,795)	$ (264,795)	$ (264,795)	$ (264,795)	$ (264,795)	$ (264,795)	$ (264,795)	$ (264,795)
Project Revenues	$ 26,131	$ 25,230	$ 24,306	$ 23,359	$ 22,388	$ 21,393	$ 20,374	$ 19,328	$ 18,257	$ 17,159
Cash Flow for IRR Calculation	$ 290,927	$ 290,025	$ 289,101	$ 288,154	$ 287,184	$ 286,189	$ 285,169	$ 284,124	$ 283,052	$ 281,954
Cumulative Repayment	$ (2,323,369)	$ (2,210,621)	$ (2,093,546)	$ (1,971,851)	$ (1,845,227)	$ (1,713,344)	$ (1,575,851)	$ (1,432,376)	$ (1,282,524)	$ (1,125,875)
Present Value of Cash Flow	$ 14,591	$ 13,291	$ 12,079	$ 10,952	$ 9,902	$ 8,927	$ 8,020	$ 7,178	$ 6,396	$ 5,671
Debt Service Coverage	1.10	1.10	1.09	1.09	1.08	1.08	1.08	1.07	1.07	1.06
Payback period										

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
TOD Factors													
Super-Peak	1.090	1.090	1.130	1.130	1.130	2.010	2.010	2.010	2.010	1.090	1.090	1.090	
Shoulder	0.960	0.960	0.860	0.860	0.860	1.140	1.140	1.140	1.140	0.960	0.960	0.960	
Night	0.780	0.780	0.630	0.630	0.630	0.720	0.720	0.720	0.720	0.780	0.780	0.780	
TOD Prices													
Super-Peak	$ 127.86	$ 127.86	$ 132.55	$ 132.55	$ 132.55	$ 235.77	$ 235.77	$ 235.77	$ 235.77	$ 127.86	$ 127.86	$ 127.86	$ 1,980.02
Shoulder	$ 112.61	$ 112.61	$ 100.88	$ 100.88	$ 100.88	$ 133.72	$ 133.72	$ 133.72	$ 133.72	$ 112.61	$ 112.61	$ 112.61	$ 1,400.56
Night	$ 91.49	$ 91.49	$ 73.90	$ 73.90	$ 73.90	$ 84.46	$ 84.46	$ 84.46	$ 84.46	$ 91.49	$ 91.49	$ 91.49	$ 1,016.99
TOD Generation													
Super-Peak	23.3	21.2	36.4	56.7	63.6	81.7	78.5	77.3	79.9	50.2	34.6	28.1	631.4
Shoulder	41.9	38.1	65.5	102.0	114.5	147.4	141.3	139.2	145.7	90.9	63.4	50.6	1,140.5
Night	32.6	29.7	50.9	79.3	89.1	114.4	109.8	108.3	111.9	71.3	48.7	39.4	885.4
TOTAL	97.8	89.0	152.7	238.0	267.2	343.6	329.6	324.9	337.5	212.4	146.7	118.1	2,657.3
Revenue													
Super-Peak	$ 2,977	$ 2,709	$ 4,820	$ 7,511	$ 8,434	$ 19,274	$ 18,507	$ 18,236	$ 18,833	$ 6,414	$ 4,421	$ 3,588	$ 115,723
Shoulder	$ 4,719	$ 4,294	$ 6,603	$ 10,290	$ 11,554	$ 19,708	$ 18,894	$ 18,617	$ 19,485	$ 10,232	$ 7,138	$ 5,698	$ 137,231
Night	$ 2,982	$ 2,714	$ 3,762	$ 5,863	$ 6,583	$ 9,666	$ 9,271	$ 9,145	$ 9,449	$ 6,527	$ 4,455	$ 3,609	$ 74,026
TOTAL	$ 10,679	$ 9,716	$ 15,184	$ 23,664	$ 26,570	$ 48,648	$ 46,672	$ 45,999	$ 47,766	$ 23,173	$ 16,014	$ 12,895	$ 326,980
Weighted Average Price	$ 109.20	$ 109.20	$ 99.43	$ 99.43	$ 99.43	$ 141.59	$ 141.62	$ 141.60	$ 141.54	$ 109.12	$ 109.19	$ 109.18	$ 123.05

Source: PG&E Advice Letter 3410-E. January 27, 2009

	Length of Contract		
Start Year	10	15	20
2010	$ 101.75	$ 107.48	$ 113.90
2011	$ 104.00	$ 110.46	$ 117.30
2012	$ 106.98	$ 114.05	$ 121.26
2013	$ 109.98	$ 117.76	$ 125.27
2014	$ 112.78	$ 121.22	$ 128.97
2015	$ 116.05	$ 125.03	$ 132.90
2016	$ 119.71	$ 129.15	$ 137.06
2017	$ 123.67	$ 133.52	$ 141.44
2018	$ 128.02	$ 138.14	$ 146.03
2019	$ 132.71	$ 142.98	$ 150.80
2020	$ 137.76	$ 147.97	$ 155.78

Source: PG&E Advice Letter 3410-E. January 27, 2009

B2.9 Pleasant Oak Main PRS 5 (Reservoir 7)

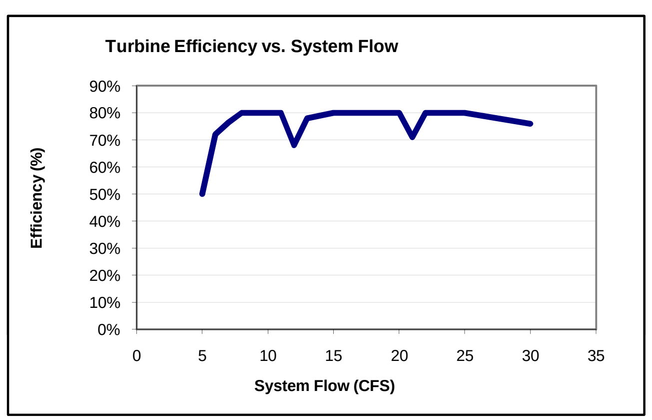
	Total	Super Peak								Shoulder Peak															
		Weekday								Weekday								Weekend							
	System Flow (cfs)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)		System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)		System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	
Jan	6	5.7	80	6	90	340	72%	21.4		5.7	80	6	90	340	72%	21.4		5.7	70	6	70	340	72%	17.1	
Feb	6	5.9	80	6	80	340	72%	19.3		5.9	80	6	80	340	72%	19.3		5.9	60	6	60	340	72%	15.4	
Mar	8	8.4	120	8	120	336	80%	31.3		8.4	120	8	120	336	80%	31.3		8.4	100	8	90	336	80%	25.0	
Apr	12	12.1	170	10	140	323	68%	30.9		12.1	170	10	140	323	68%	30.9		12.1	140	10	110	323	68%	24.7	
May	17	16.9	250	17	250	302	80%	59.8		16.9	250	17	250	302	80%	59.8		16.9	200	17	200	302	80%	47.8	
Jun	22	22.1	310	22	310	271	80%	67.2		22.3	320	22.3	320	271	80%	68.0		22.5	260	22.5	260	271	80%	55.0	
Jul	24	24.3	360	24	350	258	80%	72.1		24.5	360	24.0	350	258	80%	72.1		24.7	290	24	280	258	80%	57.7	
Aug	24	23.5	340	24	350	258	80%	72.1		23.8	350	24.0	350	258	80%	72.1		24.0	280	24	280	258	80%	57.7	
Sep	21	20.6	290	21	300	277	71%	58.2		20.8	290	20.8	290	277	71%	57.7		21.0	240	21.0	240	277	71%	46.6	
Oct	12	12.0	180	10	150	323	68%	32.0		13	190	10	150	323	68%	32.0		12.3	140	12.3	140	323	68%	31.4	
Nov	8	7.8	110	8	110	336	80%	30.3		9	130	8	110	336	80%	30.3		7.9	90	7.9	90	336	80%	24.0	
Dec	6	6.4	90	6	90	340	72%	21.4		6.0	90	6	90	340	72%	21.4		6.0	70	6.0	70	340	72%	17.1	
Total =	14	14	2,380	14	2,340	-	-	**520.0**		14	2,430	14	2,340	-	-	**520.0**		14	1,940	14	1,890	-	-	**420.0**	

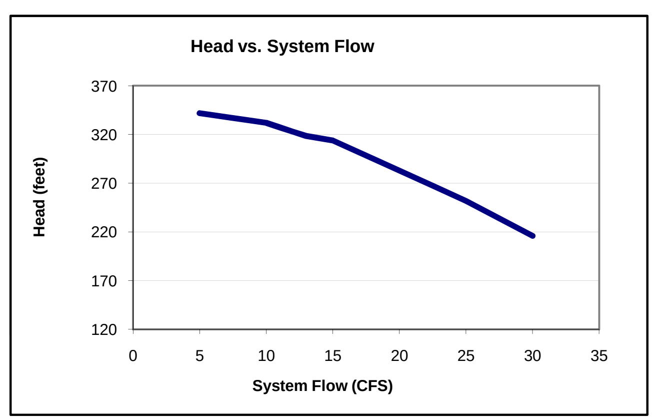
	Total	Night																	
		Weekday							Weekend										
	System Flow (cfs)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	Generation* (mWh)	2011-30 Generation* (mWh)	2011-40 Generation* (mWh)	2008 Generation* (mWh)	
Jan	6	5.7	80	6	90	340	72%	21.4	5.7	30	6	40	340	72%	8.5	96	98	90	
Feb	6	5.9	80	6	80	340	72%	19.3	5.9	30	6	30	340	72%	7.7	86	89	81	
Mar	8	8.4	120	8	120	336	80%	31.3	8.4	50	8	50	336	80%	12.5	140	144	131	
Apr	12	12.1	170	10	140	323	68%	30.9	12.1	70	10	60	323	68%	12.4	138	142	130	
May	17	16.9	250	17	250	302	80%	59.8	16.9	100	17	100	302	80%	23.9	267	274	251	
Jun	22	22.3	320	22.3	320	271	80%	68.0	21.6	120	21.6	120	271	80%	26.4	303	311	285	
Jul	24	24.5	360	24	350	258	80%	72.1	23.8	140	23.8	140	258	80%	28.6	322	330	302	
Aug	24	23.8	350	24	350	258	80%	72.1	23.1	140	23.1	140	258	80%	27.7	321	329	302	
Sep	21	20.8	290	20.8	290	277	71%	57.7	20.2	110	20.2	110	277	71%	22.4	258	265	242	
Oct	12	12.3	180	12.3	180	323	68%	39.2	11.8	70	11.8	70	323	68%	15.1	159	163	150	
Nov	8	7.9	110	7.9	110	336	80%	29.9	7.6	40	7.6	40	336	80%	11.5	134	138	126	
Dec	6	6.4	90	6.0	90	340	72%	21.4	6.4	40	6.0	40	340	72%	8.5	96	98	90	
Total =	14	14	2,400	14	2,370	-	-	**520.0**	14	940	13	940	-	-	**210.0**	**2,320**	**2,380**	**2,180**	

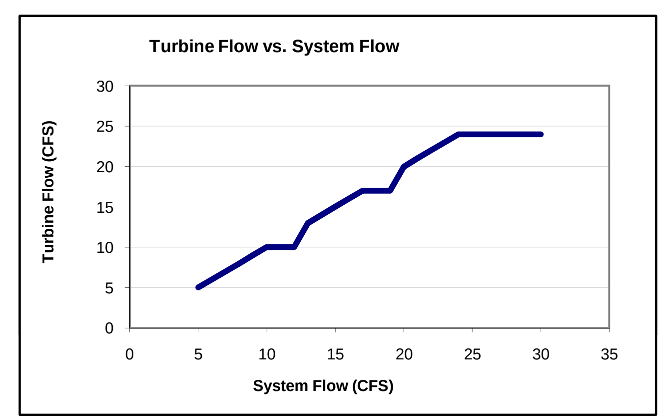
* Assumed at 97% of flow available for generation.

Efficiency

System Flow (cfs)	Turbine Flow (cfs)	Head (ft)	Eff (%)
5	5	342	50%
6	6	340	72%
7	7	338	77%
8	8	336	80%
9	9	334	80%
10	10	332	80%
11	10	328	80%
12	10	323	68%
13	13	319	78%
15	15	314	80%
16	16	308	80%
17	17	302	80%
18	17	295	80%
19	17	289	80%
20	20	283	80%
21	21	277	71%
22	22	271	80%
23	23	264	80%
24	24	258	80%
25	24	252	80%
30	24	216	76%







B2.9 Pleasant Oak Main PRS 5 (Reservoir 7)

Capital Cost	$ 1,523,000	510	Plant Size (kW)
First Year Annual O&M Costs	$ 7,058	2,321	Avg. Annual Gen (MWh)
First Year Annual A&I Costs	$ 7,590	$ 117.30	Baseline Market Price Referent ($/MWh)
First Year Annual Repair & Replace Costs	$ 3,360	2011	Initial Year of Operation
First Year Annual Contingency Costs	$ 3,602	30	Term of Debt (Years)
Annual Costs Inflation Rate	2.50%	20	Length of Initial Contract (Years)
Cost of Debt	6.00%	50	Project Physical Life (Years)
Discount Rate	6.00%	1.50%	Finance Fee

19.82%	IRR
$ 1,702,726	NPV
7	Payback Period (Years)
52%	Capacity Factor
2.25	Minimum Annual Debt Service Coverage
$ 123.71	Average Price Received ($/MWh)
$ 656	Capital Cost per Avg Annual Generation ($/MWh)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Sales										
Generating Capacity (MW)	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Energy (MWH)	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321
Energy Price ($/MWH)	$ 123.71	$ 123.71	$ 123.71	$ 123.71	$ 123.71	$ 123.71	$ 123.71	$ 123.71	$ 123.71	$ 123.71
Energy Sales Revenue ($)	$ 287,082	$ 287,082	$ 287,082	$ 287,082	$ 287,082	$ 287,082	$ 287,082	$ 287,082	$ 287,082	$ 287,082
Cost of Operations										
Operations & Maintenance	$ (7,058)	$ (7,234)	$ (7,415)	$ (7,601)	$ (7,791)	$ (7,985)	$ (8,185)	$ (8,390)	$ (8,599)	$ (8,814)
Administration & Insurance	$ (7,590)	$ (7,780)	$ (7,974)	$ (8,174)	$ (8,378)	$ (8,587)	$ (8,802)	$ (9,022)	$ (9,248)	$ (9,479)
Repair and Replacement	$ (3,360)	$ (3,444)	$ (3,530)	$ (3,618)	$ (3,709)	$ (3,802)	$ (3,897)	$ (3,994)	$ (4,094)	$ (4,196)
Contingency	$ (3,602)	$ (3,692)	$ (3,784)	$ (3,879)	$ (3,976)	$ (4,075)	$ (4,177)	$ (4,282)	$ (4,389)	$ (4,498)
Total Cost of Operations ($)	$ (21,610)	$ (22,150)	$ (22,704)	$ (23,272)	$ (23,853)	$ (24,450)	$ (25,061)	$ (25,687)	$ (26,330)	$ (26,988)
Operating Income	$ 265,472	$ 264,932	$ 264,378	$ 263,811	$ 263,229	$ 262,633	$ 262,021	$ 261,395	$ 260,753	$ 260,094
Debt Service										
Principal	$ (19,553)	$ (20,726)	$ (21,970)	$ (23,288)	$ (24,686)	$ (26,167)	$ (27,737)	$ (29,401)	$ (31,165)	$ (33,035)
Interest	$ (92,751)	$ (91,578)	$ (90,334)	$ (89,016)	$ (87,618)	$ (86,137)	$ (84,567)	$ (82,903)	$ (81,139)	$ (79,269)
Total Debt Service ($)	$ (112,304)	$ (112,304)	$ (112,304)	$ (112,304)	$ (112,304)	$ (112,304)	$ (112,304)	$ (112,304)	$ (112,304)	$ (112,304)
Project Revenues	$ 153,168	$ 152,628	$ 152,074	$ 151,507	$ 150,925	$ 150,329	$ 149,717	$ 149,091	$ 148,449	$ 147,790
Cash Flow for IRR Calculation	$ (1,280,373)	$ 264,932	$ 264,378	$ 263,811	$ 263,229	$ 262,633	$ 262,021	$ 261,395	$ 260,753	$ 260,094
Cumulative Repayment	$ (1,107,651)	$ (934,297)	$ (760,252)	$ (585,457)	$ (409,847)	$ (233,352)	$ (55,898)	$ 122,594	$ 302,207	$ 483,033
Present Value of Cash Flow	$ 153,168	$ 143,989	$ 135,346	$ 127,208	$ 119,547	$ 112,334	$ 105,545	$ 99,154	$ 93,138	$ 87,477
Debt Service Coverage	2.36	2.36	2.35	2.35	2.34	2.34	2.33	2.33	2.32	2.32
Payback period								7	8	9

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sales										
Generating Capacity (MW)	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Energy (MWH)	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321
Energy Price ($/MWH)	$ 123.71	$ 123.71	$ 123.71	$ 123.71	$ 123.71	$ 123.71	$ 123.71	$ 123.71	$ 123.71	$ 123.71
Energy Sales Revenue ($)	$ 287,082	$ 287,082	$ 287,082	$ 287,082	$ 287,082	$ 287,082	$ 287,082	$ 287,082	$ 287,082	$ 287,082
Cost of Operations										
Operations & Maintenance	$ (9,035)	$ (9,261)	$ (9,492)	$ (9,730)	$ (9,973)	$ (10,222)	$ (10,478)	$ (10,740)	$ (11,008)	$ (11,283)
Administration & Insurance	$ (9,716)	$ (9,959)	$ (10,208)	$ (10,463)	$ (10,724)	$ (10,993)	$ (11,267)	$ (11,549)	$ (11,838)	$ (12,134)
Repair and Replacement	$ (4,301)	$ (4,409)	$ (4,519)	$ (4,632)	$ (4,748)	$ (4,866)	$ (4,988)	$ (5,113)	$ (5,240)	$ (5,371)
Contingency	$ (4,611)	$ (4,726)	$ (4,844)	$ (4,965)	$ (5,090)	$ (5,217)	$ (5,347)	$ (5,481)	$ (5,618)	$ (5,758)
Total Cost of Operations ($)	$ (27,663)	$ (28,354)	$ (29,063)	$ (29,790)	$ (30,534)	$ (31,298)	$ (32,080)	$ (32,882)	$ (33,704)	$ (34,547)
Operating Income	$ 259,420	$ 258,728	$ 258,019	$ 257,293	$ 256,548	$ 255,785	$ 255,002	$ 254,200	$ 253,378	$ 252,535
Debt Service										
Principal	$ (35,017)	$ (37,118)	$ (39,345)	$ (41,706)	$ (44,208)	$ (46,861)	$ (49,672)	$ (52,652)	$ (55,812)	$ (59,160)
Interest	$ (77,287)	$ (75,186)	$ (72,959)	$ (70,598)	$ (68,096)	$ (65,443)	$ (62,632)	$ (59,651)	$ (56,492)	$ (53,144)
Total Debt Service ($)	$ (112,304)	$ (112,304)	$ (112,304)	$ (112,304)	$ (112,304)	$ (112,304)	$ (112,304)	$ (112,304)	$ (112,304)	$ (112,304)
Project Revenues	$ 147,116	$ 146,424	$ 145,715	$ 144,989	$ 144,244	$ 143,481	$ 142,698	$ 141,896	$ 141,074	$ 140,231
Cash Flow for IRR Calculation	$ 259,420	$ 258,728	$ 258,019	$ 257,293	$ 256,548	$ 255,785	$ 255,002	$ 254,200	$ 253,378	$ 252,535
Cumulative Repayment	$ 665,165	$ 848,707	$ 1,033,767	$ 1,220,462	$ 1,408,914	$ 1,599,255	$ 1,791,625	$ 1,986,174	$ 2,183,059	$ 2,382,451
Present Value of Cash Flow	$ 82,149	$ 77,134	$ 72,416	$ 67,976	$ 63,799	$ 59,869	$ 56,173	$ 52,695	$ 49,424	$ 46,348
Debt Service Coverage	2.31	2.30	2.30	2.29	2.28	2.28	2.27	2.26	2.26	2.25
Payback period	10	11	12	13	14	15	16	17	18	19

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
TOD Factors													
Super-Peak	1.090	1.090	1.130	1.130	1.130	2.010	2.010	2.010	2.010	1.090	1.090	1.090	
Shoulder	0.960	0.960	0.860	0.860	0.860	1.140	1.140	1.140	1.140	0.960	0.960	0.960	
Night	0.780	0.780	0.630	0.630	0.630	0.720	0.720	0.720	0.720	0.780	0.780	0.780	
TOD Prices													
Super-Peak	$ 127.86	$ 127.86	$ 132.55	$ 132.55	$ 132.55	$ 235.77	$ 235.77	$ 235.77	$ 235.77	$ 127.86	$ 127.86	$ 127.86	$ 1,980.02
Shoulder	$ 112.61	$ 112.61	$ 100.88	$ 100.88	$ 100.88	$ 133.72	$ 133.72	$ 133.72	$ 133.72	$ 112.61	$ 112.61	$ 112.61	$ 1,400.56
Night	$ 91.49	$ 91.49	$ 73.90	$ 73.90	$ 73.90	$ 84.46	$ 84.46	$ 84.46	$ 84.46	$ 91.49	$ 91.49	$ 91.49	$ 1,016.99
TOD Generation													
Super-Peak	22.8	20.6	33.3	32.9	63.6	71.5	76.7	76.7	61.9	34.0	32.2	22.8	549.1
Shoulder	41.0	37.0	60.0	59.3	114.5	131.0	138.1	138.1	111.0	67.4	57.7	41.0	996.1
Night	31.9	28.8	46.6	46.1	89.1	100.5	107.1	106.3	85.2	57.8	44.1	31.9	775.4
TOTAL	95.6	86.3	139.9	138.3	267.2	303.0	322.0	321.1	258.1	159.3	134.1	95.6	2,320.6
Revenue													
Super-Peak	$ 2,909	$ 2,628	$ 4,416	$ 4,365	$ 8,434	$ 16,859	$ 18,093	$ 18,093	$ 14,599	$ 4,350	$ 4,122	$ 2,909	$ 101,777
Shoulder	$ 4,612	$ 4,166	$ 6,049	$ 5,979	$ 11,554	$ 17,512	$ 18,471	$ 18,471	$ 14,842	$ 7,594	$ 6,503	$ 4,612	$ 120,366
Night	$ 2,915	$ 2,633	$ 3,447	$ 3,407	$ 6,583	$ 8,492	$ 9,049	$ 8,974	$ 7,197	$ 5,290	$ 4,039	$ 2,915	$ 64,939
TOTAL	$ 10,436	$ 9,426	$ 13,911	$ 13,751	$ 26,570	$ 42,863	$ 45,613	$ 45,538	$ 36,638	$ 17,235	$ 14,664	$ 10,436	$ 287,082
Weighted Average Price	$ 109.20	$ 109.20	$ 99.43	$ 99.43	$ 99.43	$ 141.46	$ 141.65	$ 141.81	$ 141.94	$ 108.20	$ 109.32	$ 109.20	$ 123.71

Source: PG&E Advice Letter 3410-E. January 27, 2009

	Length of Contract		
Start Year	10	15	20
2010	$ 101.75	$ 107.48	$ 113.90
2011	$ 104.00	$ 110.46	$ 117.30
2012	$ 106.98	$ 114.05	$ 121.26
2013	$ 109.98	$ 117.76	$ 125.27
2014	$ 112.78	$ 121.22	$ 128.97
2015	$ 116.05	$ 125.03	$ 132.90
2016	$ 119.71	$ 129.15	$ 137.06
2017	$ 123.67	$ 133.52	$ 141.44
2018	$ 128.02	$ 138.14	$ 146.03
2019	$ 132.71	$ 142.98	$ 150.80
2020	$ 137.76	$ 147.97	$ 155.78

Source: PG&E Advice Letter 3410-E. January 27, 2009

B2.10 Diamond Springs Main PRS 1 (Reservoir 8)

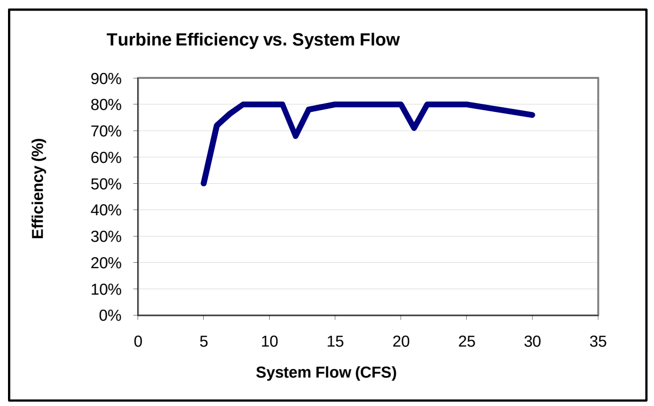
	System Flow (cfs)	System Flow (af)	Turbine Flow (cfs)	Turbine Flow (af)	Head (feet)	Eff (%)	2011-30 Generation* (mWh)	2011-40 Generation* (mWh)	2008 Generation* (mWh)
Jan	6	400	6	400	136	72%	38	39	36
Feb	6	300	6	300	136	72%	35	35	32
Mar	8	500	8	500	132	80%	55	56	52
Apr	12	700	9	500	122	68%	47	48	44
May	17	1,000	17	1,000	107	80%	95	97	89
Jun	22	1,300	17	1,000	86	80%	74	76	69
Jul	24	1,500	17	1,000	77	80%	68	70	64
Aug	24	1,400	17	1,000	77	80%	68	70	64
Sep	21	1,200	17	1,000	90	71%	68	70	64
Oct	12	700	9	600	122	68%	49	50	46
Nov	8	500	8	500	132	80%	53	55	50
Dec	6	400	6	400	136	72%	38	39	36
Total =	14	9,900	11	8,200	-	-	**690**	**710**	**650**

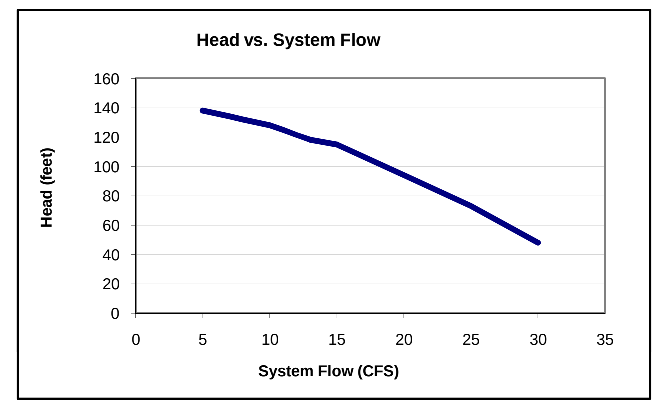
* Assumed at 97% of flow available for generation.

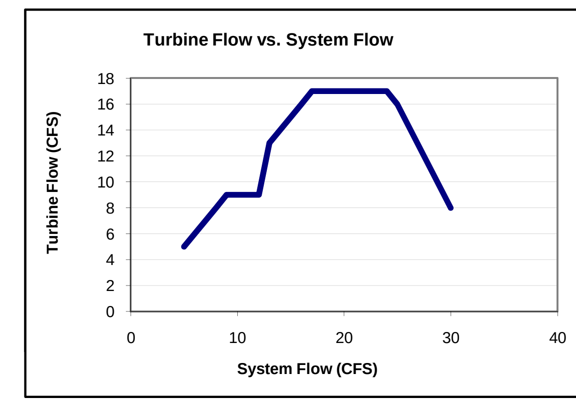
Efficiency

DSM PRS1

System Flow (cfs)	Turbine Flow (cfs)	Head (ft)	Eff (%)
5	5	138	50%
6	6	136	72%
7	7	134	77%
8	8	132	80%
9	9	130	80%
10	9	128	80%
11	9	125	80%
12	9	122	68%
13	13	118	78%
15	15	115	80%
16	16	111	80%
17	17	107	80%
18	17	102	80%
19	17	98	80%
20	17	94	80%
21	17	90	71%
22	17	86	80%
23	17	81	80%
24	17	77	80%
25	16	73	80%
30	8	48	76%







Maintain 25 cfs on POM PRS3

B2.10 Diamond Springs Main PRS1

Capital Cost	$ 1,082,000	140	Plant Size (kW)
First Year Annual O&M Costs	$ 7,058	688	Avg. Annual Gen (MWh)
First Year Annual A&I Costs	$ 2,277	$ 117.30	Baseline Market Price Referent ($/MWh)
First Year Annual Repair & Replace Costs	$ 2,376	2011	Initial Year of Operation
First Year Annual Contingency Costs	$ 2,342	30	Term of Debt (Years)
Annual Costs Inflation Rate	2.50%	20	Length of Initial Contract (Years)
Cost of Debt	6.00%	50	Project Physical Life (Years)
Discount Rate	6.00%	1.50%	Finance Fee

1.76%	IRR
$ (168,717)	NPV
>20	Payback Period (Years)
56%	Capacity Factor
0.75	Minimum Annual Debt Service Coverage
$ 119.52	Average Price Received ($/MWh)
$ 1,573	Capital Cost per Avg Annual Generation ($/MWh)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sales																				
Generating Capacity (MW)	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Energy (MWH)	688	688	688	688	688	688	688	688	688	688	688	688	688	688	688	688	688	688	688	688
Energy Price ($/MWH)	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52	$ 119.52
Energy Sales Revenue ($)	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196	$ 82,196
Cost of Operations																				
Operations & Maintenance	$ (7,058)	$ (7,234)	$ (7,415)	$ (7,601)	$ (7,791)	$ (7,985)	$ (8,185)	$ (8,390)	$ (8,599)	$ (8,814)	$ (9,035)	$ (9,261)	$ (9,492)	$ (9,730)	$ (9,973)	$ (10,222)	$ (10,478)	$ (10,740)	$ (11,008)	$ (11,283)
Administration & Insurance	$ (2,277)	$ (2,334)	$ (2,392)	$ (2,452)	$ (2,513)	$ (2,576)	$ (2,641)	$ (2,707)	$ (2,774)	$ (2,844)	$ (2,915)	$ (2,988)	$ (3,062)	$ (3,139)	$ (3,217)	$ (3,298)	$ (3,380)	$ (3,465)	$ (3,551)	$ (3,640)
Repair and Replacement	$ (2,376)	$ (2,435)	$ (2,496)	$ (2,559)	$ (2,623)	$ (2,688)	$ (2,755)	$ (2,824)	$ (2,895)	$ (2,967)	$ (3,041)	$ (3,118)	$ (3,195)	$ (3,275)	$ (3,357)	$ (3,441)	$ (3,527)	$ (3,615)	$ (3,706)	$ (3,798)
Contingency	$ (2,342)	$ (2,401)	$ (2,461)	$ (2,522)	$ (2,585)	$ (2,650)	$ (2,716)	$ (2,784)	$ (2,853)	$ (2,925)	$ (2,998)	$ (3,073)	$ (3,150)	$ (3,228)	$ (3,309)	$ (3,392)	$ (3,477)	$ (3,564)	$ (3,653)	$ (3,744)
Total Cost of Operations ($)	$ (14,053)	$ (14,404)	$ (14,764)	$ (15,134)	$ (15,512)	$ (15,900)	$ (16,297)	$ (16,705)	$ (17,122)	$ (17,550)	$ (17,989)	$ (18,439)	$ (18,900)	$ (19,372)	$ (19,857)	$ (20,353)	$ (20,862)	$ (21,383)	$ (21,918)	$ (22,466)
Operating Income	$ 68,143	$ 67,792	$ 67,432	$ 67,062	$ 66,684	$ 66,296	$ 65,899	$ 65,491	$ 65,074	$ 64,646	$ 64,207	$ 63,757	$ 63,296	$ 62,824	$ 62,340	$ 61,843	$ 61,334	$ 60,813	$ 60,278	$ 59,730
Debt Service																				
Principal	$ (13,891)	$ (14,725)	$ (15,608)	$ (16,545)	$ (17,538)	$ (18,590)	$ (19,705)	$ (20,888)	$ (22,141)	$ (23,469)	$ (24,877)	$ (26,370)	$ (27,952)	$ (29,629)	$ (31,407)	$ (33,292)	$ (35,289)	$ (37,406)	$ (39,651)	$ (42,030)
Interest	$ (65,894)	$ (65,060)	$ (64,177)	$ (63,240)	$ (62,248)	$ (61,195)	$ (60,080)	$ (58,898)	$ (57,644)	$ (56,316)	$ (54,908)	$ (53,415)	$ (51,833)	$ (50,156)	$ (48,378)	$ (46,494)	$ (44,496)	$ (42,379)	$ (40,134)	$ (37,755)
Total Debt Service ($)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)	$ (79,785)
Project Revenues	$ (11,642)	$ (11,994)	$ (12,354)	$ (12,723)	$ (13,101)	$ (13,489)	$ (13,886)	$ (14,294)	$ (14,711)	$ (15,139)	$ (15,578)	$ (16,028)	$ (16,489)	$ (16,961)	$ (17,446)	$ (17,942)	$ (18,451)	$ (18,972)	$ (19,507)	$ (20,055)
Cash Flow for IRR Calculation	$ (1,030,087)	$ 67,792	$ 67,432	$ 67,062	$ 66,684	$ 66,296	$ 65,899	$ 65,491	$ 65,074	$ 64,646	$ 64,207	$ 63,757	$ 63,296	$ 62,824	$ 62,340	$ 61,843	$ 61,334	$ 60,813	$ 60,278	$ 59,730
Cumulative Repayment	$ (1,027,838)	$ (1,025,106)	$ (1,021,852)	$ (1,018,029)	$ (1,013,593)	$ (1,008,492)	$ (1,002,673)	$ (996,079)	$ (988,650)	$ (980,320)	$ (971,021)	$ (960,679)	$ (949,215)	$ (936,547)	$ (922,586)	$ (907,237)	$ (890,398)	$ (871,964)	$ (851,821)	$ (829,846)
Present Value of Cash Flow	$ (11,642)	$ (11,315)	$ (10,995)	$ (10,682)	$ (10,377)	$ (10,080)	$ (9,789)	$ (9,506)	$ (9,230)	$ (8,961)	$ (8,699)	$ (8,443)	$ (8,194)	$ (7,952)	$ (7,716)	$ (7,487)	$ (7,263)	$ (7,046)	$ (6,834)	$ (6,628)
Debt Service Coverage	0.85	0.85	0.85	0.84	0.84	0.83	0.83	0.82	0.82	0.81	0.80	0.80	0.79	0.79	0.78	0.78	0.77	0.76	0.76	0.75
Payback period																				

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
TOD Factors													
Super-Peak	1.090	1.090	1.130	1.130	1.130	2.010	2.010	2.010	2.010	1.090	1.090	1.090	
Shoulder	0.960	0.960	0.860	0.860	0.860	1.140	1.140	1.140	1.140	0.960	0.960	0.960	
Night	0.780	0.780	0.630	0.630	0.630	0.720	0.720	0.720	0.720	0.780	0.780	0.780	
TOD Prices													
Super-Peak	$ 127.86	$ 127.86	$ 132.55	$ 132.55	$ 132.55	$ 235.77	$ 235.77	$ 235.77	$ 235.77	$ 127.86	$ 127.86	$ 127.86	$ 1,980.02
Shoulder	$ 112.61	$ 112.61	$ 100.88	$ 100.88	$ 100.88	$ 133.72	$ 133.72	$ 133.72	$ 133.72	$ 112.61	$ 112.61	$ 112.61	$ 1,400.56
Night	$ 91.49	$ 91.49	$ 73.90	$ 73.90	$ 73.90	$ 84.46	$ 84.46	$ 84.46	$ 84.46	$ 91.49	$ 91.49	$ 91.49	$ 1,016.99
TOD Generation													
Super-Peak	9.1	8.2	13.1	11.2	22.5	17.5	16.2	16.2	16.3	11.6	12.7	9.1	163.7
Shoulder	16.4	14.8	23.6	20.1	40.6	31.6	29.2	29.2	29.3	20.8	22.8	16.4	294.7
Night	12.7	11.5	18.3	15.7	31.6	24.5	22.7	22.7	22.8	16.2	17.7	12.7	229.2
TOTAL	38.2	34.5	55.0	47.0	94.7	73.6	68.1	68.1	68.4	48.6	53.2	38.2	687.7
Revenue													
Super-Peak	$ 1,164	$ 1,051	$ 1,735	$ 1,484	$ 2,988	$ 4,134	$ 3,825	$ 3,825	$ 3,840	$ 1,479	$ 1,619	$ 1,164	$ 28,307
Shoulder	$ 1,845	$ 1,666	$ 2,376	$ 2,033	$ 4,093	$ 4,221	$ 3,905	$ 3,905	$ 3,920	$ 2,345	$ 2,567	$ 1,845	$ 34,721
Night	$ 1,166	$ 1,053	$ 1,354	$ 1,158	$ 2,332	$ 2,073	$ 1,918	$ 1,918	$ 1,926	$ 1,482	$ 1,622	$ 1,166	$ 19,168
TOTAL	$ 4,174	$ 3,770	$ 5,465	$ 4,674	$ 9,414	$ 10,428	$ 9,648	$ 9,648	$ 9,685	$ 5,305	$ 5,809	$ 4,174	$ 82,196
Weighted Average Price	$ 109.20	$ 109.20	$ 99.43	$ 99.43	$ 99.43	$ 141.60	$ 141.60	$ 141.60	$ 141.60	$ 109.20	$ 109.20	$ 109.20	$ 119.52

Source: PG&E Advice Letter 3410-E. January 27, 2009

	Length of Contract		
Start Year	10	15	20
2010	$ 101.75	$ 107.48	$ 113.90
2011	$ 104.00	$ 110.46	$ 117.30
2012	$ 106.98	$ 114.05	$ 121.26
2013	$ 109.98	$ 117.76	$ 125.27
2014	$ 112.78	$ 121.22	$ 128.97
2015	$ 116.05	$ 125.03	$ 132.90
2016	$ 119.71	$ 129.15	$ 137.06
2017	$ 123.67	$ 133.52	$ 141.44
2018	$ 128.02	$ 138.14	$ 146.03
2019	$ 132.71	$ 142.98	$ 150.80
2020	$ 137.76	$ 147.97	$ 155.78

Source: PG&E Advice Letter 3410-E. January 27, 2009

Environmental Regulatory Permitting and Feed-In Tariff RPS Certification

Environmental Regulatory Permitting and Feed-In Tariff RPS Certification

C1. Overview of the Environmental Regulatory Process and Permits

C2. Permitting Overview

C2.1 Project Proponent and/or CEQA Lead Agency

C2.2 Federal Agency Requirements

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C2.4 Local Agency Requirements

C3. Applying for RPS Certification and Pre-Certification for FIT Projects

Environmental Regulatory Permitting

Introduction

The purpose of this section is to present a general discussion of the key environmental permits and related environmental permitting challenges associated with the development of the hydroelectric development options. Detailed assessments will be required once specific projects have been selected for implementation and agencies have been consulted.

The section begins with a general overview of the various types of permits and approvals typically associated with the development of hydroelectric facilities followed by tables that summarize the likely environmental permitting requirements for each project.

C1. Overview of the Environmental Regulatory Process and Permits

Listed below are the general types of environmental regulatory review processes and permits associated with development of hydroelectric projects. Depending on the selected option, some projects may require all or many of these steps while others may require only a few. The following list is intended to follow the general sequencing and timeline of the primary processes and permits associated with the development of hydroelectric facilities.

- Initiate FERC license process. This may involve a conduit exemption or small hydropower project license exemption (for projects 5 megawatts or less), an amendment to an existing license, or new (minor or major) license. This process will be subject to mandatory terms and conditions set by federal and state fish and wildlife agencies (e.g., U. S. Forest Service Section 4(e) Conditions).
- Project Proponent (e.g., EID, GDPUD, STPUD, or other State Lead Agency) to prepare California Environmental Quality Act (CEQA) documentation.
- Federal Lead Agency (e.g., FERC) to complete required National Environmental Policy Act (NEPA) documentation (e.g., Environmental Assessment (EA) or Environmental Impact Statement) (EIS)).
- The USFS may prepare a Supplemental NEPA EA for FERC License/License Amendment activities on USFS lands.
- State Water Resources Control Board (SWRCB) may issue Clean Water Act Section 401 Water Quality Certification or Waiver with mandatory conditions. The SWRCB may also process and authorize applications for changes in points of diversion or use of existing rights and potential new water rights.
- Potential permits may include: USFS Federal Land Policy and Management Act Consistency Review and Special Use Permit, Nationwide or Individual Permit (U.S. Army Corps of Engineers Clean Water Act, Section 404), Streambed Alteration Agreement (Fish and Game Code, Section 1601), Endangered Species Act Section 7 Consultation (USFWS and NMFS), Section 106 consultation under the National Historic Preservation Act, Regional Water Quality Control Board (RWQCB) to issue Waste Discharge Requirements (WDRs),

National Pollutant Discharge Elimination System (NPDES) Permit, and General Construction Activity Permits based on water quality control plans prepared by Project Proponent.

- Submit application to the California Energy Commission for renewable energy certification. The CPUC concurrence action is required for small hydroelectric projects (less than 30 MW) to qualify as a renewable resource and FIT projects less than 1.5 MW to qualify for “must-take” FIT contracts with investor owned utilities such as PG&E
- Private landowner easment and approved agreements related to use of USFS/private roads and lands.

The relatively large-scale projects (e.g., Alder Creek Dam) would likely require a series of approvals and permits as noted above. However, the smaller projects with a relatively minor project footprint (e.g., Low-High Flow Energy Recovery at PH) may involve only a few of the steps noted above. The following paragraphs provide more detailed descriptions of the agency permitting and approval processes. The construction and operation of hydroelectric facilities may require reviews and approvals from multiple federal and state authorities and also some local and private entities. Each entity and the associated permits that are likely to be required are discussed below.

C2 Permitting Overview

C2.1 Project Proponent and/or CEQA Lead Agency

As a public agency, the project proponent (e.g., EID, GDPUD, or EDCWA) will act as CEQA Lead Agency for complying with CEQA documentation and public review requirements. This may involve preparation of an Environmental Impact Report (EIR), Negative Declaration or Categorical Exemption. The CEQA process will be coordinated with State and local agencies that have permit and other review/approval authority (i.e., responsible agencies) so that CEQA requirements are simultaneously satisfied for the responsible State/local agencies that will issue permits.

There are several approaches that the Project Proponent could follow to satisfy CEQA requirements. The considerations listed below will be important to selecting the best approach:

- Will the project design largely be finalized before initiating the CEQA review process, or will the project proponent consider alternative design/remediation options through the CEQA process?
- Can the environmental impacts be mitigated to below a level of significance, thereby allowing for a Mitigated Negative Declaration (MND) instead of an EIR?
- Are the permitting and other review/approval agencies expected to readily concur with the design and mitigation measures, or will other agencies identify design or other project component alternatives to be evaluated during the CEQA process?

Taking the hydroelectric development options under consideration earlier rather than later and selecting a specific project and determining that all potential environmental impacts can be mitigated will allow the CEQA Lead Agency to complete a shorter duration CEQA MND process. However, if the CEQA Lead Agency has not yet decided on the project design this could lengthen the duration of the CEQA EIR process. In this instance, a combined State/Federal EIR/EA environmental document and review process would likely be most efficient.

C2.2 Federal Agency Requirements

There are several federal agencies that could have applicable permit/review requirements to any development option: FERC, United States Army Corps of Engineers (USACE), United States Fish and Wildlife Service (USFWS), and USFS. The Bureau of Reclamation and the Bureau of Land Management may have jurisdiction as well, depending on the project location. Prior to the commencement of construction, these federal agencies will need to issue permits and approvals, and complete associated public review processes for construction and operational activities. The governing regulations and document requirements of each agency are discussed below.

Compliance with NEPA and the Federal Power Act are potentially the most onerous and time consuming federal environmental regulatory requirements associated with each option, especially for projects that include water storage at undeveloped sites (e.g., Alder Reservoir options).

It is likely that FERC will serve as the lead federal agency to comply with NEPA. The FERC license application process (see below) includes a detailed environmental assessment and agency scoping process. The results of this analysis will guide the NEPA requirements. If the environmental analysis determines that a project is likely to have significant impacts to biological and/or archaeological resources, then the FERC may compile an NEPA Environmental Assessment. However, most projects that meet the criteria for a license exemption have a small project footprint and do not necessarily require a lengthy NEPA document. The FERC NEPA document will be limited to address only those issues of concern as noted in the environmental section of the license application (FERC pers. comm. 2008).

FEDERAL ENERGY REGULATORY COMMISSION: FERC is the clearing house for all non-federal hydroelectric projects in the United States. FERC jurisdiction over hydroelectric power projects is guided by the Federal Power Act (FPA) and as Federal Lead Agency for NEPA.

The FPA authorizes FERC to grant licenses and exemptions for the purpose of "constructing, operating, and maintaining dams, water conduits, reservoirs, power houses, transmission lines for the development, transmission, and utilization of power across, along, from or in any of the streams or other bodies of water over which Congress has jurisdiction". Following is a brief summary of the different types of FERC license processes.

If there is an existing FERC license, this license must be amended to allow construction and operation of the selected option. FERC regulations classify license amendments as either capacity-related amendments or non-capacity-related amendments. Capacity-related amendments include applications for hydropower projects that involve additional generating capacity not previously authorized, and that: (1) would increase the actual or proposed total installed capacity of the project; (2) would result in an increase in the maximum hydraulic capacity of the project of 15 percent or more; AND (3) would result in an increase in the installed nameplate capacity of 2 MW or more (see 18 CFR 4.201(b)). Amendment applications that do not meet the above criteria are classified as non-capacity related amendments.

In general, the information and consultation requirements for non-capacity-related amendment projects are less rigorous than capacity related amendment projects (see 18 CFR 4.38). Nevertheless, an amendment application must include those exhibits that are affected by the proposed project modifications. Also, an amendment must include a review of the draft amendment application by the appropriate resource agencies. The agencies must be allowed a minimum of 60 days to review the draft application, after which the applicant may finalize the amendment application and submit it to FERC. For planning purposes, a 12 to 24 month FERC review process should be assumed, although amendments for non-controversial or projects with minimal environmental impacts may be issued sooner.

In certain cases, hydroelectric projects may qualify for an exemption from FERC licensing. The process of getting an exemption is typically simpler than applying for a new license. Those receiving an exemption are exempt from Part I of the Federal Power Act. However, the exempted project is subject to mandatory terms and conditions set by the federal and state fish and wildlife agencies and by the Commission and do not convey the right of eminent domain.

The Commission issues two types of exemptions:

1) Small hydropower projects, which are 5 MW or less, that will be built at an existing dam, or projects that utilize a natural water feature for head or an existing project that has a capacity of 5 MW or less and proposes to increase capacity, or,
2) Conduit exemption that would be issued for constructing a hydropower project on an existing conduit (for example irrigation canal). Conduit exemptions are authorized for generating capacities 15 MW or less for non-municipal and 40 MW or less for a municipal project. The conduit has to have been constructed primarily for purposes other than power production and be located entirely on non-federal lands.

The majority of the hydroelectric projects identifed in this study would likely qualify for the conduit exemption and/or smalll hydropower license exemption. The Small Alder Project would likley involve an amendment to license.

U. S. ARMY CORPS OF ENGINEERS: USACE may authorize activities under Section 404 of the Clean Water Act (CWA). Section 404 of the CWA requires a permit from the USACE for any discharge of dredge or fill materials, temporary or permanent, into any Waters of the U. S., including wetlands. Dependent upon the extent of the proposed impact, the USACE will authorize activities under either a Nationwide Permit (NWP) or Individual Permit. NWPs were established to allow the USACE to grant general permits for similar categories of discharges that will have only minimal adverse effects. Individual permits are issued for projects that are greater than, or include activities not specified within, the scope and threshold limitations of NWPs. The USACE will review proposed activities with respect to their potential impacts on wetlands, threatened or endangered species under Section 7 of the ESA, and cultural resources and historic properties under Section 106 of the NHPA, prior to issuing a NWP or an Individual Permit. If a permit is required and if there is a potential to disturb any cultural resources, a cultural resources report will be required, which meets the federal standard for documenting cultural resources (different from the CEQA standard).

A NWP may be required for certain options, but not others. Regardless of the selected development option and final design, consulation with USACE will likely be required, but USACE permitting may not be necessary. For example, options that willl include crossing a stream; building near a stream, lake, or wetland; will likely require a NWP (NWP #17 for Hydropower Projects).

U. S. FISH AND WILDLIFE SERVICE*:* A discretionary action by federal agencies requires consultation with the U. S. Fish and Wildlife Service (USFWS). The purpose of the consultation is to determine the potential for protected or other special-status species and associated habitats to occur in the project area, determine the nature and extent of potential adverse impacts to fish and wildlife species, and identify appropriate mitigation measures. Further consultations and possibly additional environmental studies may be required depending on whether there is potential for protected or other special-status species to be affected by the project.

US FOREST SERVICE: The USFS will likely require permits/approvals for options on or affecting National Forest System lands. These include Federal Power Act, land use and right-of-way authorizations. The USFS may identify license (4(e) conditions and 10(a) recommendations) during the FERC license process. The USFS may also issue a Special Use Permit for construction-related activities on USFS lands. Because there is a difference in USFS jurisdiction between lands within the FERC license boundary and lands outside of the license boundary, separate USFS permits and other authorizations will be required. Examples of the types of activities that will require USFS approval outside of the FERC license boundaries include:

- construction/helicopter staging areas,
- stockpile areas,
- equipment hauling and placement on USFS roads,
- helicopter fly zones (including seasonal and geographic restrictions) over USFS lands, and
- Reopening of temporary construction access roads.

The existing FERC license for some projects include several 4(e) conditions that will affect the scope, design, operation, and maintenance of the development options.

C2.3 State Agency Requirements

There are six primary State agencies that will have applicable review and/or permit/approval requirements for most hydroelectric development options: State Water Resources Control Board (SWRCB), Regional Water Quality Control Board, California Department of Fish and Game (CDFG), the State Office of Historic Preservation (as represented by the State Historic Preservation Officer or SHPO, California Energy Commission (CEC) and the California Public Utilities Commission (CPUC) as discussed above). During the CEQA review process, these state agencies will be consulted, and then following completion of CEQA, applications/requests will be submitted for specific permits, approvals, and review processes.

STATE WATER RESOURCES CONTROL BOARD: The EPA delegated the State Water Resources Control Board (SWRCB) Federal authority for the Clean Water Act (CWA) in California. As an example, for Project 184, the SWRCB has been responsible for the issuance of CWA Section 401 Water Quality Certifications (WQC) or Waivers. Section 402 of the CWA and associated National Pollutant Discarge Elimination System (NPDES) Permits have been administered by the Regional Water Quality Control Board as described below.

CWA Section 401 requires that a WQC be obtained or waived before a federal agency issues a permit for an activity that may result in a discharge into state waters. CWA Section 401 WQC therefore is necessary for USACE Individual and NWPs. However, the State of California has pre-certified a number of NWPs for all of California, subject to conditions and notification requirements.

REGIONAL WATER QUALITY CONTROL BOARD: Depending on the development option, RWQCB permits may be required. Some permits fall under Section 402 of the CWA and involve NPDES permits, and others fall under the RWQCB authority over Waste Discharge Requirements that include solid (i.e., tunnel rock) wastes.

Similar to CWA Section 401 authority of the SWRCB, the authority to administer the CWA Section 402 NDPES permit program was delegated to and is held by the RWQCB. NPDES permits provide authorization to discharge pollutants into waters of the United States from point sources.

NPDES General Construction Activity Storm Water Permits may be required for construction, and apply to activities that may result in soil disturbances of at least one acre of total land area, including off-site staging areas or material storage areas. Storm Water Pollution Prevention Plans (SWPPP) are required by the Construction Storm Water Permits.

In addition to the above, and depnding on the qualifications of hazardous substances, the RWQCB may require Spill Prevention and Containment Response Plans for storage, handling, and use of hazardous materials that include fuel, chemicals, and equipment lubricants and coolants.

CALIFORNIA DEPARTMENT OF FISH AND GAME: The crossing or encroachment into a pond or lake or stream, either during construction or as a permanent installation, will require the submittal of a Streambed/Lakebed Alteration Agreement (CDFG Section 1602) for approval by CDFG. The primary concern is generally the changes to stream flows, changes to water quality, and physical (habitat) impacts associated with the project construction and/or operation within the stream or lake zone.

STATE OFFICE OF HISTORIC PRESERVATION: Federal discretionary actions such as those issued by the USACE will be pre-conditioned upon completion of a review under Section 106 of the Federal National Historic Preservation Act of 1966 (NHPA). Typically, the State Historic Preservation Officer (SHPO) is contacted to determine the nature and extent of potential adverse impacts to historic or cultural sites at a construction site.

NHPA Section 106 regulations require that any project take into account the effects on historic properties in the area that are eligible or potentially eligible for listing on the National Register of Historic Places.

CALIFORNIA ENERGY COMMISSION: The Overall Program Guidebook (CEC 2008, Guidebook) describes specific aspects of how the California Energy Commission's Renewable Energy Program is administered and the guidebook outlines terms and definitions. The Guidebook also addresses aspects related to California's Renewables Portfolio Standard (RPS), which has a goal of obtaining 20 percent of the state's electricity from renewable resources by the year 2010. These Guidelines assist interested applicants in applying for Renewable Energy Program funds and RPS Certification. Individuals and entities are eligible for program funding and RPS certification if they satisfy the eligibility requirements specified in the program element guidebooks.

To qualify for funding or RPS certification, eligible individuals and entities must apply to the Commission as specified in the applicable program element guidebook. RPS Certification verifies that an applicant is certified by the Commission as eligible toward meeting the state's Renewables Portfolio Standard pursuant to Public Utilities Code Sections 399.12 and 399.13 and Public Resources Code Section 25741. Section C3 explains the key steps and information required for RPS certification and pre-certification for FIT projects.

CALIFORNIA PUBLIC UTILITIES COMMISSION: AB 1969, approved on September 29, 2006, adds Section 399.20 to the Public Utilities (PU) Code which requires all electrical corporations to file with the CPUC a standard tariff (i.e., FIT) to provide payment for every kilowatt hour (kWh) of renewable energy output produced at an electric generation facility at the market price determined by the CPUC for a period of 10, 15, or 20 years. For purposes of Section 399.20, an eligible generation facility must be an eligible renewable energy resource owned and operated by a public water or wastewater agency that is a retail customer of the electric utility (e.g., PG&E), interconnected and operated in parallel with the utility's transmission and distribution system, and be sized to offset part or all of the electric demand of the public agency.

Section 399.20 limits payment to eligible facilities to a cumulative rated generating capacity of 250 MW statewide. Service will be available upon request on a first-come-first-served basis until the utility meets its proportionate share (i.e., about 105 MW allocated for water and wastewater facilities for PG&E) of the statewide limit.

The RPS Guidebook (CEC 2008) states that to qualify for the FIT program and other renewable energy incentives, an RPS-eligible small hydroelectric facility or conduit hydroelectric facility must not exceed 30 MW and must meet certain other criteria. In addition to a certification or pre-certification application applicants for small hydroelectric facilities or conduit hydroelectric facilities must complete a supplemental application form and provide additional required information. The requirements are described in greater detail below.

OTHER STATE PERMITS: In addition to the permits discussed above, construction activities may require one or more Encroachment Permits from the California Department of Transporation and possibly the California Highway Patrol for traffic controls and signage, special equipment hauling, helicopter overflights, and transport of explosives on Highway 50.

C2.4 Local Agency Requirements

Several environmental reviews, permits and approvals may be required by El Dorado County. The County may conduct a land use consistency review to determine if the project is consistent with zoning and land use planning outlined in the El Dorado County General Plan. Prior to the commencement of construction, consultation with local agencies will be required to determine the building permits, approvals, and associated processes that will be required for construction and operational activities. A preliminary review of permits that may be required from the County includes a Blasting Permit and Emergency Generator Air Quality Permit should construction require blasting or the use of generator. In addition, the County Office of Emergency Services may require that a permit be obtained prior to construction activities involving blasting.

C3. Applying for RPS Certification and Pre-Certification for FIT Projects

Before PG&E or other investor owned utility can purchase renewable energy from a qualified hydroelectric project, the CEC must certify that the project meets Renewable Portfolio Standard as defined by PU Code 399.20. This section summarizes the steps from pre-certification and certification. Pre-certification is advisable prior to submitting a FIT contract to PG&E or other IOU.

- Submit a completed application, along with necessary supporting documentation, to the CEC at the address shown on the form.

- Provisional or “pre-certification” as an eligible renewable resource is available for applicants whose facilities are not yet on-line. Applicants seeking pre-certification must complete Form CEC-RPS-1B, indicate their desire to be pre-certified on their completed CEC-RPS-1B form, and submit all required supplemental information, as described below, to the extent that information is available.

- If the additional required information is not available at the time of precertification because of the facility’s stage of development, then the applicant must explain this in its application and identify the missing information and the date(s) when the information is expected to be available.

- Facilities that are pre-certified must submit a complete and updated certification application (CEC-RPS-1A) with all additional required information and be certified as RPS-eligible before any of its generation may be counted toward satisfying a retail seller’s RPS procurement requirements.

- The Energy Commission will notify applicants in writing of its determination on the application for certification. If the application for certification or pre-certification is approved, the Energy Commission will issue a certificate stating that the facility is certified or pre-certified as eligible for the RPS.

- The certificate will not include an expiration date and will remain in effect for the life of the facility.

- For applicants that must submit additional required information, such as biofuels, hydroelectric, or out-of-state facilities, the Energy Commission must conduct an extensive review of the additional data. Review of these applications will require a minimum of 30 days from when the Energy Commission receives a complete application. The 30-day clock starts on the date a complete application is date-stamped by the Energy Commission as received and the Executive Director makes a determination on any related applications for confidential designation. After completing its review, the Energy Commission will either notify the applicant of its proposed determination or will request additional information from the applicant.

The following instructions apply to applications for hydroelectric facilities. The additional required information described below must be submitted as an attachment to the applicant’s completed CEC-RPS-1A or CEC-RPS-1B form, along with the appropriate supplement form, if applicable.

- An applicant must provide additional information to substantiate its self-certification that a small hydroelectric facility, conduit hydroelectric facility, or incremental generation from efficiency improvements to hydroelectric facilities regardless of overall facility size is eligible for the RPS if the facility:

1) Commenced commercial operations or was repowered on or after January 1, 2006, for small or conduit hydroelectric facilities.
2) Commenced commercial operations before January 1, 2007, for incremental generation from efficiency improvements regardless of facility size.
3) Was added to an existing water conduit on or after January 1, 2006, for conduit hydroelectric facilities.

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- Additional required water-use data and documentation described below must be attached to a completed CEC-RPS-1A (for certification) or CEC-RPS-1B (for precertification) form. These requirements apply to facilities located within California. Applicants possessing a permit or license from the State Water Resources Control Board (SWRCB) must submit a copy of the permit or license as well as the application for the permit or license.

1) Name of the Facility

2) Ownership of the Facility

3) Source Water Description (see RPS Eligibility Commission Guidebook for details)

- The application must identify the source of the water for the hydroelectric project. The source must be characterized as surface, groundwater, or other (for example, recycled water).
- For surface water sources, a map at a scale of 1:24,000 must be provided. The map should also identify the location of the diversion point and all other facilities. In addition, a written description of the location of the diversion should be provided (county and nearest city) as well as the name of the body of water at the point of diversion.

4) Water Rights

- Applicants must clearly establish their right to divert water by submitting all necessary information as well as all appropriate licenses or permits.
- This information must identify the permitted volume, rate, and timing of water diversions, the place of diversion, and beneficial uses. This may be achieved through submittal of the appropriate SWRCB appropriation permit or license, or the Statement of Water Diversion and Use filed with SWRCB.
- For diversions not subject to an appropriation permit or license, a copy of any Statement of Water Diversion and Use filed with SWRCB should be provided.

5) Hydrologic Data

- The applicant must submit appropriation and/or diversion data for the last five years or for the period of operation if the project has been operating less than five years. Information contained in any legally required reports may be used to meet this requirement if sufficient information is included in the report. For other projects, the hydrologic data submitted must be accompanied by a description of how the data is collected. Flow data shall be provided at the frequency set forth in the applicable water appropriation permit; for example, if the permit specifies minimum and maximum flows on a monthly basis that is the level of information necessary to be submitted.

6) Other Permits

- The applicant must submit all other applicable permits, including those permits and exemptions issued by the Federal Energy Regulatory Commission (FERC).

7) Environmental Documentation

- The applicant must submit copies of any permits, agreements, contracts, or other requirements affecting the operation of the facility, especially those that affect the volume, rate, timing, temperature, turbidity, and dissolved oxygen content of the stream water before and after the points of diversion.

8) Capacity

- For small and conduit hydroelectric facilities, the applicant must demonstrate how the project will comply with the 30 MW size limitations under the RPS and not cause an adverse impact on instream beneficial uses or a change in the volume or timing of streamflow. For this purpose, a facility may have an adverse impact on the instream beneficial uses if it causes an adverse change in the chemical, physical, or biological characteristics of water.

Please note that CEC has detailed submission requirements for the items listed above; therefore, it is important to review these requirements in the CEC Renewable Portfolio Standard Eligibility Commission Guidebook (Third Edition) dated January 2008.

Feed-In Tariff Program

Feed-In Tariff Program

- PG&E Electric Schedule E-PWF – Section 399.20 PPA
- Power Purchase Agreement with PG&E
- Resolution E-4214/SVN Appendix B – Utility's 2008 Time of Delivery (TOD) periods and factors
- Difference Between Feed-In Tariffs and other Renewable Programs
- Eligible Renewable Generation and Allocations
- PG&E Advice 3410-E-A – Supplemental Filing for the Modifications to the Tariffs and Standard Contracts for the Purchase of Eligible Renewable Generation from Public Water and Wastewater Facilities and Small Renewable Generators

ELECTRIC SCHEDULE E-PWF
SECTION 399.20 PPA

Sheet 1

APPLICABILITY: This Schedule is optional for customers who meet the definition of an Eligible Public Water Facility or Eligible Public Wastewater Facility and own an Eligible Renewable Energy Resource as defined in the Special Conditions section of this Schedule, with a total effective generation capacity of not more than 1.5 megawatts.

Service under this Schedule is on a first-come-first-served basis and shall be closed to new customers once the combined rated generating capacity of Eligible Renewable Energy Resource within PG&E's service territory reaches 104.603 megawatts, as set forth in D. 07-07-027, effective July 26, 2007.

An electric generation facility must meet the criteria listed in Public Utilities Code section 399.20(b) as follows: (N)

(1) Has an effective capacity of not more than one and one-half megawatts and is located on property owned or under the control of the customer.

(2) Is interconnected and operates in parallel with the electric transmission and distribution grid.

(3) Is strategically located and interconnected to the electric transmission system in a manner that optimizes the deliverability of electricity generated at the facility to load centers.

(4) Is an eligible renewable energy resource, as defined in Section 399.12. (N)

TERRITORY: The entire territory served.

RATES: The customer's otherwise applicable tariff schedule (OAS) shall apply except as follows:

PG&E shall purchase the output produced by an Eligible Renewable Energy Resource at the price and pursuant to the terms set forth in Section 2.4 of the Section 399.20 Power Purchase Agreement at the applicable Market-Price-Referent (MPR) in the table in Section 6 of this Schedule for the date the Eligible Renewable Energy Resource begins actual commercial operation.

1. Required Contract: Section 399.20 Power Purchase Agreement that the customer has submitted to PG&E and that both the customer and PG&E have signed is required prior to receiving service under this Schedule.

2. Participation in other PG&E Programs: As set forth in Decision 07-07-027, customers taking service under this Schedule may not obtain benefits from both this Schedule and the Self-Generation Incentive Program, net energy metering programs, the California Solar Initiative, or other similar programs (T)

(Continued)

ELECTRIC SCHEDULE E-PWF
SECTION 399.20 PPA

SPECIAL CONDITIONS: (cont'd)

3. Definitions: The following definitions are applicable to service provided under this Schedule.

   a. Eligible Public Wastewater Facility - Any facility owned by a state, local, or federal agency and used in the treatment or reclamation of sewage and industrial wastes, and located on property owned or under the control of the public water or wastewater agency. (T)

   b. Eligible Public Water Facility – Any facility owned by a state, local or federal agency that develops, stores, distributes or supplies water and located on property owned or under the control of the public water or wastewater agency.

   c. Eligible Renewable Energy Resource – An electric generating facility as defined in Public Utilities Code Section 399.12 and California Public Resources Code Section 25741, as either code provision may be amended or supplemented from time to time.

   d. Effective Capacity – The capacity of the eligible renewable generator as established by the manufacturer that is available for use either at-site to meet customer load or exported to the grid for sale to PG&E under the Section 399.20 PPA. PG&E will use either the nameplate rating of the eligible renewable generator if no inverter is used, or the inverter rating if the generator is inverter based. (N)

4. Electrical interconnection to support this tariff shall be accomplished using PG&E's Small Generator Interconnection Procedures (SGIP) as filed and approved by the Federal Energy Regulatory Commission (FERC) for distribution and transmission voltage service interconnections, effective August 27, 2006. As part of that electrical interconnection process, the customer and PG&E shall execute a FERC-approved Small Generator Interconnection Agreement (SGIA).

5. Metering Requirements: Seller shall comply with all applicable rules in installing a meter appropriate for deliveries pursuant to the Full Buy/Sell or Excess Sale arrangement selected in paragraph 2.2 of the Section 399.20 Power Purchase Agreement, which can be electronically read daily by: (a) a telephone and modem; (b) an analog or digital phone connection; or (c) an internet portal address for PG&E's Energy Data Services ("EDS"). Seller shall be responsible for procuring and maintaining the communication link to electronically retrieve this metering data.

(Continued)

ELECTRIC SCHEDULE E-PWF
SECTION 399.20 PPA

Sheet 3

SPECIAL CONDTIONS: (cont'd)

6. The Market Price Referent (MPR) is stated in the table below, which the Commission approved in Resolution E-4214, effective December 19, 2008. (T)

Adopted 2008 Market Price Referents (N)
(Nominal - dollars/kWh)

Resource Type	10-Year	15-Year	20-Year
2009 Baseload MPR	0.10043	0.10537	0.11126
2010 Baseload MPR	0.10175	0.10748	0.11390
2011 Baseload MPR	0.10400	0.11046	0.11730
2012 Baseload MPR	0.10698	0.11405	0.12126
2013 Baseload MPR	0.10998	0.11776	0.12527
2014 Baseload MPR	0.11278	0.12122	0.12897
2015 Baseload MPR	0.11605	0.12503	0.13290
2016 Baseload MPR	0.11971	0.12915	0.13706
2017 Baseload MPR	0.12367	0.13352	0.14144
2018 Baseload MPR	0.12802	0.13814	0.14603
2019 Baseload MPR	0.13271	0.14298	0.15080
2020 Baseload MPR	0.13776	0.14797	0.15578

(N)

(Continued)

SECTION 399.20

POWER PURCHASE AGREEMENT

BETWEEN

_______________________________________ AND

PACIFIC GAS AND ELECTRIC COMPANY

PACIFIC GAS AND ELECTRIC COMPANY, a California Corporation ("PG&E" or "Buyer"), and ________________________ ("Seller") hereby enter into this Power Purchase Agreement ("Agreement"). Seller and PG&E are sometimes referred to in this Agreement jointly as "Parties" or individually as "Party." In consideration of the mutual promises and obligations stated in this Agreement and its appendices, the Parties agree as follows:

1. DOCUMENTS INCLUDED; DEFINED TERMS

This Agreement includes the following appendices, which are specifically incorporated herein and made a part of this Agreement.

Appendix A- Definitions

Appendix B- Initial Energy Delivery Date Confirmation Letter

Appendix C- Time of Delivery ("TOD") Periods and Factors

Appendix D- Counterparty Notification Requirements for Outage and Generation Schedule Changes

2. SELLER'S GENERATING FACILITY, PURCHASE PRICES AND PAYMENT

2.1 Facility. This Agreement governs PG&E's purchase of energy and capacity from the electrical generating facility (hereinafter referred to as the "Facility" or "Unit") as described in this Section.

2.1.1 The Facility is located at ________________ in _________ County, California.

2.1.2 The Facility is described as ___________________________.

2.1.3 The Facility's primary fuel is _______ [i.e. biogas, hydro, etc.].

2.1.4 The Facility has a nameplate rating of ___ kilowatts ("kW"), at unity power factor at 60 degrees Fahrenheit at sea level and has a primary voltage level of ____ kilovolts ("kV"). Seller shall not modify the Facility to increase the nameplate rating without the prior written consent of PG&E.

2.1.5 The Facility is connected to the PG&E electric system at _____ kV.

2.1.6 If not already capable of delivering energy on the Execution Date, the Facility's scheduled Commercial Operation Date is ________________.

2.1.7 A description of the Facility, including a summary of its significant components, a drawing showing the general arrangements of the Facility, and a single line diagram illustrating the interconnection of the Facility and loads with PG&E's electric distribution system, is attached and incorporated herein as Appendix E.

2.1.8 The name and address PG&E uses to locate the electric service account(s) and premises used to interconnect the Facility with PG&E's distribution systems is:

____

____

____

____

2.2 Transaction. During the Delivery Term of this Agreement, as provided in Section 2.3, Seller shall sell and deliver, or cause to be delivered, and PG&E shall purchase and receive, or cause to be received, energy produced by and capacity provided from the Facility, up to 1500 kW, at the Delivery Point, as defined pursuant to Section 5.1, pursuant to Seller's election of a (check one) ☐ full buy/sell or ☐ excess sale arrangement as described in paragraphs 2.2.1 and 2.2.2 below. PG&E shall pay Seller the Contract Price, set forth in Section 2.4, in accordance with the terms hereof. In no event shall Seller have the right to procure the energy or capacity from sources other than the Facility for sale or delivery to PG&E under this Agreement or substitute such energy or capacity. PG&E shall have no obligation to receive or purchase energy or capacity from Seller prior to the Initial Energy Delivery Date, as defined in Section 2.3, or after the end of the Delivery Term, as defined in Section 2.3. The Parties agree that the execution and performance of the Parties under this Agreement shall satisfy PG&E's obligations, if any, under the Public Utility Regulatory Policies Act and its implementing regulations, i.e., 18 C.F.R. §§ 292.303.

2.2.1 Full Buy/Sell. Seller agrees to sell to PG&E the Facility's gross output in kilowatt-hours, net of Station Use and transformation and transmission losses to the Delivery Point into the PG&E system, together with all Green Attributes and Resource Adequacy Benefits. Seller shall purchase all energy required to serve the Facility's on-site load, net of station use, from PG&E pursuant to PG&E's applicable retail rate schedule.

2.2.2 Excess Sale. Seller agrees to sell to PG&E the Facility's gross output in kilowatt-hours, net of Station Use and any on-site use by Seller and transformation and transmission losses to the Delivery Point into the PG&E system. Seller agrees to convey to PG&E all Green Attributes and Resource Adequacy Benefits associated with the energy sold to PG&E.

2.3 Delivery Term. The Seller shall deliver the energy and capacity from the Facility to PG&E for a period of (check one) ☐ ten (10), ☐ fifteen (15), or ☐ twenty (20) Contract Years ("Delivery Term"), which shall commence on the first date on which energy is delivered from the Facility to PG&E ("Initial Energy Delivery Date") under this Agreement and continue until the end of the last Contract Year unless terminated by the terms of this Agreement. The Initial Energy Delivery Date shall occur only when all of the following conditions have been satisfied:

(i) the Commercial Operation Date has occurred, if the Facility was not in operation prior to the Execution Date of this Agreement;

(ii) the Facility's status as an Eligible Renewable Energy Resource, is demonstrated by Seller's receipt of certification from the CEC and is registered in WREGIS; and

(iii) as evidence of the Initial Energy Delivery Date, the Parties shall execute and exchange the "Initial Energy Delivery Date Confirmation Letter" attached hereto as Appendix B on the Initial Energy Delivery Date.

2.4 Contract Price. Once both Parties have executed this Agreement PG&E shall pay Seller for each megawatt-hour ("MWh") of energy and associated capacity delivered to PG&E during each Contract Year for the Delivery Term at the applicable Market Price Referent specified below for the Facility's actual Commercial Operation Date. Payment shall be adjusted by the appropriate Time of Delivery ("TOD") factor listed in Appendix C.

Adopted 2008 Market Price Referents[1] (Nominal - dollars/kWh)			
Resource Type	10-Year	15-Year	20-Year
2009 Baseload MPR	0.10043	0.10537	0.11126
2010 Baseload MPR	0.10175	0.10748	0.11390
2011 Baseload MPR	0.10400	0.11046	0.11730
2012 Baseload MPR	0.10698	0.11405	0.12126
2013 Baseload MPR	0.10998	0.11776	0.12527
2014 Baseload MPR	0.11278	0.12122	0.12897
2015 Baseload MPR	0.11605	0.12503	0.13290
2016 Baseload MPR	0.11971	0.12915	0.13706
2017 Baseload MPR	0.12367	0.13352	0.14144
2018 Baseload MPR	0.12802	0.13814	0.14603
2019 Baseload MPR	0.13271	0.14298	0.15080
2020 Baseload MPR	0.13776	0.14797	0.15578

[1] Note: Using 2009 as the base year, Staff calculates MPRs for 2009-2020 that reflect different project online dates. Link to 2008 MPR Model: http://www.ethree.com/MPR.html

2.5 Billing. PG&E shall pay Seller by check or Automated Clearing House transfer within approximately 30 days of the meter reading date if the value of the purchased energy in a month is at least fifty dollars ($50); if less, PG&E may pay Seller quarterly. PG&E shall have the right, but not the obligation, to read the Facility's meter on a daily basis.

2.6 Title and Risk of Loss. Title to and risk of loss related to the energy produced from and capacity provided by the Facility shall transfer from Seller to PG&E at the Delivery Point. Seller warrants that it will deliver to PG&E all energy and capacity from the Facility free and clear of all liens, security interests, claims and encumbrances or any interest therein or thereto by any person arising prior to the Delivery Point.

2.7 No Additional Incentives. Seller agrees that during the Term of this Agreement, Seller shall not seek additional compensation or other benefits pursuant to the Self-Generation Incentive Program, as defined in CPUC Decision ("D.") 01-03-073, the California Solar Initiative, as defined in CPUC D.06-01-024, PG&E's net energy metering tariff, or other similar California ratepayer subsidized program relating to energy production with respect to the Facility.

2.8 Private Energy Producer. Seller agrees to provide to Buyer copies of each of the documents identified in PUC Section 2821(d)(1), if applicable, as may be amended from time to time, as evidence of Seller's compliance with such PUC section. Such documentation shall be provided to Buyer within thirty (30) days of Seller's receipt of written request therefor.

3. GREEN ATTRIBUTES; RESOURCE ADEQUACY BENEFITS

3.1 Conveyance of Green Attributes. Seller provides and conveys all Green Attributes from the Facility to Buyer as part of the Product (energy and capacity) delivered to Buyer for the duration of the Delivery Term. Seller represents and warrants that Seller holds the rights to all Green Attributes from the Facility, and Seller agrees to convey and hereby conveys all such Green Attributes to Buyer as included in the delivery of the Product from the Facility. Further, "Green Attributes" also means any and all credits that satisfy the requirement to procure electricity from ERRs, pursuant to the California Renewables Portfolio Standard, that are directly attributable to electric production from the Facility. Seller represents that the energy, capacity, ancillary services and Green Attributes from the Facility have not been, nor will be, sold or used to satisfy any obligation other than PG&E's California Renewables Portfolio Standard obligation.

3.2 WREGIS. Prior to the Initial Energy Delivery Date, Seller shall register the Facility in WREGIS and take all other actions necessary to ensure that the energy produced from the Facility is tracked for purposes of satisfying the California Renewables Portfolio Standard requirements, as may be amended or supplemented by the CPUC or CEC from time to time. Seller warrants that it shall take all necessary steps to ensure the Renewable Energy Credits transferred to Buyer under this Agreement are tracked in WREGIS and transferred in a timely manner to Buyer through WREGIS for purposes of satisfying Buyer's California Renewables Portfolio Standard Requirements, as may be amended or supplemented by the CPUC or CEC from time to time.

3.3 Resource Adequacy Benefits. In accordance with PUC Section 399.20(g), Seller conveys to PG&E all Resource Adequacy Benefits attributable to the physical generating capacity of Seller's Facility to enable PG&E to count such capacity towards PG&E's resource adequacy requirement for purposes of PUC Section 380. Seller shall take all reasonable actions and execute documents and instructions necessary to enable Buyer to secure Resource Adequacy Benefits; Seller shall comply with all applicable reporting requirements.

4. REPRESENTATION AND WARRANTIES; COVENANTS

4.1 Representations and Warranties. On the Execution Date, each Party represents and warrants to the other Party that:

4.1.1 it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

4.1.2 the execution, delivery and performance of this Agreement is within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

4.1.3 this Agreement and each other document executed and delivered in accordance with this Agreement constitutes its legally valid and binding obligation enforceable against it in accordance with its terms;

4.1.4 it is not bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming bankrupt;

4.1.5 there is not pending or, to its knowledge, threatened against it or any of its affiliates any legal proceedings that could materially adversely affect its ability to perform its obligations under this Agreement; and

4.1.6 it is acting for its own account, has made its own independent decision to enter into this Agreement and as to whether this Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing the merits of, and understands and accepts, the terms, conditions and risks of this Agreement.

4.2 General Covenants. Each Party covenants that throughout the Term of this Agreement:

4.2.1 it shall continue to be duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

4.2.2 it shall maintain (or obtain from time to time as required, including through renewal, as applicable) all regulatory authorizations necessary for it to legally perform its obligations under this Agreement; and

4.2.3 it shall perform its obligations under this Agreement in a manner that does not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it.

4.3 Seller Representation and Warranty and Covenant.

4.3.1 Representation and Warranty. In addition to the representations and warranties specified in Section 4.1, Seller makes the following additional representations and warranties as of the Execution Date:

(a) Seller's Facility is (check one) ☐ a facility owned by a state, local, or federal agency and used in the treatment or reclamation of sewage and industrial wastes; or ☐ a facility owned by a state, local, or federal agency that develops, stores, distributes or supplies water.

(b) Seller has not received an incentive under the Self-Generation Incentive Program, as defined in CPUC D.01-03-073, or the California Solar Initiative, as defined in CPUC D.06-01-024.

(c) Seller's execution of this Agreement will not violate PUC Section 2821(d)(1) if applicable.

4.3.2 Covenant. Seller hereby covenants that throughout the Term of the Agreement, the Facility is, or will qualify prior to the Initial Energy Delivery Date, as an ERR, specifically, Seller and, if applicable, its successors, represents and warrants throughout the term of the Delivery Term of each Transaction entered into under this Agreement that: (a) the Unit(s) qualifies and is certified by the CEC as an Eligible Renewable Energy Resource; and (b) the Unit(s) output delivered to Buyer qualifies under the requirements of the California Renewables Portfolio Standard. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

GENERAL CONDITIONS

4.4 Facility Care, Interconnection and Transmission Service. If PG&E does not deem Seller's existing interconnection service, equipment and agreement satisfactory for the delivery of energy under this Agreement, Seller shall execute a Small Generator Interconnection Agreement with PG&E's Generation Interconnection Services Department and pay and be responsible for designing, installing, operating, and maintaining the Facility in accordance with all applicable laws and regulations and shall comply with all applicable PG&E, CAISO, CPUC and FERC tariff provisions, including applicable interconnection and metering requirements. Seller shall also comply with any modifications, amendments or additions to the applicable tariff and protocols. During the Delivery Term, Seller shall arrange and pay independently for any and all necessary costs under any interconnection agreement with PG&E. To make deliveries to PG&E, Seller must maintain an interconnection agreement with PG&E in full force and effect.

4.5 Metering Requirements. Seller shall comply with all applicable rules in installing a meter appropriate for deliveries pursuant to the Full Buy/Sell or Excess Sale arrangement selected in paragraph 2.2, above, which can be electronically read daily by: (a) a telephone and modem; (b) an analog or digital phone connection; or (c) an internet portal address for PG&E's Energy Data Services ("EDS"). Seller shall be responsible for procuring and maintaining the communication link to electronically retrieve this metering data.

4.6 Standard of Care. Seller shall: (a) maintain and operate the Facility and Interconnection Facilities, except facilities installed by PG&E, in conformance with all applicable laws and regulations and in accordance with Good Utility Practices, as defined by PG&E's Wholesale Distribution Tariff and the CAISO Tariff, as they may be amended, supplemented or replaced (in whole or in part) from time to time; (b) obtain any governmental authorizations and permits required for the construction and operation thereof; and (c) generate, schedule and perform transmission services in compliance with all applicable operating policies, criteria, rules, guidelines and tariffs and Good Utility Practices, as provided in clause (a) above. Seller shall reimburse PG&E for any and all losses, damages, claims, penalties, or liability PG&E incurs as a result of Seller's failure to obtain or maintain any governmental authorizations and permits required for construction and operation of the Facility throughout the Term of this Agreement.

4.7 Access Rights. PG&E, its authorized agents, employees and inspectors shall have the right to inspect the Facility on reasonable advance notice during normal business hours and for any purposes reasonably connected with this Agreement or the exercise of any and all rights secured to PG&E by law, or its tariff schedules, PG&E Interconnection Handbook and rules on file with the CPUC. PG&E shall make reasonable efforts to coordinate its emergency activities with the Safety and Security Departments, if any, of the Facility operator. Seller shall keep PG&E advised of current procedures for communicating with the Facility operator's Safety and Security Departments.

4.8 Protection of Property. Each Party shall be responsible for protecting its own facilities from possible damage resulting from electrical disturbances or faults caused by the operation, faulty operation, or non-operation of the other Party's facilities and such other Party shall not be liable for any such damages so caused.

4.9 PG&E Performance Excuse; Seller Curtailment.

4.9.1 PG&E Performance Excuse. PG&E shall not be obligated to accept or pay for energy produced by or capacity provided from the Facility during a Dispatch Down Period, or Force Majeure, as defined in Appendix A.

4.9.2 Seller Curtailment. PG&E may require Seller to interrupt or reduce deliveries of energy: (a) when necessary to construct, install, maintain, repair, replace, remove, or investigate any of its equipment or part of PG&E's transmission system or distribution system or facilities; or (b) if PG&E or the CAISO determines that curtailment, interruption, or reduction is necessary because of a System Emergency, as defined in the CAISO Tariff, Forced Outage, Force Majeure as defined in Appendix A, or compliance with Good Utility Practice, as such term is defined in the CAISO Tariff.

4.10 Notices of Outages. Whenever possible, PG&E shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries may be required.

4.11 Greenhouse Gas Emissions: During the Term, Seller acknowledges that a Governmental Authority may require Buyer to take certain actions with respect to greenhouse gas emissions *attributable to the generation of Energy*, including, but not limited to, reporting, registering, tracking, allocating for or accounting for such emissions. Promptly following Buyer's written request, Seller agrees to take all commercially reasonable actions and execute or provide any and all documents, information or instruments *with respect to generation by the Project* reasonably necessary to permit Buyer to comply with such requirements, if any.

5. INDEMNITY

Each Party as indemnitor shall save harmless and indemnify the other Party and the directors, officers, and employees of such other Party against and from any and all loss and liability for injuries to persons including employees of either Party, and damages, including property of either Party, resulting from or arising out of: (a) the engineering, design, construction, maintenance, or operation of; or (b) the installation of replacements, additions, or betterments to the indemnitor's facilities. This indemnity and save harmless provision shall apply notwithstanding the active or passive negligence of the indemnitee. Neither Party shall be indemnified for liability or loss, resulting from its sole negligence or willful misconduct. The indemnitor shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity and shall pay all costs, including reasonable attorney fees that may be incurred by the other Party in enforcing this indemnity.

6. LIMITATION OF DAMAGES

EXCEPT AS OTHERWISE PROVIDED IN THIS AGREEMENT THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY

AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED UNLESS EXPRESSLY HEREIN PROVIDED. NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. UNLESS EXPRESSLY HEREIN PROVIDED, AND SUBJECT TO THE PROVISIONS OF SECTION 6 (INDEMNITY), IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE.

7. NOTICES

Notices shall, unless otherwise specified herein, be in writing and may be delivered by hand delivery, United States mail, overnight courier service, facsimile or electronic messaging (e-mail). Whenever this Agreement requires or permits delivery of a "notice" (or requires a Party to "notify"), the Party with such right or obligation shall provide a written communication in the manner specified below. A notice sent by facsimile transmission or e-mail will be recognized and shall be deemed received on the Business Day on which such notice was transmitted if received before 5 p.m. Pacific prevailing time (and if received after 5 p.m., on the next Business Day) and a notice by overnight mail or courier shall be deemed to have been received two (2) Business Days after it was sent or such earlier time as is confirmed by the receiving Party unless it confirms a prior oral communication, in which case any such notice shall be deemed received on the day sent. A Party may change its addresses by providing notice of same in accordance with this provision. All written notices shall be directed as follows:

TO PG&E: Pacific Gas and Electric Company
Attention: Manager, Contract Management
245 Market Street, Mail Code N12E
San Francisco, CA 94177-0001

TO SELLER: ______________
____
____
____

8. INSURANCE

8.1 General Liability Coverage.

8.1.1 Seller shall maintain during the performance hereof, General Liability Insurance[2] of not less than $1,000,000 if the Facility's nameplate is over 100 kW, $500,000 if the nameplate rating of the Facility is over 20 kW to 100kW or $100,000 if the nameplate rate of the Facility is 20 kW or below of combined single limit or equivalent for bodily injury, personal injury, and property damage as the result of any one occurrence.

8.1.2 General Liability Insurance shall include coverage for Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations.

8.1.3 Such insurance shall provide for thirty (30) days written notice to PG&E prior to cancellation, termination, alteration, or material change of such insurance.

8.2 Additional Insurance Provisions.

8.2.1 Evidence of coverage described above in Paragraph 9.1 shall state that coverage provided in primary and is not excess to or contributing with any insurance or self-insurance maintained by PG&E.

8.2.2 PG&E shall have the right to inspect or obtain a copy of the original policy(ies) of insurance.

8.2.3 Seller shall furnish the required certificates and endorsements to PG&E prior to commencing operation.

8.2.4 All insurance certificates, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

Pacific Gas and Electric Company

Attention: Manager, Insurance Department

77 Beale Street, Room E280

San Francisco, CA 94105

9. TERM, DEFAULT, TERMINATON EVENT AND TERMINATION

9.1 Term. The term of this Agreement shall commence upon the later of: (i) execution by the duly authorized representatives of each of PG&E and Seller; or (ii) when PG&E notifies Seller that PG&E can accommodate Seller's Facility in PG&E's

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2 Governmental agencies which have an established record of self-insurance may provide the required coverage through self-insurance.

proportionate share of the statewide cumulative total of 250 MW as specified in PUC Section 399.20(e), and shall remain in effect until the conclusion of the Delivery Term or unless terminated sooner pursuant to Section 10.3 of this Agreement (the "Term"). All indemnity rights shall survive the termination of this Agreement for twelve (12) months.

9.2 Termination Event. Buyer shall be entitled to terminate the Agreement upon the occurrence of any of the following, each of which is a "Termination Event":

(a) The Facility has not achieved Commercial Operation within eighteen (18) months of the Execution Date of this Agreement;

(b) Seller has not sold or delivered energy from the Facility to PG&E for a period of twelve (12) consecutive months;

(c) Seller breaches its covenant to maintain its status as an ERR as set forth in Section 4.3.2. of the Agreement.

9.3 Termination.

9.3.1 Declaration of a Termination Event. If a Termination Event has occurred and is continuing, Buyer shall have the right to: (a) send notice, designating a day, no earlier than five days after such notice is deemed to be received (as provided in Section 8) and no later than 20 days after such notice is deemed to be received (as provided in Section 8), as an early termination date of this Agreement ("Early Termination Date") unless Seller has timely communicated with Buyer and the Parties have agreed to resolve the circumstances giving rise to the termination Event; (b) accelerate all amounts owing between the Parties; and (c) terminate this Agreement and end the Delivery Term effective as of the Early Termination Date.

9.3.2 Release of Liability for Termination Event. Upon termination of this Agreement pursuant to Section 10.3.1, neither Party shall be under any further obligation or subject to liability hereunder, except with respect to the indemnity provision in Section 6 hereof, which shall remain in effect for a period of 12 months following the Early Termination Date.

10. SCHEDULING

11.1 Scheduling Obligations. PG&E shall be Seller's designated Scheduling Coordinator (as defined by CAISO tariff). PG&E will schedule Seller' project using Prudent Utility Practices and Seller shall employ Prudent Utility Practices and exercise reasonable efforts to operate and maintain its project. All generation interconnection and scheduling services shall be performed in accordance with all applicable operating policies, criteria, guidelines and tariffs of the CAISO or its successor, and any other generally accepted operational requirements. Seller, at its own expense, shall be responsible for complying with all applicable contractual, metering and interconnection requirements. Seller shall promptly notify PG&E of significant (i.e., greater than 100 kW) changes to its energy schedules using PG&E's web site (see Appendix D). Seller will exercise reasonable efforts to comply with conditions that might arise if the CAISO modifies or amends its tariffs, standards, requirements, and/or protocols in the future.

11.2 CAISO Charges.

11.2.1 CAISO Charge Obligations. PG&E and Seller shall cooperate to minimize CAISO delivery imbalances and any resulting fees, liabilities, assessments or similar charges assessed by the CAISO ("CAISO Charges") to the extent possible, and shall each promptly notify the other as soon as possible of any material loss of system capability, deviation or imbalance that is occurring or has occurred. Seller shall reimburse PG&E for any CAISO Charges PG&E incurs as a result of Seller's loss of system capability, deviation or imbalance. Any such CAISO Charges reimbursable to PG&E shall be limited to the period until the commencement of the next settlement period following Seller's notification for which the delivery schedule can be adjusted. Notwithstanding anything to the contrary herein, in the event Seller makes a change to its schedule on the actual date and time of delivery for any reason (other than an adjustment imposed by CAISO) which results in differences between the project's actual generation and the scheduled generation (whether in part or in whole), Seller shall use reasonable efforts to notify PG&E. PG&E will make commercially reasonable efforts to accommodate Seller's changes and mitigate any imbalance penalties or charges levied for such changes.

11.2.2 CAISO Penalties. Seller shall be responsible for any "non-Performance Penalties" assessed to PG&E by the CAISO ("CAISO Penalties"), under the CAISO Tariff Enforcement Protocol, and not due to any fault of PG&E, which shall include, without limitation, any deviation, imbalance or uninstructed energy charges or penalties payable to the CAISO that are due to the fault of Seller. To the extent that Seller materially deviates from its energy schedules (other than an adjustment imposed by the CAISO, a deviation due to any fault of PG&E, or an excused Seller failure to deliver, whether for reasons of Force Majeure or otherwise), and such departure results in CAISO Penalties being assessed to PG&E, such CAISO Penalties shall be passed on to Seller. Any such CAISO Penalties passed on to Seller shall be limited to the period until the commencement of the next settlement period following Seller's notification (as described above) for which the delivery schedule can be adjusted.

11. CONFIDENTIALITY

Seller authorizes PG&E to release to the California Energy Commission ("CEC") and/or the CPUC information regarding the Facility, including the Seller's name and location, and the size, location and operational characteristics of the Facility, the Term, the ERR type, the Initial Energy Delivery Date and the net power rating of the Facility, as requested from time to time pursuant to the CEC's or CPUC's rules and regulations.

12. ASSIGNMENT

Neither Party shall assign this Agreement or its rights hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder), transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof to its financing providers and the financing provider(s) shall assume the payment and performance obligations provided under this Agreement with respect to the transferring Party provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request.

13. APPLICABLE LAW

THIS AGREEMENT AND THE RIGHTS AND DUTIES OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF CALIFORNIA, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW. TO THE EXTENT ENFORCEABLE AT SUCH TIME, EACH PARTY WAIVES ITS RESPECTIVE RIGHT TO ANY JURY TRIAL WITH RESPECT TO ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS AGREEMENT.

14. SEVERABILITY

If any provision in this Agreement is determined to be invalid, void or unenforceable by the CPUC or any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Agreement and the Parties shall use their best efforts to modify this Agreement to give effect to the original intention of the Parties.

15. COUNTERPARTS

This Agreement may be executed in one or more counterparts each of which shall be deemed an original and all of which shall be deemed one and the same Agreement. Delivery of an executed counterpart of this Agreement by facsimile or PDF transmission will be deemed as effective as delivery of an originally executed counterpart. Each Party delivering an executed counterpart of this Agreement by facsimile or PDF transmission will also deliver an originally executed counterpart, but the failure of any Party to deliver an originally executed counterpart of this Agreement will not affect the validity or effectiveness of this Agreement.

16. GENERAL

The CPUC has reviewed and approved this Agreement. No amendment to or modification of this Agreement shall be enforceable unless reduced to writing and executed by both parties. This Agreement shall not impart any rights enforceable by any third party other than a permitted successor or assignee bound to this Agreement. Waiver by a Party of any default by the other Party shall not be construed as a waiver of any other default. The term "including" when used in this Agreement shall be by way of example only and shall not be considered in any way to be in limitation. The headings used herein are for convenience and reference purposes only.

IN WITNESS WHEREOF, each Party has caused this Agreement to be duly executed by its authorized representative as of the date of last signature provided below.

PACIFIC GAS AND ELECTRIC COMPANY

By: ______________________________ Date: ______________________________

Name: ______________________________

Title: ______________________________

SELLER

By: ______________________________ Date: ______________________________

Name: ______________________________

Title: ______________________________

Appendix A

DEFINITIONS

"Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday during the hours of 8:00 a.m. and 5:00 p.m. local time for the relevant Party's principal place of business where the relevant Party in each instance shall be the Party from whom the notice, payment or delivery is being sent.

"CAISO" means the California Independent System Operator Corporation or any successor entity performing similar functions.

"CAISO Tariff" means the CAISO FERC Electric Tariff, Third Replacement Volume No. 1, as amended from time to time.

"California Renewables Portfolio Standard" means the renewable energy program and policies established by Senate Bill 1038 and 1078, codified in California Public Utilities Code Sections 399.11 through 399.20 and California Public Resources Code Sections 25740 through 25751, as such provisions may be amended or supplemented from time to time.

"CEC" means the California Energy Commission or its successor agency.

"Commercial Operation Date" means the date on which the Facility is operating and is in compliance with applicable interconnection and system protection requirements, and able to produce and deliver energy to PG&E pursuant to the terms of this Agreement.

"Contract Year" means a period of twelve (12) consecutive months with the first Contract Year commencing on the first day of the month immediately following the Initial Energy Delivery Date and each subsequent Contract Year commencing on the anniversary of the Initial Energy Delivery Date.

"CPUC" means the California Public Utilities Commission, or successor entity.

"Delivery Point" means the point of interconnection to the PG&E distribution system.

"Dispatch Down Period" means: (a) curtailments ordered by the CAISO or PG&E as a result of a System Emergency, as defined in the CAISO Tariff; or (b) scheduled or unscheduled maintenance on PG&E's transmission, distribution or interconnection facilities that prevents Buyer from receiving Delivered Energy at the Delivery Point. Notwithstanding the foregoing sentence, Buyer shall have the option in its sole discretion to curtail Seller's energy deliveries up to 50 (fifty) hours each calendar year.

"Eligible Renewable Energy Resource" or "ERR" has the meaning set forth in Public Utilities Code Sections 399.12 and California Public Resources Code Section 25741, as either code provision may be amended or supplemented from time to time.

"Execution Date" means the latest signature date found at the end of the Agreement.

"FERC" means the Federal Energy Regulatory Commission or any successor

government agency.

"Forced Outage" means any unplanned reduction or suspension of the electrical output from the Facility resulting in the unavailability of the Facility, in whole or in part, in response to a mechanical, electrical, or hydraulic control system trip or operator-initiated trip in response to an alarm or equipment malfunction and any other unavailability of the Facility for operation, in whole or in part, for maintenance or repair that is not a scheduled maintenance outage and not the result of Force Majeure.

"Force Majeure" means any event or circumstance which wholly or partly prevents or delays the performance of any material obligation arising under this Agreement, but only if and to the extent (i) such event is not within the reasonable control, directly or indirectly, of the Party seeking to have its performance obligation(s) excused thereby, (ii) the Party seeking to have its performance obligation(s) excused thereby has taken all reasonable precautions and measures to prevent or avoid such event or mitigate the effect of such event on such Party's ability to perform its obligations under this Agreement and which by the exercise of due diligence such Party could not reasonably have been expected to avoid and which by the exercise of due diligence it has been unable to overcome, and (iii) such event is not the direct or indirect result of the negligence or the failure of, or caused by, the Party seeking to have its performance obligations excused thereby. Force Majeure shall not be based on: (i) PG&E's inability economically to use or resell the energy or capacity purchased hereunder; (ii) Seller's ability to sell the energy, capacity or other benefits produced by or associated with the Facility at a price greater than the price set forth in this Agreement, (iii) Seller's inability to obtain approvals of any type for the construction, operation, or maintenance of the Facility; (iv) Seller's inability to obtain sufficient fuel to operate the Facility, except if Seller's inability to obtain sufficient fuel is caused by an event of Force Majeure of the specific type described in any of subsections (i) through (iv) of this definition of Force Majeure; (v) a Forced Outage except where such Forced Outage is caused by an event of Force Majeure of the specific type described in any of subsections (i) through (iv) of this definition of Force Majeure; (vi) a strike or labor dispute limited only to Seller, Seller's affiliates, the Engineering, Procurement, and Construction Contractor or subcontractors thereof; or (vii) any equipment failure not caused by an event of Force Majeure of the specific type described in any of subsections (i) through (iv) of this definition of Force Majeure.

"Green Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Facility, and its displacement of conventional energy generation. Green Attributes include but are not limited to Renewable Energy Credits, as well as: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4) nitrous oxide, hydrofluoro carbons, perfluoro carbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere; (3) the reporting rights to these avoided emissions such as Green Tag Reporting Rights. Green Tag Reporting Rights are the right of a Green Tag Purchaser to report the ownership of accumulated Green Tags in

compliance with federal or state law, if applicable, and to a federal or state agency or any other party at the Green Tag Purchaser's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on MWh basis and one Green Tag represents the Green Attributes associated with one (1) MWh of energy. Green Attributes do not include: (i) any energy, capacity, reliability or other power attributes from the Facility; (ii) production tax credits associated with the construction or operation of the energy projects and other financial incentives in the form of credits, reductions, or allowances associated with the project that are applicable to a state or federal income taxation obligation; (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular pre-existing pollutants or the promotion of local environmental benefits; or (iv) emission reduction credits encumbered or used by the Facility for compliance with local, state, or federal operating and/or air quality permits. If Seller's Facility is a biomass or landfill gas facility and Seller receives any tradable Green Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide Buyer with sufficient Green Attributes to ensure that there are zero net emissions associated with the production of electricity from such facility.

"Law" means any statute, law, treaty, rule, regulation, ordinance, code, permit, enactment, injunction, order, writ, decision, authorization, judgment, decree or other legal or regulatory determination or restriction by a court or Governmental Authority of competent jurisdiction, including any of the foregoing that are enacted, amended, or issued after the Execution Date, and which becomes effective during the Delivery Term; or any binding interpretation of the foregoing.

"Market Price Referent" means the market price referent applicable to this Agreement, as determined by the CPUC in accordance with Public Utilities Code Section 399.15(c), as may be amended or modified from time to time.

"Renewable Energy Credit" has the meaning set forth in Public Utilities Code Section 399.12(g), as may be amended from time to time or as further defined or supplemented by Law.

"Resource Adequacy Benefits" means the rights and privileges attached to the Facility that satisfy any entity's resource adequacy obligations, as those obligations are set forth in any Resource Adequacy Rulings and shall include any local, zonal or otherwise locational attributes associated with the Facility.

"Resource Adequacy Rulings" means CPUC Decisions 04-01-050, 04-10-035, 05-10-042, 06-06-064, 06-07-031 and any subsequent CPUC ruling or decision, or any other resource adequacy laws, rules or regulations enacted, adopted or promulgated by any applicable governmental authority, as such decisions, rulings, laws, rules or regulations may be amended or modified from time-to-time during the Delivery Term.

"Station use" means energy consumed within the Facility's electric energy

distribution system as losses, as well as energy used to operate the Facility's auxiliary equipment. The auxiliary equipment may include, but is not limited to, forced and induced draft fans, cooling towers, boiler feeds pumps, lubricating oil systems, plant lighting, fuel handling systems, control systems, and sump pumps.

"WREGIS" means the Western Renewable Energy Generating Information System or any successor renewable energy tracking program.

Appendix B

INITIAL ENERGY DELIVERY DATE CONFIRMATION LETTER

In accordance with the terms of that certain Section 399.20 Power Purchase Agreement dated _______ ("Agreement") by and between Pacific Gas and Electric Company ("PG&E") and _______________ ("Seller"), this letter serves to document the parties further agreement that (i) the conditions precedent to the occurrence of the Initial Energy Delivery Date have been satisfied, and (ii) Seller has scheduled and PG&E has received the energy, as specified in the Agreement, as of this _____ day of ______, ______. This letter shall confirm the Initial Energy Delivery Date, as defined in the Agreement, as the date referenced in the preceding sentence. .

IN WITNESS WHEREOF, each Party has caused this Agreement to be duly executed by its authorized representative as of the date of last signature provided below:

By:	By: Pacific Gas and Electric Company
Name: ________________________	Name: __________________________
Title: ________________________	Title: __________________________
Date: ________________________	Date: __________________________

Appendix C

Time of Delivery (TOD) Periods & Factors

Monthly Period	Super-Peak[1]	Shoulder[2]	Night[3]
Jun – Sep	2.01	1.14	0.72
Oct.- Dec., Jan. & Feb.	1.09	.96	0.78
Mar. – May	1.13	0.86	0.63

Definitions:

1. Super-Peak (5x8) = HE (Hours Ending) 13 – 20 (Pacific Prevailing Time (PPT)), Monday - Friday (*except* NERC holidays) in the applicable Monthly Period.
2. Shoulder = HE 7 - 12, 21 and 22 PPT, Monday - Friday (*except* NERC holidays); and HE 7 - 22 PPT Saturday, Sunday and *all* NERC holidays in the applicable Monthly Period.
3. Night (7x8) = HE 1 - 6, 23 and 24 PPT all days *(including* NERC holidays) in the applicable Monthly Period.

"NERC Holidays" mean the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Three of these days, Memorial Day, Labor Day, and Thanksgiving Day occur on the same day each year. Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the 4th Thursday in November. New Year's Day, Independence Day, and Christmas Day, by definition, are predetermined dates each year. However, in the event they occur on a Sunday, the "NERC Holiday" is celebrated on the Monday immediately following that Sunday. However, if any of these days occur on a Saturday, the "NERC Holiday" remains on that Saturday.

Appendix D

COUNTERPARTY NOTIFICATION AND FORECASTING REQUIREMENTS

A. NOTIFICATION REQUIREMENTS FOR START-UP AND SHUTDOWN

Prior to paralleling to or after disconnecting from the electric system, ALWAYS notify your designated Distribution Operator as follows:

1. Call your Distribution Operator for permission to parallel before any start-up.
2. Call your Distribution Operator again after start-up with parallel time.
3. Call your Distribution Operator after any separation and report separation time as well as date and time estimate for return to service.

B. FORECASTING REQUIREMENTS

1. Seller shall abide with all established requirements and procedures described below:

(a) Generating Facilities 1000 kW and greater must comply with the CAISO Tariff and Protocols while generating facilities under 1000 kW must comply with all applicable interconnection, communication and metering rules; and

(b) Generating Facilities 100 kW and greater must provide a weekly forecast of their expected generation output.

2. Weekly Energy Forecasting Procedures.

Seller must meet all of the following requirements specified below:

Beginning the Wednesday prior to the planned Initial Operation of the Generating Facility, Seller will electronically provide PG&E with an Energy Forecast for the next calendar week, by no later than 5 PM Wednesday of the week preceding the week covered by the Energy Forecast.

The Weekly Energy Forecast submitted to PG&E shall:
a) Not include any anticipated or expected electric energy losses;
b) Be submitted using PG&E's website at https://www.pge.com/qic with Login and password information to be provided, or as otherwise instructed by PG&E;
c) Include Seller's contact information;
d) Limit Day Ahead forecast changes to no less than 100 kW.

2. Outage and Scheduled Maintenance Reporting Procedures.

Send notices of extended outages and proposed scheduled maintenances to PG&E's Internet site (QFSchedules@pge.com). Access and your password to this web site will be provided upon execution of the power purchase agreement.

E-SRG Reference	E-PWF Reference	CURRENT LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARDCONTRACTS	PG&E's PROPOSED LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARD CONTRACTS
Proposed Modifications in Advice 3410-E-A			
PPA - Section 3.2 WREGIS	PPA - Section 3.2 WREGIS	3.2 WREGIS. Prior to the Initial Energy Delivery Date, Seller shall register the Facility in WREGIS and take all other actions necessary to ensure that the energy produced from the Facility is tracked for purposes of satisfying the California Renewables Portfolio Standard requirements, as may be amended or supplemented by the CPUC or CEC from time to time. In the event that WREGIs is not in operation as of the Initial Energy Delivery Date, Seller shall perform its obligations as required by this subsection as soon WREGIS is in operation.	3.2 WREGIS. Prior to the Initial Energy Delivery Date, Seller shall register the Facility in WREGIS and take all other actions necessary to ensure that the energy produced from the Facility is tracked for purposes of satisfying the California Renewables Portfolio Standard requirements, as may be amended or supplemented by the CPUC or CEC from time to time. Seller warrants that ~~all~~ it shall take all necessary steps ~~have been taken~~ to ~~allow~~ensure the ~~R~~renewable ~~E~~energy ~~C~~credits transferred to Buyer under this Agreement are tracked in WREGIS and transferred in a timely manner to Buyer through WREGIS for purposes of satisfying Buyer's California Renewables Portfolio Standard Requirements, as may be amended or supplemented by the CPUC or CEC from time to time.~~to be tracked in the Western Renewable Energy Generation Information System.~~
PPA – 10.2 Termination Event Section	PPA – 9.2 Termination Event Section	10.2 (E-SRG) and 9.2 (E-PWF) Termination Event. Buyer shall be entitled to terminate the Agreement upon the occurrence of any of the following, each of which is a "Termination Event": (a) The Facility has not achieved Commercial Operation within eighteen (18) months of the Execution Date of this Agreement; (b) Seller has not sold or delivered energy from the Facility to PG&E for a period of twelve (12) consecutive months; (c) All the Agreements whose combined capacity fill PG&E's proportionate share as determined by PUC Section 399.20 are operational; or (d) Seller breaches its covenant to maintain its status as an ERR as set forth in Section 4.3.2. of the Agreement.	10.2 Termination Event. Buyer shall be entitled to terminate the Agreement upon the occurrence of any of the following, each of which is a "Termination Event": (a) The Facility has not achieved Commercial Operation within eighteen (18) months of the Execution Date of this Agreement; (b) Seller has not sold or delivered energy from the Facility to PG&E for a period of twelve (12) consecutive months; ~~(c) All the Agreements whose combined capacity fill PG&E's proportionate share as determined by PUC Section 399.20 are operational; or~~ (c) Seller breaches its covenant to maintain its status as an ERR as set forth in Section 4.3.2. of the Agreement.
PPA - Climate Action	PPA - Climate Action	(iii) the Facility is registered with the California Climate Action Registry as provided in Section 5.8. As evidence of the Initial Energy Delivery Date, the Parties shall execute and	~~(iii) the Facility is registered with the California Climate Action Registry as provided in Section 5.8.~~ As evidence of the Initial Energy Delivery Date, the Parties shall execute and exchange

E-SRG Reference	E-PWF Reference	CURRENT LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARDCONTRACTS	PG&E's PROPOSED LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARD CONTRACTS
Registry Section	Registry Section	exchange the "Initial Energy Delivery Date Confirmation Letter" attached hereto as Appendix B on the Initial Energy Delivery Date. 5.8 (E-SRG) 4.11 (E-PWF)Climate Action Registry. Seller shall register the Facility with the California Climate Action Registry as may be required by the CPUC pursuant to CPUC D. 06-02-032 and any subsequent order, but in any event, no later than the Initial Energy Delivery Date. Seller shall report greenhouse gas emissions output from the Facility if PG&E so requests. Seller shall be liable for all reasonable expenses PG&E incurs resulting from Seller's failure to comply with this provision to the extent that PG&E must estimate greenhouse gas emissions and report these emissions in satisfaction of certain legal or regulatory requirements.	the "Initial Energy Delivery Date Confirmation Letter" attached hereto as Appendix B on the Initial Energy Delivery Date. [Replace Section 5.8 with:] 5.8/4.11 Greenhouse Gas Emissions: During the Term, Seller acknowledges that a Governmental Authority may require Buyer to take certain actions with respect to greenhouse gas emissions *attributable to the generation of Energy*, including, but not limited to, reporting, registering, tracking, allocating for or accounting for such emissions. Promptly following Buyer's written request, Seller agrees to take all commercially reasonable actions and execute or provide any and all documents, information or instruments *with respect to generation by the Project* reasonably necessary to permit Buyer to comply with such requirements, if any.
Proposed Modifications in Advice 3410-E			
Tariff and PPA – MPR and TOD Section	Tariff and PPA – MPR and TOD Section	Replace 2007 MPR and TOD factors with 2008 MPR and TOD factors	Replace 2007 MPR and TOD factors with 2008 MPR and TOD factors
Tariff – Applicability Section	Tariff – Applicability Section	APPLICABILITY: This Schedule is optional for customers who meet the definition of an Eligible Public Water Facility or Eligible Public Wastewater Facility and own an Eligible Renewable Energy Resource as defined in the Special Conditions section of this Schedule, with a total effective generation capacity of not more than 1.5 megawatts. Service under this Schedule is on a first-come-first-served basis and shall be closed to new customers once the combined rated generating capacity of Eligible Renewable Energy Resource within PG&E's service territory reaches 104.603 megawatts, as set forth in D. 07-07-027, effective July 26, 2007.	APPLICABILITY: This Schedule is optional for customers who meet the definition of an Eligible Public Water Facility or Eligible Public Wastewater Facility and own an Eligible Renewable Energy Resource as defined in the Special Conditions section of this Schedule, with a total effective generation capacity of not more than 1.5 megawatts. Service under this Schedule is on a first-come-first-served basis and shall be closed to new customers once the combined rated generating capacity of Eligible Renewable Energy Resource within PG&E's service territory reaches 104.603 megawatts, as set forth in D. 07-07-027, effective July 26, 2007. An electric generation facility must meet the criteria listed in Public Utilities Code section 399.20(b) as follows: (1) Has an effective capacity of not more than one and one-half megawatts and is located on property owned or under the control of the customer. (2) Is interconnected and operates in parallel with the electric

E-SRG Reference	E-PWF Reference	CURRENT LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARDCONTRACTS	PG&E's PROPOSED LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARD CONTRACTS
			transmission and distribution grid. (3) Is strategically located and interconnected to the electric transmission system in a manner that optimizes the deliverability of electricity generated at the facility to load centers.
Tariff – Special Conditions Section	Tariff – Special Conditions Section	2. Participation in other PG&E Programs: As set forth in Decision 07-07-027, customers taking service under this Schedule may not obtain benefits from both this Schedule and the Self-Generation Incentive Program, net metering programs, the California Solar Initiative, or other similar programs.	2. Participation in other PG&E Programs: As set forth in Decision 07-07-027, customers taking service under this Schedule may not obtain benefits from both this Schedule and the Self-Generation Incentive Program, net energy metering programs, the California Solar Initiative, or other similar programs.
Not Applicable	Tariff – Special Conditions Section	3. Definitions: The following definitions are applicable to service provided under this Schedule. a. Eligible Wastewater Facility - Any facility owned by a state, local, or federal agency and used in the treatment or reclamation of sewage and industrial wastes, and located on property owned or under the control of the public water or wastewater agency.	3. Definitions: The following definitions are applicable to service provided under this Schedule. a. Eligible Public Wastewater Facility - Any facility owned by a state, local, or federal agency and used in the treatment or reclamation of sewage and industrial wastes, and located on property owned or under the control of the public water or wastewater agency.
Tariff – Special Conditions Section	Tariff – Special Conditions Section	A definition for effective capacity was not previously included in the tariff.	d. Effective Capacity – The capacity of the eligible renewable generator as established by the manufacturer that is available for use either at-site to meet customer load or exported to the grid for sale to PG&E under the Section 399.20 PPA. PG&E will use either the nameplate rating of the eligible renewable generator if no inverter is used, or the inverter rating if the generator is inverter based.
PPA – Sections 2.1.7 and 2.1.8 under Seller's Generating Facility, Purchase Prices and Payment Section	PPA – Sections 2.1.7 and 2.1.8 under Seller's Generating Facility, Purchase Prices and Payment Section	This information was not previously included in the PPA.	2.1.7 A description of the Facility, including a summary of its significant components, a drawing showing the general arrangements of the Facility, and a single line diagram illustrating the interconnection of the Facility and loads with PG&E's electric distribution system, is attached and incorporated herein as Appendix E. 2.1.8 The name and address PG&E uses to locate the electric service account(s) and premises used to interconnect the Facility with PG&E's distribution systems is: ____________________

E-SRG Reference	E-PWF Reference	CURRENT LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARDCONTRACTS	PG&E's PROPOSED LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARD CONTRACTS
PPA – Section 2.7 No Additional Incentives	PPA – Section 2.7 No Additional Incentives	2.7 No Additional Incentives. Seller agrees that during the Term of this Agreement, Seller shall not seek additional compensation or other benefits pursuant to the Self-Generation Incentive Program, as defined in CPUC Decision ("D.") 01-03-073, the California Solar Initiative, as defined in CPUC D.06-01-024, PG&E's net metering tariff, or other similar California ratepayer subsidized program relating to energy production with respect to the Facility.	2.7 No Additional Incentives. Seller agrees that during the Term of this Agreement, Seller shall not seek additional compensation or other benefits pursuant to the Self-Generation Incentive Program, as defined in CPUC Decision ("D.") 01-03-073, the California Solar Initiative, as defined in CPUC D.06-01-024, PG&E's net energy metering tariff, or other similar California ratepayer subsidized program relating to energy production with respect to the Facility.
PPA – Appendix C TOD Factors Section	PPA – Appendix C TOD Factors Section	**Appendix C** **Time of Delivery (TOD) Periods & Factors** Definitions: 1. Super-Peak (5x8) = HE (Hours Ending) 13 - 20, Monday - Friday (*except* NERC holidays). 2. Shoulder = HE 7 - 12, 21 and 22, Monday - Friday (*except* NERC holidays); and HE 7 - 22 Saturday, Sunday and *all* NERC holidays. 3. Night (7x8) = HE 1 - 6, 23 and 24 all days (*including* NERC holidays). 4. NERC (Additional Off-Peak) Holiday include: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Three of these days, Memorial Day, Labor Day, and Thanksgiving Day occur on the same day each year. Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the 4th Thursday in November. New Year's Day, Independence Day, and Christmas Day, by definition, are predetermined dates each year. However, in the event they occur on a Sunday, the "NERC Additional Off-Peak Holiday" is celebrated on the Monday immediately following that Sunday. However, if any of these days occur on a Saturday, the "NERC Additional Off-Peak Holiday" remains on that Saturday.	**Appendix C** **Time of Delivery (TOD) Periods & Factors** Definitions: 2. Super-Peak (5x8) = HE (Hours Ending) 13 – 20 (Pacific Prevailing Time (PPT)), Monday - Friday (*except* NERC holidays) in the applicable Monthly Period. 2. Shoulder = HE 7 - 12, 21 and 22 PPT Monday - Friday (*except* NERC holidays); and HE 7 - 22 PPT Saturday, Sunday and *all* NERC holidays in the applicable Monthly Period. 3. Night (7x8) = HE 1 - 6, 23 and 24 PPT all days (*including* NERC holidays) in the applicable Monthly Period. ~~4.~~ "NERC ~~(Additional Off Peak)~~Holidays" mean the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Three of these days, Memorial Day, Labor Day, and Thanksgiving Day occur on the same day each year. Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the 4th Thursday in November. New Year's Day, Independence Day, and Christmas Day, by definition, are predetermined dates each year. However, in the event they occur on a Sunday, the "NERC ~~Additional Off-Peak~~ Holiday" is celebrated on the Monday immediately following that Sunday. However, if any of these days occur on a Saturday, the "NERC ~~Additional Off-Peak~~ Holiday" remains on that Saturday.

E-SRG Reference	E-PWF Reference	CURRENT LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARDCONTRACTS	PG&E's PROPOSED LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARD CONTRACTS
PPA Appendix D Section B Forecasting Requirements	PPA Appendix D Section B Forecasting Requirements	(b) Generating Facilities 100 kW and greater must provide a weekly forecast of their expected generation output or commit to a default schedule. 2. Weekly Energy Forecasting Procedures. Seller must meet all of the following requirements specified below: Beginning the Wednesday prior to the planned Initial Operation of the Generating Facility, Seller will electronically provide PG&E with an Energy Forecast for the next calendar week, by no later than 5 PM Wednesday of the week preceding the week covered by the Energy Forecast. The Weekly Energy Forecast submitted to PG&E shall: a) Not include any anticipated or expected electric energy losses; b) Be constructed using an excel file format and naming convention provided by PG&E; c) Include Seller's contact information; d) Be sent to QFSchedules@PG&E.com or as otherwise instructed by PG&E; e) Limit Day Ahead forecast changes to no less than 500 kW.	(b) Generating Facilities 100 kW and greater must provide a weekly forecast of their expected generation output ~~or commit to a default schedule~~. 2. Weekly Energy Forecasting Procedures. Seller must meet all of the following requirements specified below: Beginning the Wednesday prior to the planned Initial Operation of the Generating Facility, Seller will electronically provide PG&E with an Energy Forecast for the next calendar week, by no later than 5 PM Wednesday of the week preceding the week covered by the Energy Forecast. The Weekly Energy Forecast submitted to PG&E shall: a) Not include any anticipated or expected electric energy losses; b) Be ~~constructed using an excel file format and naming convention provided by PG&E~~ using PG&E's website at https://www.pge.com/qic with Login and password information to be provided, or as otherwise instructed by PG&E; c) Include Seller's contact information; ~~d) Be sent to QFSchedules@PG&E.com or as otherwise instructed by PG&E;~~ ~~e~~d) Limit Day Ahead forecast changes to no less than 1~~5~~00 kW.

APPENDIX B

Utility's 2008 Time-of-Delivery (TOD) periods and factors

PG&E[55]

Month	Period	Definition	Factor
June - September	Super-Peak	Hours Ending (HE) 13-20 Monday-Friday (except NERC holidays)	2.01
	Shoulder	HE 7-12, 21 and 22 Monday-Friday (except NERC holidays); HE 7-22 Saturday, Sunday and all NERC holidays	1.14
	Night	HE 1-6, 23 and 24 all days (including NERC holidays)	0.72
October - February	Super-Peak	Defined above	1.09
	Shoulder	Defined above	0.96
	Night	Defined above	0.78
March - May	Super-Peak	Defined above	1.13
	Shoulder	Defined above	0.86
	Night	Defined above	0.63

[55] PG&E 2008 RPS Solicitation, pro forma contract, pp. 30-31.
http://www.pge.com/includes/docs/word_xls/b2b/wholesaleelectricsuppliersolicitation/AttachmentGAsAvailableFormPPARev022908.DOC

Difference Between Feed-In Tariffs and other Renewable Programs

These tariffs are not available for facilities that have participated in the California Solar Initiative (CSI), Self-Generation Incentive Program (SGIP), Renewable Portfolio Standard (RPS) program or other ratepayer funded generation incentive program, including net metering tariffs.

Under the California Solar Initiative (CSI) and the Self Generation Incentive Program (SGIP), customers are offered upfront financial incentives to install solar, wind, and biogas generating capacity that can offset their customer load. Most customers that want to generate renewables that can offset their own usage will be better off using net-metering and our established incentive programs like the California Solar Initiative, due to the embedded financial incentive in net metering, and the fact that the incentive programs are designed to help customers offset the upfront capital expenditure of installations. Incentive programs are currently available for solar (California Solar Initiative) and biogas and wind (Self Generation Incentive Program). The feed-in tariffs also cover biomass and geothermal, for which there are no onsite generation incentive programs. Some customers may prefer a long-term contract at a fixed price over a financial incentive paid in the short term (under CSI for example) coupled with net metering.

Under the Renewable Portfolio Standard Program, the utilities are interested in signing contracts for renewable projects over 1.5 MW in size. The feed-in tariffs are intended for systems smaller than the RPS minimum contract size of 1.5 MW.

Table 6. Comparison of Various Renewable Programs

Column 1	Column 2	Column 3	Column 4	Column 5
	Feed-In Tariffs	California Solar Initiative	Self-Generation Incentive Program	Renewable Portfolio Standard Program
Open to all renewable resources	X			X
Open to solar facilities	X	X		X
Open to wind and biogas	X		X	X
Facilities over 1.5 MW in total system size		X Rebates only for first 1 MW of generation	X Rebates only for first 1 MW of generation	X
Facilities under 1.5 MW in system size	X	X	X	
Financial Incentives Available		X Solar Only	X Wind/Biogas Only	
Renewable Energy Credits transfer to utilities per contract terms	X ***			X
Renewable Energy Credits retained by system owner		X See .07-01-018	X D.05-05-011	
Customers able to use "net metering" tariffs		X	X	

*** = Renewable Energy Credits transfer to the utilities only for the energy sold to the utilities. If some energy is used onsite under the Net Sales approach, the applicable Renewable Energy Credits stay with the system owner.

Difference Between Feed-In Tariffs and Those Offered in Spain and Germany

These feed-in tariffs differ from the similarly named "feed-in tariffs" in Germany and Spain which include an incentive in the feed-in tariff price. Under the feed-in tariffs in California, customers are paid for the cost of generation based on the "market price referent". The price is based on the value of electrical generation, but is not intended to embed a subsidy or rebate in the price offering.

Interconnection

Interconnection may be accomplished using Commission-approved Rule 21, or FERC-Small Generator Interconnection Procedures (SGIP), as long as the process follows the principles of timely review and disposition, and does not present a barrier to project completion.

Last Modified: 1/20/2009

California Public Utilities Commission

Eligible Renewable Generation and Allocations

Eligible Renewable Generation

To qualify for the feed-in tariffs, the electric generation facility must be an eligible renewable energy resource as defined in PU Section 399.12. They cover all renewable generation technologies, including solar, wind, geothermal, biomass, biogas, small hydro and fuel cells that use renewable fuels.

These tariffs are intended for smaller installations, less then 1.5 MW in size, where the host is a retail customer of the utility, interconnected and operated in parallel with the utility's transmission and distribution system. These tariffs are intended for renewable electric generation that is not net metered and does not participate in Commission-adopted incentive programs such as the Self-Generation Incentive Program, the California Solar Initiative, or an interruptible load program, unless utility metering isolates the output of the Eligible Renewable Generating Facility from the output of any non-participating generator.

Allocations

The tariffs must be made available until the combined statewide cumulative rated capacity of eligible generation installed in water and wastewater facilities reaches 250 MW. The Commission's expansion of the program for non-water and –wastewater facilities includes an additional 228.447 MW of capacity, for a total of 478.447 MW in the program.

Table 2. Allocated Capacity per Utility

Electrical Corporation	Share of 2005 Coincident Peak Demand (%)	Water and Wastewater Capacity Allocation (MW)	Expanded Capacity Allocation – Non-water and –wastewater (MW)
SCE	49.538	123.844	123.844
PG&E	41.841	104.603	104.603
SDG&E	8.022	20.055	-
PacifiCorp	0.405	1.013	-
Sierra	0.162	0.404	-
BVES	0.031	0.077	-
MU	0.001	0.003	-
TOTAL	**100.00**	**250.000**	**228.447**

Last Modified: 1/20/2009

Pacific Gas and Electric Company

Brian K. Cherry
Vice President
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-7226

April 21, 2009

Advice 3410-E-A

(Pacific Gas and Electric Company ID U39 E)

Public Utilities Commission of the State of California

Subject: **Supplemental Filing for the Modifications to the Tariffs and Standard Contracts for the Purchase of Eligible Renewable Generation from Public Water and Wastewater Facilities and Small Renewable Generators**

Purpose:

Pacific Gas and Electric Company ("PG&E") hereby submits to the California Public Utilities Commission ("Commission" or "CPUC") a supplemental filing for Advice 3410-E dated January 27, 2009. The purpose of this supplement is to submit additional modifications to Form 79-1102, "Section 399.20 Power Purchase Agreement," and Form 79-1103, "Small Renewable Generator PPA," as follows:

- Update Section 3.2, which requires Sellers to register with the Western Renewable Energy Generating Information System ("WREGIS"), to reflect the fact that WREGIS is now operational.

- Address the issue that the California Climate Action Registry has been decommissioned and is no longer registering new projects.

- Clarify the "Termination Event" section.

In Attachment A, PG&E provides a chart detailing the modifications proposed in this supplemental filing as well as those changes originally proposed in Advice 3410-E.

Protests

Anyone wishing to protest this filing may do so by filing a protest with the CPUC and the Company by **May 11, 2009**, which is **20** days from the date of this filing. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. Protests should be mailed to:

CPUC Energy Division
Attention: Tariff Unit, 4th Floor
505 Van Ness Avenue
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: mas@cpuc.ca.gov and jnj@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4005 and Honesto Gatchalian, Energy Division, at the address shown above.

The protest also should be sent via U.S. mail (and by facsimile and electronically, if possible) to PG&E at the address shown below on the same date it is mailed or delivered to the Commission.

Pacific Gas and Electric Company
Attention: Brian Cherry
Vice President, Regulatory Relations
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-7226
E-Mail: PGETariffs@pge.com

Effective Date:

PG&E requests that this advice filing become effective on **January 27, 2009,** the same effective date as Advice Letter3410-E. PG&E submits this as a Tier 1 filing.

Notice:

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the service list for R.08-08-009. Address changes to the General Order 96-B service list should be directed to Rose De La Torre (415) 973-4716. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs.

Brian Cherry / [illegible]

Brian K. Cherry
Vice President - Regulatory Relations

cc: Service List for R.08-08-009
Karin Hieta, Energy Division
Jaclyn Marks, Energy Division

Attachments

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. **Pacific Gas and Electric Company (ID U39 M)**

Utility type:	Contact Person: David Poster
☑ ELC ☑ GAS	Phone #: (415) 973-1082
☐ PLC ☐ HEAT ☐ WATER	E-mail: Dxpu@pge.com

EXPLANATION OF UTILITY TYPE	(Date Filed/ Received Stamp by CPUC)
ELC = Electric GAS = Gas PLC = Pipeline HEAT = Heat WATER = Water	

Advice Letter (AL) #: **3410-E-A** **Tier:** [1]

Subject of AL: **Supplemental Filing for the Modifications to the Tariffs and Standard Contracts for the Purchase of Eligible Renewable Generation from Public Water and Wastewater Facilities and Small Renewable Generators**

Keywords (choose from CPUC listing): Forms

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other ____________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: E-4137

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL:

____

Resolution Required? ☐Yes ☑ No

Requested effective date: **1/27/2009** No. of tariff sheets: 4

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: Form 79-1102 and Form 79-1103

Service affected and changes proposed: N/A

Protests, dispositions, and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Tariff Files, Room 4005
DMS Branch
505 Van Ness Ave., San Francisco, CA 94102
jnj@cpuc.ca.gov and mas@cpuc.ca.gov

Pacific Gas and Electric Company
Attn: Brian K. Cherry, Vice President, Regulatory Relations
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

Attachment A
PG&E AL 3410-E-A: Summary of Proposed Changes

E-SRG Reference	E-PWF Reference	CURRENT LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARDCONTRACTS	PG&E's PROPOSED LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARD CONTRACTS
Proposed Modifications in Advice 3410-E-A			
PPA - Section 3.2 WREGIS	PPA - Section 3.2 WREGIS	3.2 WREGIS. Prior to the Initial Energy Delivery Date, Seller shall register the Facility in WREGIS and take all other actions necessary to ensure that the energy produced from the Facility is tracked for purposes of satisfying the California Renewables Portfolio Standard requirements, as may be amended or supplemented by the CPUC or CEC from time to time. In the event that WREGIs is not in operation as of the Initial Energy Delivery Date, Seller shall perform its obligations as required by this subsection as soon WREGIS is in operation.	3.2 WREGIS. Prior to the Initial Energy Delivery Date, Seller shall register the Facility in WREGIS and take all other actions necessary to ensure that the energy produced from the Facility is tracked for purposes of satisfying the California Renewables Portfolio Standard requirements, as may be amended or supplemented by the CPUC or CEC from time to time. Seller warrants that ~~all~~ it shall take all necessary steps ~~have been taken~~ to ~~allow~~ensure the ~~r~~Renewable ~~e~~Energy ~~c~~Credits transferred to Buyer under this Agreement are tracked in WREGIS and transferred in a timely manner to Buyer through WREGIS for purposes of satisfying Buyer's California Renewables Portfolio Standard Requirements, as may be amended or supplemented by the CPUC or CEC from time to time. ~~to be tracked in the Western Renewable Energy Generation Information System.~~
PPA – 10.2 Termination Event Section	PPA – 9.2 Termination Event Section	10.2 (E-SRG) and 9.2 (E-PWF) Termination Event. Buyer shall be entitled to terminate the Agreement upon the occurrence of any of the following, each of which is a "Termination Event": (a) The Facility has not achieved Commercial Operation within eighteen (18) months of the Execution Date of this Agreement; (b) Seller has not sold or delivered energy from the Facility to PG&E for a period of twelve (12) consecutive months; (c) All the Agreements whose combined capacity fill PG&E's proportionate share as determined by PUC Section 399.20 are operational; or (d) Seller breaches its covenant to maintain its status as an ERR as set forth in Section 4.3.2. of the Agreement.	10.2 Termination Event. Buyer shall be entitled to terminate the Agreement upon the occurrence of any of the following, each of which is a "Termination Event": (a) The Facility has not achieved Commercial Operation within eighteen (18) months of the Execution Date of this Agreement; (b) Seller has not sold or delivered energy from the Facility to PG&E for a period of twelve (12) consecutive months; ~~(c) All the Agreements whose combined capacity fill PG&E's proportionate share as determined by PUC Section 399.20 are operational; or~~ (c) Seller breaches its covenant to maintain its status as an ERR as set forth in Section 4.3.2. of the Agreement.
PPA - Climate Action	PPA - Climate Action	(iii) the Facility is registered with the California Climate Action Registry as provided in Section 5.8. As evidence of the Initial Energy Delivery Date, the Parties shall execute and	~~(iii) the Facility is registered with the California Climate Action Registry as provided in Section 5.8.~~ As evidence of the Initial Energy Delivery Date, the Parties shall execute and exchange

E-SRG Reference	E-PWF Reference	CURRENT LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARDCONTRACTS	PG&E's PROPOSED LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARD CONTRACTS
Registry Section	Registry Section	exchange the "Initial Energy Delivery Date Confirmation Letter" attached hereto as Appendix B on the Initial Energy Delivery Date. 5.8 (E-SRG) 4.11 (E-PWF)Climate Action Registry. Seller shall register the Facility with the California Climate Action Registry as may be required by the CPUC pursuant to CPUC D. 06-02-032 and any subsequent order, but in any event, no later than the Initial Energy Delivery Date. Seller shall report greenhouse gas emissions output from the Facility if PG&E so requests. Seller shall be liable for all reasonable expenses PG&E incurs resulting from Seller's failure to comply with this provision to the extent that PG&E must estimate greenhouse gas emissions and report these emissions in satisfaction of certain legal or regulatory requirements.	the "Initial Energy Delivery Date Confirmation Letter" attached hereto as Appendix B on the Initial Energy Delivery Date. [Replace Section 5.8 with:] 5.8/4.11 Greenhouse Gas Emissions: During the Term, Seller acknowledges that a Governmental Authority may require Buyer to take certain actions with respect to greenhouse gas emissions *attributable to the generation of Energy*, including, but not limited to, reporting, registering, tracking, allocating for or accounting for such emissions. Promptly following Buyer's written request, Seller agrees to take all commercially reasonable actions and execute or provide any and all documents, information or instruments *with respect to generation by the Project* reasonably necessary to permit Buyer to comply with such requirements, if any.
Proposed Modifications in Advice 3410-E			
Tariff and PPA – MPR and TOD Section	Tariff and PPA – MPR and TOD Section	Replace 2007 MPR and TOD factors with 2008 MPR and TOD factors	Replace 2007 MPR and TOD factors with 2008 MPR and TOD factors
Tariff – Applicability Section	Tariff – Applicability Section	APPLICABILITY: This Schedule is optional for customers who meet the definition of an Eligible Public Water Facility or Eligible Public Wastewater Facility and own an Eligible Renewable Energy Resource as defined in the Special Conditions section of this Schedule, with a total effective generation capacity of not more than 1.5 megawatts. Service under this Schedule is on a first-come-first-served basis and shall be closed to new customers once the combined rated generating capacity of Eligible Renewable Energy Resource within PG&E's service territory reaches 104.603 megawatts, as set forth in D. 07-07-027, effective July 26, 2007.	APPLICABILITY: This Schedule is optional for customers who meet the definition of an Eligible Public Water Facility or Eligible Public Wastewater Facility and own an Eligible Renewable Energy Resource as defined in the Special Conditions section of this Schedule, with a total effective generation capacity of not more than 1.5 megawatts. Service under this Schedule is on a first-come-first-served basis and shall be closed to new customers once the combined rated generating capacity of Eligible Renewable Energy Resource within PG&E's service territory reaches 104.603 megawatts, as set forth in D. 07-07-027, effective July 26, 2007. An electric generation facility must meet the criteria listed in Public Utilities Code section 399.20(b) as follows: (1) Has an effective capacity of not more than one and one-half megawatts and is located on property owned or under the control of the customer. (2) Is interconnected and operates in parallel with the electric

E-SRG Reference	E-PWF Reference	CURRENT LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARDCONTRACTS	PG&E's PROPOSED LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARD CONTRACTS
			transmission and distribution grid. (3) Is strategically located and interconnected to the electric transmission system in a manner that optimizes the deliverability of electricity generated at the facility to load centers.
Tariff – Special Conditions Section	Tariff – Special Conditions Section	2. Participation in other PG&E Programs: As set forth in Decision 07-07-027, customers taking service under this Schedule may not obtain benefits from both this Schedule and the Self-Generation Incentive Program, net metering programs, the California Solar Initiative, or other similar programs.	2. Participation in other PG&E Programs: As set forth in Decision 07-07-027, customers taking service under this Schedule may not obtain benefits from both this Schedule and the Self-Generation Incentive Program, net energy metering programs, the California Solar Initiative, or other similar programs.
Not Applicable	Tariff – Special Conditions Section	3. Definitions: The following definitions are applicable to service provided under this Schedule. a. Eligible Wastewater Facility - Any facility owned by a state, local, or federal agency and used in the treatment or reclamation of sewage and industrial wastes, and located on property owned or under the control of the public water or wastewater agency.	3. Definitions: The following definitions are applicable to service provided under this Schedule. a. Eligible Public Wastewater Facility - Any facility owned by a state, local, or federal agency and used in the treatment or reclamation of sewage and industrial wastes, and located on property owned or under the control of the public water or wastewater agency.
Tariff – Special Conditions Section	Tariff – Special Conditions Section	A definition for effective capacity was not previously included in the tariff.	d. Effective Capacity – The capacity of the eligible renewable generator as established by the manufacturer that is available for use either at-site to meet customer load or exported to the grid for sale to PG&E under the Section 399.20 PPA. PG&E will use either the nameplate rating of the eligible renewable generator if no inverter is used, or the inverter rating if the generator is inverter based.
PPA – Sections 2.1.7 and 2.1.8 under Seller's Generating Facility, Purchase Prices and Payment Section	PPA – Sections 2.1.7 and 2.1.8 under Seller's Generating Facility, Purchase Prices and Payment Section	This information was not previously included in the PPA.	2.1.7 A description of the Facility, including a summary of its significant components, a drawing showing the general arrangements of the Facility, and a single line diagram illustrating the interconnection of the Facility and loads with PG&E's electric distribution system, is attached and incorporated herein as Appendix E. 2.1.8 The name and address PG&E uses to locate the electric service account(s) and premises used to interconnect the Facility with PG&E's distribution systems is: ____________________

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PPA – Section 2.7 No Additional Incentives	PPA – Section 2.7 No Additional Incentives	2.7 No Additional Incentives. Seller agrees that during the Term of this Agreement, Seller shall not seek additional compensation or other benefits pursuant to the Self-Generation Incentive Program, as defined in CPUC Decision ("D.") 01-03-073, the California Solar Initiative, as defined in CPUC D.06-01-024, PG&E's net metering tariff, or other similar California ratepayer subsidized program relating to energy production with respect to the Facility.	2.7 No Additional Incentives. Seller agrees that during the Term of this Agreement, Seller shall not seek additional compensation or other benefits pursuant to the Self-Generation Incentive Program, as defined in CPUC Decision ("D.") 01-03-073, the California Solar Initiative, as defined in CPUC D.06-01-024, PG&E's net energy metering tariff, or other similar California ratepayer subsidized program relating to energy production with respect to the Facility.
PPA – Appendix C TOD Factors Section	PPA – Appendix C TOD Factors Section	**Appendix C** **Time of Delivery (TOD) Periods & Factors** Definitions: 1. Super-Peak (5x8) = HE (Hours Ending) 13 - 20, Monday - Friday (*except* NERC holidays). 2. Shoulder = HE 7 - 12, 21 and 22, Monday - Friday (*except* NERC holidays); and HE 7 - 22 Saturday, Sunday and *all* NERC holidays. 3. Night (7x8) = HE 1 - 6, 23 and 24 all days (*including* NERC holidays). 4. NERC (Additional Off-Peak) Holiday include: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Three of these days, Memorial Day, Labor Day, and Thanksgiving Day occur on the same day each year. Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the 4th Thursday in November. New Year's Day, Independence Day, and Christmas Day, by definition, are predetermined dates each year. However, in the event they occur on a Sunday, the "NERC Additional Off-Peak Holiday" is celebrated on the Monday immediately following that Sunday. However, if any of these days occur on a Saturday, the "NERC Additional Off-Peak Holiday" remains on that Saturday.	**Appendix C** **Time of Delivery (TOD) Periods & Factors** Definitions: 2. Super-Peak (5x8) = HE (Hours Ending) 13 – 20 (Pacific Prevailing Time (PPT)), Monday - Friday (*except* NERC holidays) in the applicable Monthly Period. 2. Shoulder = HE 7 - 12, 21 and 22 PPT Monday - Friday (*except* NERC holidays); and HE 7 - 22 PPT Saturday, Sunday and *all* NERC holidays in the applicable Monthly Period. 3. Night (7x8) = HE 1 - 6, 23 and 24 PPT all days (*including* NERC holidays) in the applicable Monthly Period. ~~4.~~ "NERC ~~(Additional Off-Peak)~~Holidays" mean the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Three of these days, Memorial Day, Labor Day, and Thanksgiving Day occur on the same day each year. Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the 4th Thursday in November. New Year's Day, Independence Day, and Christmas Day, by definition, are predetermined dates each year. However, in the event they occur on a Sunday, the "NERC ~~Additional Off-Peak~~ Holiday" is celebrated on the Monday immediately following that Sunday. However, if any of these days occur on a Saturday, the "NERC ~~Additional Off-Peak~~ Holiday" remains on that Saturday.

E-SRG Reference	E-PWF Reference	CURRENT LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARDCONTRACTS	PG&E's PROPOSED LANGUAGE IN THE E-SRG/E-PWF TARIFFS/STANDARD CONTRACTS
PPA Appendix D Section B Forecasting Requirements	PPA Appendix D Section B Forecasting Requirements	(b) Generating Facilities 100 kW and greater must provide a weekly forecast of their expected generation output or commit to a default schedule. 2. Weekly Energy Forecasting Procedures. Seller must meet all of the following requirements specified below: Beginning the Wednesday prior to the planned Initial Operation of the Generating Facility, Seller will electronically provide PG&E with an Energy Forecast for the next calendar week, by no later than 5 PM Wednesday of the week preceding the week covered by the Energy Forecast. The Weekly Energy Forecast submitted to PG&E shall: a) Not include any anticipated or expected electric energy losses; b) Be constructed using an excel file format and naming convention provided by PG&E; c) Include Seller's contact information; d) Be sent to QFSchedules@PG&E.com or as otherwise instructed by PG&E; e) Limit Day Ahead forecast changes to no less than 500 kW.	(b) Generating Facilities 100 kW and greater must provide a weekly forecast of their expected generation output ~~or commit to a default schedule~~. 2. Weekly Energy Forecasting Procedures. Seller must meet all of the following requirements specified below: Beginning the Wednesday prior to the planned Initial Operation of the Generating Facility, Seller will electronically provide PG&E with an Energy Forecast for the next calendar week, by no later than 5 PM Wednesday of the week preceding the week covered by the Energy Forecast. The Weekly Energy Forecast submitted to PG&E shall: a) Not include any anticipated or expected electric energy losses; b) Be ~~constructed using an excel file format and naming convention provided by PG&E~~ using PG&E's website at https://www.pge.com/qic with Login and password information to be provided, or as otherwise instructed by PG&E; c) Include Seller's contact information; ~~d) Be sent to QFSchedules@PG&E.com or as otherwise instructed by PG&E;~~ ~~e~~d) Limit Day Ahead forecast changes to no less than 1~~5~~00 kW.

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
28296-E	Electric Sample Form No. 79-1102 Section 399.20 Power Purchase Agreement	26841-E
28297-E	Electric Sample Form No. 79-1103 Small Renewable Generator PPA	26847-E
28298-E	ELECTRIC TABLE OF CONTENTS Sheet 1	28263-E
28299-E	ELECTRIC TABLE OF CONTENTS SAMPLE FORMS Sheet 17	27824-E

Electric Sample Form No. 79-1102
Section 399.20 Power Purchase Agreement

Please Refer to Attached Sample Form

SECTION 399.20

POWER PURCHASE AGREEMENT

BETWEEN

_______________________________________ AND

PACIFIC GAS AND ELECTRIC COMPANY

PACIFIC GAS AND ELECTRIC COMPANY, a California Corporation ("PG&E" or "Buyer"), and ________________________ ("Seller") hereby enter into this Power Purchase Agreement ("Agreement"). Seller and PG&E are sometimes referred to in this Agreement jointly as "Parties" or individually as "Party." In consideration of the mutual promises and obligations stated in this Agreement and its appendices, the Parties agree as follows:

1. DOCUMENTS INCLUDED; DEFINED TERMS

This Agreement includes the following appendices, which are specifically incorporated herein and made a part of this Agreement.

Appendix A- Definitions

Appendix B- Initial Energy Delivery Date Confirmation Letter

Appendix C- Time of Delivery ("TOD") Periods and Factors

Appendix D- Counterparty Notification Requirements for Outage and Generation Schedule Changes

2. SELLER'S GENERATING FACILITY, PURCHASE PRICES AND PAYMENT

2.1 Facility. This Agreement governs PG&E's purchase of energy and capacity from the electrical generating facility (hereinafter referred to as the "Facility" or "Unit") as described in this Section.

2.1.1 The Facility is located at _________________ in _________ County, California.

2.1.2 The Facility is described as ____________________________.

2.1.3 The Facility's primary fuel is _______ [i.e. biogas, hydro, etc.].

2.1.4 The Facility has a nameplate rating of ___ kilowatts ("kW"), at unity power factor at 60 degrees Fahrenheit at sea level and has a primary voltage level of ____ kilovolts ("kV"). Seller shall not modify the Facility to increase the nameplate rating without the prior written consent of PG&E.

2.1.5 The Facility is connected to the PG&E electric system at _____ kV.

2.1.6 If not already capable of delivering energy on the Execution Date, the Facility's scheduled Commercial Operation Date is ________________.

2.1.7 A description of the Facility, including a summary of its significant components, a drawing showing the general arrangements of the Facility, and a single line diagram illustrating the interconnection of the Facility and loads with PG&E's electric distribution system, is attached and incorporated herein as Appendix E.

2.1.8 The name and address PG&E uses to locate the electric service account(s) and premises used to interconnect the Facility with PG&E's distribution systems is:

____

____

____

____

2.2 Transaction. During the Delivery Term of this Agreement, as provided in Section 2.3, Seller shall sell and deliver, or cause to be delivered, and PG&E shall purchase and receive, or cause to be received, energy produced by and capacity provided from the Facility, up to 1500 kW, at the Delivery Point, as defined pursuant to Section 5.1, pursuant to Seller's election of a (check one) ☐ full buy/sell or ☐ excess sale arrangement as described in paragraphs 2.2.1 and 2.2.2 below. PG&E shall pay Seller the Contract Price, set forth in Section 2.4, in accordance with the terms hereof. In no event shall Seller have the right to procure the energy or capacity from sources other than the Facility for sale or delivery to PG&E under this Agreement or substitute such energy or capacity. PG&E shall have no obligation to receive or purchase energy or capacity from Seller prior to the Initial Energy Delivery Date, as defined in Section 2.3, or after the end of the Delivery Term, as defined in Section 2.3. The Parties agree that the execution and performance of the Parties under this Agreement shall satisfy PG&E's obligations, if any, under the Public Utility Regulatory Policies Act and its implementing regulations, i.e., 18 C.F.R. §§ 292.303.

2.2.1 Full Buy/Sell. Seller agrees to sell to PG&E the Facility's gross output in kilowatt-hours, net of Station Use and transformation and transmission losses to the Delivery Point into the PG&E system, together with all Green Attributes and Resource Adequacy Benefits. Seller shall purchase all energy required to serve the Facility's on-site load, net of station use, from PG&E pursuant to PG&E's applicable retail rate schedule.

2.2.2 Excess Sale. Seller agrees to sell to PG&E the Facility's gross output in kilowatt-hours, net of Station Use and any on-site use by Seller and transformation and transmission losses to the Delivery Point into the PG&E system. Seller agrees to convey to PG&E all Green Attributes and Resource Adequacy Benefits associated with the energy sold to PG&E.

2.3 Delivery Term. The Seller shall deliver the energy and capacity from the Facility to PG&E for a period of (check one) ☐ ten (10), ☐ fifteen (15), or ☐ twenty (20) Contract Years ("Delivery Term"), which shall commence on the first date on which energy is delivered from the Facility to PG&E ("Initial Energy Delivery Date") under this Agreement and continue until the end of the last Contract Year unless terminated by the terms of this Agreement. The Initial Energy Delivery Date shall occur only when all of the following conditions have been satisfied:

(i) the Commercial Operation Date has occurred, if the Facility was not in operation prior to the Execution Date of this Agreement;

(ii) the Facility's status as an Eligible Renewable Energy Resource, is demonstrated by Seller's receipt of certification from the CEC and is registered in WREGIS; and

(iii) as evidence of the Initial Energy Delivery Date, the Parties shall execute and exchange the "Initial Energy Delivery Date Confirmation Letter" attached hereto as Appendix B on the Initial Energy Delivery Date.

2.4 Contract Price. Once both Parties have executed this Agreement PG&E shall pay Seller for each megawatt-hour ("MWh") of energy and associated capacity delivered to PG&E during each Contract Year for the Delivery Term at the applicable Market Price Referent specified below for the Facility's actual Commercial Operation Date. Payment shall be adjusted by the appropriate Time of Delivery ("TOD") factor listed in Appendix C.

Adopted 2008 Market Price Referents[1] (Nominal - dollars/kWh)			
Resource Type	**10-Year**	**15-Year**	**20-Year**
2009 Baseload MPR	0.10043	0.10537	0.11126
2010 Baseload MPR	0.10175	0.10748	0.11390
2011 Baseload MPR	0.10400	0.11046	0.11730
2012 Baseload MPR	0.10698	0.11405	0.12126
2013 Baseload MPR	0.10998	0.11776	0.12527
2014 Baseload MPR	0.11278	0.12122	0.12897
2015 Baseload MPR	0.11605	0.12503	0.13290
2016 Baseload MPR	0.11971	0.12915	0.13706
2017 Baseload MPR	0.12367	0.13352	0.14144
2018 Baseload MPR	0.12802	0.13814	0.14603
2019 Baseload MPR	0.13271	0.14298	0.15080
2020 Baseload MPR	0.13776	0.14797	0.15578

[1] Note: Using 2009 as the base year, Staff calculates MPRs for 2009-2020 that reflect different project online dates. Link to 2008 MPR Model: http://www.ethree.com/MPR.html

2.5 Billing. PG&E shall pay Seller by check or Automated Clearing House transfer within approximately 30 days of the meter reading date if the value of the purchased energy in a month is at least fifty dollars ($50); if less, PG&E may pay Seller quarterly. PG&E shall have the right, but not the obligation, to read the Facility's meter on a daily basis.

2.6 Title and Risk of Loss. Title to and risk of loss related to the energy produced from and capacity provided by the Facility shall transfer from Seller to PG&E at the Delivery Point. Seller warrants that it will deliver to PG&E all energy and capacity from the Facility free and clear of all liens, security interests, claims and encumbrances or any interest therein or thereto by any person arising prior to the Delivery Point.

2.7 No Additional Incentives. Seller agrees that during the Term of this Agreement, Seller shall not seek additional compensation or other benefits pursuant to the Self-Generation Incentive Program, as defined in CPUC Decision ("D.") 01-03-073, the California Solar Initiative, as defined in CPUC D.06-01-024, PG&E's net energy metering tariff, or other similar California ratepayer subsidized program relating to energy production with respect to the Facility.

2.8 Private Energy Producer. Seller agrees to provide to Buyer copies of each of the documents identified in PUC Section 2821(d)(1), if applicable, as may be amended from time to time, as evidence of Seller's compliance with such PUC section. Such documentation shall be provided to Buyer within thirty (30) days of Seller's receipt of written request therefor.

3. GREEN ATTRIBUTES; RESOURCE ADEQUACY BENEFITS

3.1 Conveyance of Green Attributes. Seller provides and conveys all Green Attributes from the Facility to Buyer as part of the Product (energy and capacity) delivered to Buyer for the duration of the Delivery Term. Seller represents and warrants that Seller holds the rights to all Green Attributes from the Facility, and Seller agrees to convey and hereby conveys all such Green Attributes to Buyer as included in the delivery of the Product from the Facility. Further, "Green Attributes" also means any and all credits that satisfy the requirement to procure electricity from ERRs, pursuant to the California Renewables Portfolio Standard, that are directly attributable to electric production from the Facility. Seller represents that the energy, capacity, ancillary services and Green Attributes from the Facility have not been, nor will be, sold or used to satisfy any obligation other than PG&E's California Renewables Portfolio Standard obligation.

3.2 WREGIS. Prior to the Initial Energy Delivery Date, Seller shall register the Facility in WREGIS and take all other actions necessary to ensure that the energy produced from the Facility is tracked for purposes of satisfying the California Renewables Portfolio Standard requirements, as may be amended or supplemented by the CPUC or CEC from time to time. Seller warrants that it shall take all necessary steps to ensure the Renewable Energy Credits transferred to Buyer under this Agreement are tracked in WREGIS and transferred in a timely manner to Buyer through WREGIS for purposes of satisfying Buyer's California Renewables Portfolio Standard Requirements, as may be amended or supplemented by the CPUC or CEC from time to time.

3.3 Resource Adequacy Benefits. In accordance with PUC Section 399.20(g), Seller conveys to PG&E all Resource Adequacy Benefits attributable to the physical generating capacity of Seller's Facility to enable PG&E to count such capacity towards PG&E's resource adequacy requirement for purposes of PUC Section 380. Seller shall take all reasonable actions and execute documents and instructions necessary to enable Buyer to secure Resource Adequacy Benefits; Seller shall comply with all applicable reporting requirements.

4. REPRESENTATION AND WARRANTIES; COVENANTS

4.1 Representations and Warranties. On the Execution Date, each Party represents and warrants to the other Party that:

4.1.1 it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

4.1.2 the execution, delivery and performance of this Agreement is within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

4.1.3 this Agreement and each other document executed and delivered in accordance with this Agreement constitutes its legally valid and binding obligation enforceable against it in accordance with its terms;

4.1.4 it is not bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming bankrupt;

4.1.5 there is not pending or, to its knowledge, threatened against it or any of its affiliates any legal proceedings that could materially adversely affect its ability to perform its obligations under this Agreement; and

4.1.6 it is acting for its own account, has made its own independent decision to enter into this Agreement and as to whether this Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing the merits of, and understands and accepts, the terms, conditions and risks of this Agreement.

4.2 General Covenants. Each Party covenants that throughout the Term of this Agreement:

4.2.1 it shall continue to be duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

4.2.2 it shall maintain (or obtain from time to time as required, including through renewal, as applicable) all regulatory authorizations necessary for it to legally perform its obligations under this Agreement; and

4.2.3 it shall perform its obligations under this Agreement in a manner that does not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it.

4.3 Seller Representation and Warranty and Covenant.

4.3.1 Representation and Warranty. In addition to the representations and warranties specified in Section 4.1, Seller makes the following additional representations and warranties as of the Execution Date:

(a) Seller's Facility is (check one) ☐ a facility owned by a state, local, or federal agency and used in the treatment or reclamation of sewage and industrial wastes; or ☐ a facility owned by a state, local, or federal agency that develops, stores, distributes or supplies water.

(b) Seller has not received an incentive under the Self-Generation Incentive Program, as defined in CPUC D.01-03-073, or the California Solar Initiative, as defined in CPUC D.06-01-024.

(c) Seller's execution of this Agreement will not violate PUC Section 2821(d)(1) if applicable.

4.3.2 Covenant. Seller hereby covenants that throughout the Term of the Agreement, the Facility is, or will qualify prior to the Initial Energy Delivery Date, as an ERR, specifically, Seller and, if applicable, its successors, represents and warrants throughout the term of the Delivery Term of each Transaction entered into under this Agreement that: (a) the Unit(s) qualifies and is certified by the CEC as an Eligible Renewable Energy Resource; and (b) the Unit(s) output delivered to Buyer qualifies under the requirements of the California Renewables Portfolio Standard. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

GENERAL CONDITIONS

4.4 Facility Care, Interconnection and Transmission Service. If PG&E does not deem Seller's existing interconnection service, equipment and agreement satisfactory for the delivery of energy under this Agreement, Seller shall execute a Small Generator Interconnection Agreement with PG&E's Generation Interconnection Services Department and pay and be responsible for designing, installing, operating, and maintaining the Facility in accordance with all applicable laws and regulations and shall comply with all applicable PG&E, CAISO, CPUC and FERC tariff provisions, including applicable interconnection and metering requirements. Seller shall also comply with any modifications, amendments or additions to the applicable tariff and protocols. During the Delivery Term, Seller shall arrange and pay independently for any and all necessary costs under any interconnection agreement with PG&E. To make deliveries to PG&E, Seller must maintain an interconnection agreement with PG&E in full force and effect.

4.5 Metering Requirements. Seller shall comply with all applicable rules in installing a meter appropriate for deliveries pursuant to the Full Buy/Sell or Excess Sale arrangement selected in paragraph 2.2, above, which can be electronically read daily by: (a) a telephone and modem; (b) an analog or digital phone connection; or (c) an internet portal address for PG&E's Energy Data Services ("EDS"). Seller shall be responsible for procuring and maintaining the communication link to electronically retrieve this metering data.

4.6 Standard of Care. Seller shall: (a) maintain and operate the Facility and Interconnection Facilities, except facilities installed by PG&E, in conformance with all applicable laws and regulations and in accordance with Good Utility Practices, as defined by PG&E's Wholesale Distribution Tariff and the CAISO Tariff, as they may be amended, supplemented or replaced (in whole or in part) from time to time; (b) obtain any governmental authorizations and permits required for the construction and operation thereof; and (c) generate, schedule and perform transmission services in compliance with all applicable operating policies, criteria, rules, guidelines and tariffs and Good Utility Practices, as provided in clause (a) above. Seller shall reimburse PG&E for any and all losses, damages, claims, penalties, or liability PG&E incurs as a result of Seller's failure to obtain or maintain any governmental authorizations and permits required for construction and operation of the Facility throughout the Term of this Agreement.

4.7 Access Rights. PG&E, its authorized agents, employees and inspectors shall have the right to inspect the Facility on reasonable advance notice during normal business hours and for any purposes reasonably connected with this Agreement or the exercise of any and all rights secured to PG&E by law, or its tariff schedules, PG&E Interconnection Handbook and rules on file with the CPUC. PG&E shall make reasonable efforts to coordinate its emergency activities with the Safety and Security Departments, if any, of the Facility operator. Seller shall keep PG&E advised of current procedures for communicating with the Facility operator's Safety and Security Departments.

4.8 Protection of Property. Each Party shall be responsible for protecting its own facilities from possible damage resulting from electrical disturbances or faults caused by the operation, faulty operation, or non-operation of the other Party's facilities and such other Party shall not be liable for any such damages so caused.

4.9 PG&E Performance Excuse; Seller Curtailment.

4.9.1 PG&E Performance Excuse. PG&E shall not be obligated to accept or pay for energy produced by or capacity provided from the Facility during a Dispatch Down Period, or Force Majeure, as defined in Appendix A.

4.9.2 Seller Curtailment. PG&E may require Seller to interrupt or reduce deliveries of energy: (a) when necessary to construct, install, maintain, repair, replace, remove, or investigate any of its equipment or part of PG&E's transmission system or distribution system or facilities; or (b) if PG&E or the CAISO determines that curtailment, interruption, or reduction is necessary because of a System Emergency, as defined in the CAISO Tariff, Forced Outage, Force Majeure as defined in Appendix A, or compliance with Good Utility Practice, as such term is defined in the CAISO Tariff.

4.10 Notices of Outages. Whenever possible, PG&E shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries may be required.

4.11 Greenhouse Gas Emissions: During the Term, Seller acknowledges that a Governmental Authority may require Buyer to take certain actions with respect to greenhouse gas emissions *attributable to the generation of Energy*, including, but not limited to, reporting, registering, tracking, allocating for or accounting for such emissions. Promptly following Buyer's written request, Seller agrees to take all commercially reasonable actions and execute or provide any and all documents, information or instruments *with respect to generation by the Project* reasonably necessary to permit Buyer to comply with such requirements, if any.

5. INDEMNITY

Each Party as indemnitor shall save harmless and indemnify the other Party and the directors, officers, and employees of such other Party against and from any and all loss and liability for injuries to persons including employees of either Party, and damages, including property of either Party, resulting from or arising out of: (a) the engineering, design, construction, maintenance, or operation of; or (b) the installation of replacements, additions, or betterments to the indemnitor's facilities. This indemnity and save harmless provision shall apply notwithstanding the active or passive negligence of the indemnitee. Neither Party shall be indemnified for liability or loss, resulting from its sole negligence or willful misconduct. The indemnitor shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity and shall pay all costs, including reasonable attorney fees that may be incurred by the other Party in enforcing this indemnity.

6. LIMITATION OF DAMAGES

EXCEPT AS OTHERWISE PROVIDED IN THIS AGREEMENT THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY

AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED UNLESS EXPRESSLY HEREIN PROVIDED. NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. UNLESS EXPRESSLY HEREIN PROVIDED, AND SUBJECT TO THE PROVISIONS OF SECTION 6 (INDEMNITY), IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE.

7. NOTICES

Notices shall, unless otherwise specified herein, be in writing and may be delivered by hand delivery, United States mail, overnight courier service, facsimile or electronic messaging (e-mail). Whenever this Agreement requires or permits delivery of a "notice" (or requires a Party to "notify"), the Party with such right or obligation shall provide a written communication in the manner specified below. A notice sent by facsimile transmission or e-mail will be recognized and shall be deemed received on the Business Day on which such notice was transmitted if received before 5 p.m. Pacific prevailing time (and if received after 5 p.m., on the next Business Day) and a notice by overnight mail or courier shall be deemed to have been received two (2) Business Days after it was sent or such earlier time as is confirmed by the receiving Party unless it confirms a prior oral communication, in which case any such notice shall be deemed received on the day sent. A Party may change its addresses by providing notice of same in accordance with this provision. All written notices shall be directed as follows:

TO PG&E:	Pacific Gas and Electric Company Attention: Manager, Contract Management 245 Market Street, Mail Code N12E San Francisco, CA 94177-0001
TO SELLER:	____________ ____________ ____________ ____________

8. INSURANCE

8.1 General Liability Coverage.

8.1.1 Seller shall maintain during the performance hereof, General Liability Insurance[2] of not less than $1,000,000 if the Facility's nameplate is over 100 kW, $500,000 if the nameplate rating of the Facility is over 20 kW to 100kW or $100,000 if the nameplate rate of the Facility is 20 kW or below of combined single limit or equivalent for bodily injury, personal injury, and property damage as the result of any one occurrence.

8.1.2 General Liability Insurance shall include coverage for Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations.

8.1.3 Such insurance shall provide for thirty (30) days written notice to PG&E prior to cancellation, termination, alteration, or material change of such insurance.

8.2 Additional Insurance Provisions.

8.2.1 Evidence of coverage described above in Paragraph 9.1 shall state that coverage provided in primary and is not excess to or contributing with any insurance or self-insurance maintained by PG&E.

8.2.2 PG&E shall have the right to inspect or obtain a copy of the original policy(ies) of insurance.

8.2.3 Seller shall furnish the required certificates and endorsements to PG&E prior to commencing operation.

8.2.4 All insurance certificates, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

Pacific Gas and Electric Company
Attention: Manager, Insurance Department
77 Beale Street, Room E280
San Francisco, CA 94105

9. TERM, DEFAULT, TERMINATON EVENT AND TERMINATION

9.1 Term. The term of this Agreement shall commence upon the later of: (i) execution by the duly authorized representatives of each of PG&E and Seller; or (ii) when PG&E notifies Seller that PG&E can accommodate Seller's Facility in PG&E's

[2] Governmental agencies which have an established record of self-insurance may provide the required coverage through self-insurance.

proportionate share of the statewide cumulative total of 250 MW as specified in PUC Section 399.20(e), and shall remain in effect until the conclusion of the Delivery Term or unless terminated sooner pursuant to Section 10.3 of this Agreement (the "Term"). All indemnity rights shall survive the termination of this Agreement for twelve (12) months.

9.2 Termination Event. Buyer shall be entitled to terminate the Agreement upon the occurrence of any of the following, each of which is a "Termination Event":

(a) The Facility has not achieved Commercial Operation within eighteen (18) months of the Execution Date of this Agreement;

(b) Seller has not sold or delivered energy from the Facility to PG&E for a period of twelve (12) consecutive months;

(c) Seller breaches its covenant to maintain its status as an ERR as set forth in Section 4.3.2. of the Agreement.

9.3 Termination.

9.3.1 Declaration of a Termination Event. If a Termination Event has occurred and is continuing, Buyer shall have the right to: (a) send notice, designating a day, no earlier than five days after such notice is deemed to be received (as provided in Section 8) and no later than 20 days after such notice is deemed to be received (as provided in Section 8), as an early termination date of this Agreement ("Early Termination Date") unless Seller has timely communicated with Buyer and the Parties have agreed to resolve the circumstances giving rise to the termination Event; (b) accelerate all amounts owing between the Parties; and (c) terminate this Agreement and end the Delivery Term effective as of the Early Termination Date.

9.3.2 Release of Liability for Termination Event. Upon termination of this Agreement pursuant to Section 10.3.1, neither Party shall be under any further obligation or subject to liability hereunder, except with respect to the indemnity provision in Section 6 hereof, which shall remain in effect for a period of 12 months following the Early Termination Date.

10. SCHEDULING

11.1 Scheduling Obligations. PG&E shall be Seller's designated Scheduling Coordinator (as defined by CAISO tariff). PG&E will schedule Seller' project using Prudent Utility Practices and Seller shall employ Prudent Utility Practices and exercise reasonable efforts to operate and maintain its project. All generation interconnection and scheduling services shall be performed in accordance with all applicable operating policies, criteria, guidelines and tariffs of the CAISO or its successor, and any other generally accepted operational requirements. Seller, at its own expense, shall be responsible for complying with all applicable contractual, metering and interconnection requirements. Seller shall promptly notify PG&E of significant (i.e., greater than 100 kW) changes to its energy schedules using PG&E's web site (see Appendix D). Seller will exercise reasonable efforts to comply with conditions that might arise if the CAISO modifies or amends its tariffs, standards, requirements, and/or protocols in the future.

11.2 CAISO Charges.

11.2.1 CAISO Charge Obligations. PG&E and Seller shall cooperate to minimize CAISO delivery imbalances and any resulting fees, liabilities, assessments or similar charges assessed by the CAISO ("CAISO Charges") to the extent possible, and shall each promptly notify the other as soon as possible of any material loss of system capability, deviation or imbalance that is occurring or has occurred. Seller shall reimburse PG&E for any CAISO Charges PG&E incurs as a result of Seller's loss of system capability, deviation or imbalance. Any such CAISO Charges reimbursable to PG&E shall be limited to the period until the commencement of the next settlement period following Seller's notification for which the delivery schedule can be adjusted. Notwithstanding anything to the contrary herein, in the event Seller makes a change to its schedule on the actual date and time of delivery for any reason (other than an adjustment imposed by CAISO) which results in differences between the project's actual generation and the scheduled generation (whether in part or in whole), Seller shall use reasonable efforts to notify PG&E. PG&E will make commercially reasonable efforts to accommodate Seller's changes and mitigate any imbalance penalties or charges levied for such changes.

11.2.2 CAISO Penalties. Seller shall be responsible for any "non-Performance Penalties" assessed to PG&E by the CAISO ("CAISO Penalties"), under the CAISO Tariff Enforcement Protocol, and not due to any fault of PG&E, which shall include, without limitation, any deviation, imbalance or uninstructed energy charges or penalties payable to the CAISO that are due to the fault of Seller. To the extent that Seller materially deviates from its energy schedules (other than an adjustment imposed by the CAISO, a deviation due to any fault of PG&E, or an excused Seller failure to deliver, whether for reasons of Force Majeure or otherwise), and such departure results in CAISO Penalties being assessed to PG&E, such CAISO Penalties shall be passed on to Seller. Any such CAISO Penalties passed on to Seller shall be limited to the period until the commencement of the next settlement period following Seller's notification (as described above) for which the delivery schedule can be adjusted.

11. CONFIDENTIALITY

Seller authorizes PG&E to release to the California Energy Commission ("CEC") and/or the CPUC information regarding the Facility, including the Seller's name and location, and the size, location and operational characteristics of the Facility, the Term, the ERR type, the Initial Energy Delivery Date and the net power rating of the Facility, as requested from time to time pursuant to the CEC's or CPUC's rules and regulations.

12. ASSIGNMENT

Neither Party shall assign this Agreement or its rights hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder), transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof to its financing providers and the financing provider(s) shall assume the payment and performance obligations provided under this Agreement with respect to the transferring Party provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request.

13. APPLICABLE LAW

THIS AGREEMENT AND THE RIGHTS AND DUTIES OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF CALIFORNIA, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW. TO THE EXTENT ENFORCEABLE AT SUCH TIME, EACH PARTY WAIVES ITS RESPECTIVE RIGHT TO ANY JURY TRIAL WITH RESPECT TO ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS AGREEMENT.

14. SEVERABILITY

If any provision in this Agreement is determined to be invalid, void or unenforceable by the CPUC or any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Agreement and the Parties shall use their best efforts to modify this Agreement to give effect to the original intention of the Parties.

15. COUNTERPARTS

This Agreement may be executed in one or more counterparts each of which shall be deemed an original and all of which shall be deemed one and the same Agreement. Delivery of an executed counterpart of this Agreement by facsimile or PDF transmission will be deemed as effective as delivery of an originally executed counterpart. Each Party delivering an executed counterpart of this Agreement by facsimile or PDF transmission will also deliver an originally executed counterpart, but the failure of any Party to deliver an originally executed counterpart of this Agreement will not affect the validity or effectiveness of this Agreement.

16. GENERAL

The CPUC has reviewed and approved this Agreement. No amendment to or modification of this Agreement shall be enforceable unless reduced to writing and executed by both parties. This Agreement shall not impart any rights enforceable by any third party other than a permitted successor or assignee bound to this Agreement. Waiver by a Party of any default by the other Party shall not be construed as a waiver of any other default. The term "including" when used in this Agreement shall be by way of example only and shall not be considered in any way to be in limitation. The headings used herein are for convenience and reference purposes only.

IN WITNESS WHEREOF, each Party has caused this Agreement to be duly executed by its authorized representative as of the date of last signature provided below.

PACIFIC GAS AND ELECTRIC COMPANY

By: ______________________________ Date: __________________________

Name: __________________________

Title: ___________________________

SELLER

By: ______________________________ Date: __________________________

Name: __________________________

Title: ___________________________

Appendix A
DEFINITIONS

"Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday during the hours of 8:00 a.m. and 5:00 p.m. local time for the relevant Party's principal place of business where the relevant Party in each instance shall be the Party from whom the notice, payment or delivery is being sent.

"CAISO" means the California Independent System Operator Corporation or any successor entity performing similar functions.

"CAISO Tariff" means the CAISO FERC Electric Tariff, Third Replacement Volume No. 1, as amended from time to time.

"California Renewables Portfolio Standard" means the renewable energy program and policies established by Senate Bill 1038 and 1078, codified in California Public Utilities Code Sections 399.11 through 399.20 and California Public Resources Code Sections 25740 through 25751, as such provisions may be amended or supplemented from time to time.

"CEC" means the California Energy Commission or its successor agency.

"Commercial Operation Date" means the date on which the Facility is operating and is in compliance with applicable interconnection and system protection requirements, and able to produce and deliver energy to PG&E pursuant to the terms of this Agreement.

"Contract Year" means a period of twelve (12) consecutive months with the first Contract Year commencing on the first day of the month immediately following the Initial Energy Delivery Date and each subsequent Contract Year commencing on the anniversary of the Initial Energy Delivery Date.

"CPUC" means the California Public Utilities Commission, or successor entity.

"Delivery Point" means the point of interconnection to the PG&E distribution system.

"Dispatch Down Period" means: (a) curtailments ordered by the CAISO or PG&E as a result of a System Emergency, as defined in the CAISO Tariff; or (b) scheduled or unscheduled maintenance on PG&E's transmission, distribution or interconnection facilities that prevents Buyer from receiving Delivered Energy at the Delivery Point. Notwithstanding the foregoing sentence, Buyer shall have the option in its sole discretion to curtail Seller's energy deliveries up to 50 (fifty) hours each calendar year.

"Eligible Renewable Energy Resource" or "ERR" has the meaning set forth in Public Utilities Code Sections 399.12 and California Public Resources Code Section 25741, as either code provision may be amended or supplemented from time to time.

"Execution Date" means the latest signature date found at the end of the Agreement.

"FERC" means the Federal Energy Regulatory Commission or any successor

government agency.

"Forced Outage" means any unplanned reduction or suspension of the electrical output from the Facility resulting in the unavailability of the Facility, in whole or in part, in response to a mechanical, electrical, or hydraulic control system trip or operator-initiated trip in response to an alarm or equipment malfunction and any other unavailability of the Facility for operation, in whole or in part, for maintenance or repair that is not a scheduled maintenance outage and not the result of Force Majeure.

"Force Majeure" means any event or circumstance which wholly or partly prevents or delays the performance of any material obligation arising under this Agreement, but only if and to the extent (i) such event is not within the reasonable control, directly or indirectly, of the Party seeking to have its performance obligation(s) excused thereby, (ii) the Party seeking to have its performance obligation(s) excused thereby has taken all reasonable precautions and measures to prevent or avoid such event or mitigate the effect of such event on such Party's ability to perform its obligations under this Agreement and which by the exercise of due diligence such Party could not reasonably have been expected to avoid and which by the exercise of due diligence it has been unable to overcome, and (iii) such event is not the direct or indirect result of the negligence or the failure of, or caused by, the Party seeking to have its performance obligations excused thereby. Force Majeure shall not be based on: (i) PG&E's inability economically to use or resell the energy or capacity purchased hereunder; (ii) Seller's ability to sell the energy, capacity or other benefits produced by or associated with the Facility at a price greater than the price set forth in this Agreement, (iii) Seller's inability to obtain approvals of any type for the construction, operation, or maintenance of the Facility; (iv) Seller's inability to obtain sufficient fuel to operate the Facility, except if Seller's inability to obtain sufficient fuel is caused by an event of Force Majeure of the specific type described in any of subsections (i) through (iv) of this definition of Force Majeure; (v) a Forced Outage except where such Forced Outage is caused by an event of Force Majeure of the specific type described in any of subsections (i) through (iv) of this definition of Force Majeure; (vi) a strike or labor dispute limited only to Seller, Seller's affiliates, the Engineering, Procurement, and Construction Contractor or subcontractors thereof; or (vii) any equipment failure not caused by an event of Force Majeure of the specific type described in any of subsections (i) through (iv) of this definition of Force Majeure.

"Green Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Facility, and its displacement of conventional energy generation. Green Attributes include but are not limited to Renewable Energy Credits, as well as: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4) nitrous oxide, hydrofluoro carbons, perfluoro carbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere; (3) the reporting rights to these avoided emissions such as Green Tag Reporting Rights. Green Tag Reporting Rights are the right of a Green Tag Purchaser to report the ownership of accumulated Green Tags in

compliance with federal or state law, if applicable, and to a federal or state agency or any other party at the Green Tag Purchaser's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on MWh basis and one Green Tag represents the Green Attributes associated with one (1) MWh of energy. Green Attributes do not include: (i) any energy, capacity, reliability or other power attributes from the Facility; (ii) production tax credits associated with the construction or operation of the energy projects and other financial incentives in the form of credits, reductions, or allowances associated with the project that are applicable to a state or federal income taxation obligation; (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular pre-existing pollutants or the promotion of local environmental benefits; or (iv) emission reduction credits encumbered or used by the Facility for compliance with local, state, or federal operating and/or air quality permits. If Seller's Facility is a biomass or landfill gas facility and Seller receives any tradable Green Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide Buyer with sufficient Green Attributes to ensure that there are zero net emissions associated with the production of electricity from such facility.

"Law" means any statute, law, treaty, rule, regulation, ordinance, code, permit, enactment, injunction, order, writ, decision, authorization, judgment, decree or other legal or regulatory determination or restriction by a court or Governmental Authority of competent jurisdiction, including any of the foregoing that are enacted, amended, or issued after the Execution Date, and which becomes effective during the Delivery Term; or any binding interpretation of the foregoing.

"Market Price Referent" means the market price referent applicable to this Agreement, as determined by the CPUC in accordance with Public Utilities Code Section 399.15(c), as may be amended or modified from time to time.

"Renewable Energy Credit" has the meaning set forth in Public Utilities Code Section 399.12(g), as may be amended from time to time or as further defined or supplemented by Law.

"Resource Adequacy Benefits" means the rights and privileges attached to the Facility that satisfy any entity's resource adequacy obligations, as those obligations are set forth in any Resource Adequacy Rulings and shall include any local, zonal or otherwise locational attributes associated with the Facility.

"Resource Adequacy Rulings" means CPUC Decisions 04-01-050, 04-10-035, 05-10-042, 06-06-064, 06-07-031 and any subsequent CPUC ruling or decision, or any other resource adequacy laws, rules or regulations enacted, adopted or promulgated by any applicable governmental authority, as such decisions, rulings, laws, rules or regulations may be amended or modified from time-to-time during the Delivery Term.

"Station use" means energy consumed within the Facility's electric energy

distribution system as losses, as well as energy used to operate the Facility's auxiliary equipment. The auxiliary equipment may include, but is not limited to, forced and induced draft fans, cooling towers, boiler feeds pumps, lubricating oil systems, plant lighting, fuel handling systems, control systems, and sump pumps.

"WREGIS" means the Western Renewable Energy Generating Information System or any successor renewable energy tracking program.

Appendix B

INITIAL ENERGY DELIVERY DATE CONFIRMATION LETTER

In accordance with the terms of that certain Section 399.20 Power Purchase Agreement dated _______ ("Agreement") by and between Pacific Gas and Electric Company ("PG&E") and ________________ ("Seller"), this letter serves to document the parties further agreement that (i) the conditions precedent to the occurrence of the Initial Energy Delivery Date have been satisfied, and (ii) Seller has scheduled and PG&E has received the energy, as specified in the Agreement, as of this _____ day of ______, ______. This letter shall confirm the Initial Energy Delivery Date, as defined in the Agreement, as the date referenced in the preceding sentence.

IN WITNESS WHEREOF, each Party has caused this Agreement to be duly executed by its authorized representative as of the date of last signature provided below:

By:	By: Pacific Gas and Electric Company
Name: ___________________________	Name: ___________________________
Title: ___________________________	Title: ___________________________
Date: ___________________________	Date: ___________________________

Appendix C

Time of Delivery (TOD) Periods & Factors

Monthly Period	Super-Peak[1]	Shoulder[2]	Night[3]
Jun – Sep	2.01	1.14	0.72
Oct.- Dec., Jan. & Feb.	1.09	.96	0.78
Mar. – May	1.13	0.86	0.63

Definitions:

1. Super-Peak (5x8) = HE (Hours Ending) 13 – 20 (Pacific Prevailing Time (PPT)), Monday - Friday (*except* NERC holidays) in the applicable Monthly Period.
2. Shoulder = HE 7 - 12, 21 and 22 PPT, Monday - Friday (*except* NERC holidays); and HE 7 - 22 PPT Saturday, Sunday and *all* NERC holidays in the applicable Monthly Period.
3. Night (7x8) = HE 1 - 6, 23 and 24 PPT all days *(including* NERC holidays) in the applicable Monthly Period.

"NERC Holidays" mean the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Three of these days, Memorial Day, Labor Day, and Thanksgiving Day occur on the same day each year. Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the 4th Thursday in November. New Year's Day, Independence Day, and Christmas Day, by definition, are predetermined dates each year. However, in the event they occur on a Sunday, the "NERC Holiday" is celebrated on the Monday immediately following that Sunday. However, if any of these days occur on a Saturday, the "NERC Holiday" remains on that Saturday.

Appendix D

COUNTERPARTY NOTIFICATION AND FORECASTING REQUIREMENTS

A. NOTIFICATION REQUIREMENTS FOR START-UP AND SHUTDOWN

Prior to paralleling to or after disconnecting from the electric system, ALWAYS notify your designated Distribution Operator as follows:

1. Call your Distribution Operator for permission to parallel before any start-up.
2. Call your Distribution Operator again after start-up with parallel time.
3. Call your Distribution Operator after any separation and report separation time as well as date and time estimate for return to service.

B. FORECASTING REQUIREMENTS

1. Seller shall abide with all established requirements and procedures described below:

(a) Generating Facilities 1000 kW and greater must comply with the CAISO Tariff and Protocols while generating facilities under 1000 kW must comply with all applicable interconnection, communication and metering rules; and

(b) Generating Facilities 100 kW and greater must provide a weekly forecast of their expected generation output.

2. Weekly Energy Forecasting Procedures.

Seller must meet all of the following requirements specified below:

Beginning the Wednesday prior to the planned Initial Operation of the Generating Facility, Seller will electronically provide PG&E with an Energy Forecast for the next calendar week, by no later than 5 PM Wednesday of the week preceding the week covered by the Energy Forecast.

The Weekly Energy Forecast submitted to PG&E shall:
a) Not include any anticipated or expected electric energy losses;
b) Be submitted using PG&E's website at https://www.pge.com/qic with Login and password information to be provided, or as otherwise instructed by PG&E;
c) Include Seller's contact information;
d) Limit Day Ahead forecast changes to no less than 100 kW.

2. <u>Outage and Scheduled Maintenance Reporting Procedures.</u>

Send notices of extended outages and proposed scheduled maintenances to PG&E's Internet site (QFSchedules@pge.com). Access and your password to this web site will be provided upon execution of the power purchase agreement.

Electric Sample Form No. 79-1103
Small Renewable Generator PPA

Please Refer to Attached
Sample Form

SMALL RENEWABLE GENERATOR
POWER PURCHASE AGREEMENT
BETWEEN
____________________________________ AND
PACIFIC GAS AND ELECTRIC COMPANY

PACIFIC GAS AND ELECTRIC COMPANY, a California Corporation ("PG&E" or "Buyer"), and _______________________ ("Seller") hereby enter into this Power Purchase Agreement ("Agreement"). Seller and PG&E are sometimes referred to in this Agreement jointly as "Parties" or individually as "Party." In consideration of the mutual promises and obligations stated in this Agreement and its appendices, the Parties agree as follows:

1. DOCUMENTS INCLUDED; DEFINED TERMS

This Agreement includes the following appendices, which are specifically incorporated herein and made a part of this Agreement.

Appendix A- Definitions

Appendix B- Initial Energy Delivery Date Confirmation Letter

Appendix C- Time of Delivery ("TOD") Periods and Factors

Appendix D- Counterparty Notification Requirements for Outage and Generation Schedule Changes

2. SELLER'S GENERATING FACILITY, PURCHASE PRICES AND PAYMENT

2.1 Facility. This Agreement governs PG&E's purchase of energy and capacity from the electrical generating facility (hereinafter referred to as the "Facility" or "Unit") as described in this Section.

2.1.1 The Facility is located at ________________ in _________ County, California.

2.1.2 The Facility is described as ___________________________.

2.1.3 The Facility's primary fuel is _______ [i.e. biogas, hydro, etc.].

2.1.4 The Facility has a nameplate rating of ___ kilowatts ("kW"), at unity power factor at 60 degrees Fahrenheit at sea level and has a primary voltage level of ____ kilovolts ("kV"). Seller shall not modify the Facility to increase the nameplate rating without the prior written consent of PG&E.

2.1.5 The Facility is connected to the PG&E electric system at _____ kV.

2.1.6 If not already capable of delivering energy on the Execution Date, the Facility's scheduled Commercial Operation Date is ________________.

2.1.7 A description of the Facility, including a summary of its significant components, a drawing showing the general arrangements of the Facility, and a single line diagram illustrating the interconnection of the Facility and loads with PG&E's electric distribution system, is attached and incorporated herein as Appendix E.

2.1.8 The name and address PG&E uses to locate the electric service account(s) and premises used to interconnect the Facility with PG&E's distribution systems is:

____

____

____

____

2.2 Transaction. During the Delivery Term of this Agreement, as provided in Section 2.3, Seller shall sell and deliver, or cause to be delivered, and PG&E shall purchase and receive, or cause to be received, energy produced by and capacity provided from the Facility, up to 1500 kW, at the Delivery Point, as defined pursuant to Section 5.1, pursuant to Seller's election of a (check one) ☐ full buy/sell or ☐ excess sale arrangement as described in paragraphs 2.2.1 and 2.2.2 below. PG&E shall pay Seller the Contract Price, set forth in Section 2.4, in accordance with the terms hereof. In no event shall Seller have the right to procure the energy or capacity from sources other than the Facility for sale or delivery to PG&E under this Agreement or substitute such energy or capacity. PG&E shall have no obligation to receive or purchase energy or capacity from Seller prior to the Initial Energy Delivery Date, as defined in Section 2.3, or after the end of the Delivery Term, as defined in Section 2.3. The Parties agree that the execution and performance of the Parties under this Agreement shall satisfy PG&E's obligations, if any, under the Public Utility Regulatory Policies Act and its implementing regulations, i.e., 18 C.F.R. §§ 292.303.

2.2.1 Full Buy/Sell. Seller agrees to sell to PG&E the Facility's gross output in kilowatt-hours, net of Station Use and transformation and transmission losses to the Delivery Point into the PG&E system, together with all Green Attributes and Resource Adequacy Benefits. Seller shall purchase all energy required to serve the Facility's on-site load, net of station use, from PG&E pursuant to PG&E's applicable retail rate schedule.

2.2.2 Excess Sale. Seller agrees to sell to PG&E the Facility's gross output in kilowatt-hours, net of Station Use and any on-site use by Seller and transformation and transmission losses to the Delivery Point into the PG&E system. Seller agrees to convey to PG&E all Green Attributes and Resource Adequacy Benefits associated with the energy sold to PG&E.

2.3 Delivery Term. The Seller shall deliver the energy and capacity from the Facility to PG&E for a period of (check one) ☐ ten (10), ☐ fifteen (15), or ☐ twenty (20) Contract Years ("Delivery Term"), which shall commence on the first date on which energy is delivered from the Facility to PG&E ("Initial Energy Delivery Date") under this Agreement and continue until the end of the last Contract Year unless terminated by the terms of this Agreement. The Initial Energy Delivery Date shall occur only when all of the following conditions have been satisfied:

(i) the Commercial Operation Date has occurred, if the Facility was not in operation prior to the Execution Date of this Agreement;

(ii) the Facility's status as an Eligible Renewable Energy Resource, is demonstrated by Seller's receipt of certification from the CEC and is registered in WREGIS; and

(iii) as evidence of the Initial Energy Delivery Date, the Parties shall execute and exchange the "Initial Energy Delivery Date Confirmation Letter" attached hereto as Appendix B on the Initial Energy Delivery Date.

2.4 Contract Price. Once both Parties have executed this Agreement PG&E shall pay Seller for each megawatt-hour ("MWh") of energy and associated capacity delivered to PG&E during each Contract Year for the Delivery Term at the applicable Market Price Referent specified below for the Facility's actual Commercial Operation Date. Payment shall be adjusted by the appropriate Time of Delivery ("TOD") factor listed in Appendix C.

Adopted 2008 Market Price Referents[1] (Nominal - dollars/kWh)			
Resource Type	**10-Year**	**15-Year**	**20-Year**
2009 Baseload MPR	0.10043	0.10537	0.11126
2010 Baseload MPR	0.10175	0.10748	0.11390
2011 Baseload MPR	0.10400	0.11046	0.11730
2012 Baseload MPR	0.10698	0.11405	0.12126
2013 Baseload MPR	0.10998	0.11776	0.12527
2014 Baseload MPR	0.11278	0.12122	0.12897
2015 Baseload MPR	0.11605	0.12503	0.13290
2016 Baseload MPR	0.11971	0.12915	0.13706
2017 Baseload MPR	0.12367	0.13352	0.14144
2018 Baseload MPR	0.12802	0.13814	0.14603
2019 Baseload MPR	0.13271	0.14298	0.15080
2020 Baseload MPR	0.13776	0.14797	0.15578

[1] Note: Using 2009 as the base year, Staff calculates MPRs for 2009-2020 that reflect different project online dates. Link to 2008 MPR Model: http://www.ethree.com/MPR.html

2.5 Billing. PG&E shall pay Seller by check or Automated Clearing House transfer within approximately 30 days of the meter reading date if the value of the purchased energy in a month is at least fifty dollars ($50); if less, PG&E may pay Seller quarterly. PG&E shall have the right, but not the obligation, to read the Facility's meter on a daily basis.

2.6 Title and Risk of Loss. Title to and risk of loss related to the energy produced from and capacity provided by the Facility shall transfer from Seller to PG&E at the Delivery Point. Seller warrants that it will deliver to PG&E all energy and capacity from the Facility free and clear of all liens, security interests, claims and encumbrances or any interest therein or thereto by any person arising prior to the Delivery Point.

2.7 No Additional Incentives. Seller agrees that during the Term of this Agreement, Seller shall not seek additional compensation or other benefits pursuant to the Self-Generation Incentive Program, as defined in CPUC Decision ("D.") 01-03-073, the California Solar Initiative, as defined in CPUC D.06-01-024, PG&E's net energy metering tariff, or other similar California ratepayer subsidized program relating to energy production with respect to the Facility.

2.8 Private Energy Producer. Seller agrees to provide to Buyer copies of each of the documents identified in PUC Section 2821(d)(1), if applicable, as may be amended from time to time, as evidence of Seller's compliance with such PUC section. Such documentation shall be provided to Buyer within thirty (30) days of Seller's receipt of written request therefor.

3. GREEN ATTRIBUTES; RESOURCE ADEQUACY BENEFITS

3.1 Conveyance of Green Attributes. Seller provides and conveys all Green Attributes from the Facility to Buyer as part of the Product (energy and capacity) delivered to Buyer for the duration of the Delivery Term. Seller represents and warrants that Seller holds the rights to all Green Attributes from the Facility, and Seller agrees to convey and hereby conveys all such Green Attributes to Buyer as included in the delivery of the Product from the Facility. Further, "Green Attributes" also means any and all credits that satisfy the requirement to procure electricity from ERRs, pursuant to the California Renewables Portfolio Standard, that are directly attributable to electric production from the Facility. Seller represents that the energy, capacity, ancillary services and Green Attributes from the Facility have not been, nor will be, sold or used to satisfy any obligation other than PG&E's California Renewables Portfolio Standard obligation.

3.2 WREGIS. Prior to the Initial Energy Delivery Date, Seller shall register the Facility in WREGIS and take all other actions necessary to ensure that the energy produced from the Facility is tracked for purposes of satisfying the California Renewables Portfolio Standard requirements, as may be amended or supplemented by the CPUC or CEC from time to time. Seller warrants that all it shall take all necessary steps to ensure the Renewable Energy Credits transferred to Buyer under this Agreement are tracked in WREGIS and transferred in a timely manner to Buyer through WREGIS for purposes of satisfying Buyer's California Renewables Portfolio Standard Requirements, as may be amended or supplemented by the CPUC or CEC from time to time.

3.3 Resource Adequacy Benefits. In accordance with PUC Section 399.20(g), Seller conveys to PG&E all Resource Adequacy Benefits attributable to the physical generating capacity of Seller's Facility to enable PG&E to count such capacity towards PG&E's resource adequacy requirement for purposes of PUC Section 380. Seller shall take all reasonable actions and execute documents and instructions necessary to enable Buyer to secure Resource Adequacy Benefits; Seller shall comply with all applicable reporting requirements.

4. REPRESENTATION AND WARRANTIES; COVENANTS

4.1 Representations and Warranties. On the Execution Date, each Party represents and warrants to the other Party that:

4.1.1 it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

4.1.2 the execution, delivery and performance of this Agreement is within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

4.1.3 this Agreement and each other document executed and delivered in accordance with this Agreement constitutes its legally valid and binding obligation enforceable against it in accordance with its terms;

4.1.4 it is not bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming bankrupt;

4.1.5 there is not pending or, to its knowledge, threatened against it or any of its affiliates any legal proceedings that could materially adversely affect its ability to perform its obligations under this Agreement; and

4.1.6 it is acting for its own account, has made its own independent decision to enter into this Agreement and as to whether this Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing the merits of, and understands and accepts, the terms, conditions and risks of this Agreement.

4.2 General Covenants. Each Party covenants that throughout the Term of this Agreement:

4.2.1 it shall continue to be duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

4.2.2 it shall maintain (or obtain from time to time as required, including through renewal, as applicable) all regulatory authorizations necessary for it to legally perform its obligations under this Agreement; and

4.2.3 it shall perform its obligations under this Agreement in a manner that does not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it.

4.3 Seller Representation and Warranty and Covenant.

4.3.1 Representation and Warranty. In addition to the representations and warranties specified in Section 4.1, Seller makes the following additional representations and warranties as of the Execution Date:

(a) Seller has not received an incentive under the Self-Generation Incentive Program, as defined in CPUC D.01-03-073, or the California Solar Initiative, as defined in CPUC D.06-01-024.

(b) Seller's execution of this Agreement will not violate PUC Section 2821(d)(1) if applicable.

4.3.2 Covenant. Seller hereby covenants that throughout the Term of the Agreement, the Facility is, or will qualify prior to the Initial Energy Delivery Date, as an ERR, specifically, Seller and, if applicable, its successors, represents and warrants throughout the term of the Delivery Term of each Transaction entered into under this Agreement that: (a) the Unit(s) qualifies and is certified by the CEC as an Eligible Renewable Energy Resource; and (b) the Unit(s) output delivered to Buyer qualifies under the requirements of the California Renewables Portfolio Standard. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

5. GENERAL CONDITIONS

5.1 Facility Care, Interconnection and Transmission Service. If PG&E does not deem Seller's existing interconnection service, equipment and agreement satisfactory for the delivery of energy under this Agreement, Seller shall execute a Small Generator Interconnection Agreement with PG&E's Generation Interconnection Services Department and pay and be responsible for designing, installing, operating, and maintaining the Facility in accordance with all applicable laws and regulations and shall comply with all applicable PG&E, CAISO, CPUC and FERC tariff provisions, including applicable interconnection and metering requirements. Seller shall also comply with any modifications, amendments or additions to the applicable tariff and protocols. During the Delivery Term, Seller shall arrange and pay independently for any and all necessary costs under any interconnection agreement with PG&E. To make deliveries to PG&E, Seller must maintain an interconnection agreement with PG&E in full force and effect.

5.2 Metering Requirements. Seller shall comply with all applicable rules in installing a meter appropriate for deliveries pursuant to the Full Buy/Sell or Excess Sale arrangement selected in paragraph 2.2, above, which can be electronically read daily by: (a) a telephone and modem; (b) an analog or digital phone connection; or (c) an internet portal address for PG&E's Energy Data Services ("EDS"). Seller shall be responsible for procuring and maintaining the communication link to electronically retrieve this metering data.

5.3 Standard of Care. Seller shall: (a) maintain and operate the Facility and Interconnection Facilities, except facilities installed by PG&E, in conformance with all applicable laws and regulations and in accordance with Good Utility Practices, as defined by PG&E's Wholesale Distribution Tariff and the CAISO Tariff, as they may be amended, supplemented or replaced (in whole or in part) from time to time; (b) obtain any governmental authorizations and permits required for the construction and operation thereof; and (c) generate, schedule and perform transmission services in compliance with all applicable operating policies, criteria, rules, guidelines and tariffs and Good Utility Practices, as provided in clause (a) above. Seller shall reimburse PG&E for any and all losses, damages, claims, penalties, or liability PG&E incurs as a result of Seller's failure to obtain or maintain any governmental authorizations and permits required for construction and operation of the Facility throughout the Term of this Agreement.

5.4 Access Rights. PG&E, its authorized agents, employees and inspectors shall have the right to inspect the Facility on reasonable advance notice during normal business hours and for any purposes reasonably connected with this Agreement or the exercise of any and all rights secured to PG&E by law, or its tariff schedules, PG&E Interconnection Handbook and rules on file with the CPUC. PG&E shall make reasonable efforts to coordinate its emergency activities with the Safety and Security Departments, if any, of the Facility operator. Seller shall keep PG&E advised of current procedures for communicating with the Facility operator's Safety and Security Departments.

5.5 Protection of Property. Each Party shall be responsible for protecting its own facilities from possible damage resulting from electrical disturbances or faults caused by the operation, faulty operation, or non-operation of the other Party's facilities and such other Party shall not be liable for any such damages so caused.

5.6 PG&E Performance Excuse; Seller Curtailment.

5.6.1 PG&E Performance Excuse. PG&E shall not be obligated to accept or pay for energy produced by or capacity provided from the Facility during a Dispatch Down Period, or Force Majeure, as defined in Appendix A.

5.6.2 Seller Curtailment. PG&E may require Seller to interrupt or reduce deliveries of energy: (a) when necessary to construct, install, maintain, repair, replace, remove, or investigate any of its equipment or part of PG&E's transmission system or distribution system or facilities; or (b) if PG&E or the CAISO determines that curtailment, interruption, or reduction is necessary because of a System Emergency, as defined in the CAISO Tariff, Forced Outage, Force Majeure as defined in Appendix A, or compliance with Good Utility Practice, as such term is defined in the CAISO Tariff.

5.7 Notices of Outages. Whenever possible, PG&E shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries may be required.

5.8 Greenhouse Gas Emissions: During the Term, Seller acknowledges that a Governmental Authority may require Buyer to take certain actions with respect to greenhouse gas emissions *attributable to the generation of Energy*, including, but not limited to, reporting, registering, tracking, allocating for or accounting for such emissions. Promptly following Buyer's written request, Seller agrees to take all commercially reasonable actions and execute or provide any and all documents, information or instruments *with respect to generation by the Project* reasonably necessary to permit Buyer to comply with such requirements, if any.

6. INDEMNITY

Each Party as indemnitor shall save harmless and indemnify the other Party and the directors, officers, and employees of such other Party against and from any and all loss and liability for injuries to persons including employees of either Party, and damages, including property of either Party, resulting from or arising out of: (a) the engineering, design, construction, maintenance, or operation of; or (b) the installation of replacements, additions, or betterments to the indemnitor's facilities. This indemnity and save harmless provision shall apply notwithstanding the active or passive negligence of the indemnitee. Neither Party shall be indemnified for liability or loss, resulting from its sole negligence or willful misconduct. The indemnitor shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity and shall pay all costs, including reasonable attorney fees that may be incurred by the other Party in enforcing this indemnity.

7. LIMITATION OF DAMAGES

EXCEPT AS OTHERWISE PROVIDED IN THIS AGREEMENT THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY

AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED UNLESS EXPRESSLY HEREIN PROVIDED. NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. UNLESS EXPRESSLY HEREIN PROVIDED, AND SUBJECT TO THE PROVISIONS OF SECTION 6 (INDEMNITY), IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE.

8. NOTICES

Notices shall, unless otherwise specified herein, be in writing and may be delivered by hand delivery, United States mail, overnight courier service, facsimile or electronic messaging (e-mail). Whenever this Agreement requires or permits delivery of a "notice" (or requires a Party to "notify"), the Party with such right or obligation shall provide a written communication in the manner specified below. A notice sent by facsimile transmission or e-mail will be recognized and shall be deemed received on the Business Day on which such notice was transmitted if received before 5 p.m. Pacific prevailing time (and if received after 5 p.m., on the next Business Day) and a notice by overnight mail or courier shall be deemed to have been received two (2) Business Days after it was sent or such earlier time as is confirmed by the receiving Party unless it confirms a prior oral communication, in which case any such notice shall be deemed received on the day sent. A Party may change its addresses by providing notice of same in accordance with this provision. All written notices shall be directed as follows:

TO PG&E:

Pacific Gas and Electric Company
Attention: Manager, Contract Management
245 Market Street, Mail Code N12E
San Francisco, CA 94177-0001

TO SELLER:

____
____
____
____

9. INSURANCE

9.1 General Liability Coverage.

9.1.1 Seller shall maintain during the performance hereof, General Liability Insurance[2] of not less than $1,000,000 if the Facility's nameplate is over 100 kW, $500,000 if the nameplate rating of the Facility is over 20 kW to 100kW or $100,000 if the nameplate rate of the Facility is 20 kW or below of combined single limit or equivalent for bodily injury, personal injury, and property damage as the result of any one occurrence.

9.1.2 General Liability Insurance shall include coverage for Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations.

9.1.3 Such insurance shall provide for thirty (30) days written notice to PG&E prior to cancellation, termination, alteration, or material change of such insurance.

9.2 Additional Insurance Provisions.

9.2.1 Evidence of coverage described above in Paragraph 9.1 shall state that coverage provided in primary and is not excess to or contributing with any insurance or self-insurance maintained by PG&E.

9.2.2 PG&E shall have the right to inspect or obtain a copy of the original policy(ies) of insurance.

9.2.3 Seller shall furnish the required certificates and endorsements to PG&E prior to commencing operation.

9.2.4 All insurance certificates, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

Pacific Gas and Electric Company

Attention: Manager, Insurance Department

77 Beale Street, Room E280

San Francisco, CA 94105

10. TERM, DEFAULT, TERMINATON EVENT AND TERMINATION

10.1 Term. The term of this Agreement shall commence upon the later of: (i) execution by the duly authorized representatives of each of PG&E and Seller; or (ii) when PG&E notifies Seller that PG&E can accommodate Seller's Facility in PG&E's

[2] Governmental agencies which have an established record of self-insurance may provide the required coverage through self-insurance.

proportionate share of the statewide cumulative total of 250 MW as specified in PUC Section 399.20(e), and shall remain in effect until the conclusion of the Delivery Term or unless terminated sooner pursuant to Section 10.3 of this Agreement (the "Term"). All indemnity rights shall survive the termination of this Agreement for twelve (12) months.

10.2 Termination Event. Buyer shall be entitled to terminate the Agreement upon the occurrence of any of the following, each of which is a "Termination Event":

(a) The Facility has not achieved Commercial Operation within eighteen (18) months of the Execution Date of this Agreement;

(b) Seller has not sold or delivered energy from the Facility to PG&E for a period of twelve (12) consecutive months;

(c) Seller breaches its covenant to maintain its status as an ERR as set forth in Section 4.3.2. of the Agreement.

10.3 Termination.

10.3.1 Declaration of a Termination Event. If a Termination Event has occurred and is continuing, Buyer shall have the right to: (a) send notice, designating a day, no earlier than five days after such notice is deemed to be received (as provided in Section 8) and no later than 20 days after such notice is deemed to be received (as provided in Section 8), as an early termination date of this Agreement ("Early Termination Date") unless Seller has timely communicated with Buyer and the Parties have agreed to resolve the circumstances giving rise to the termination Event; (b) accelerate all amounts owing between the Parties; and (c) terminate this Agreement and end the Delivery Term effective as of the Early Termination Date.

10.3.2 Release of Liability for Termination Event. Upon termination of this Agreement pursuant to Section 10.3.1, neither Party shall be under any further obligation or subject to liability hereunder, except with respect to the indemnity provision in Section 6 hereof, which shall remain in effect for a period of 12 months following the Early Termination Date.

11. SCHEDULING

11.1 Scheduling Obligations. PG&E shall be Seller's designated Scheduling Coordinator (as defined by CAISO tariff). PG&E will schedule Seller' project using Prudent Utility Practices and Seller shall employ Prudent Utility Practices and exercise reasonable efforts to operate and maintain its project. All generation interconnection and scheduling services shall be performed in accordance with all applicable operating policies, criteria, guidelines and tariffs of the CAISO or its successor, and any other generally accepted operational requirements. Seller, at its own expense, shall be responsible for complying with all applicable contractual, metering and interconnection requirements. Seller shall promptly notify PG&E of significant (i.e., greater than 100 kW) changes to its energy schedules using

PG&E's web site (see Appendix D). Seller will exercise reasonable efforts to comply with conditions that might arise if the CAISO modifies or amends its tariffs, standards, requirements, and/or protocols in the future.

11.2 CAISO Charges.

11.2.1 CAISO Charge Obligations. PG&E and Seller shall cooperate to minimize CAISO delivery imbalances and any resulting fees, liabilities, assessments or similar charges assessed by the CAISO ("CAISO Charges") to the extent possible, and shall each promptly notify the other as soon as possible of any material loss of system capability, deviation or imbalance that is occurring or has occurred. Seller shall reimburse PG&E for any CAISO Charges PG&E incurs as a result of Seller's loss of system capability, deviation or imbalance. Any such CAISO Charges reimbursable to PG&E shall be limited to the period until the commencement of the next settlement period following Seller's notification for which the delivery schedule can be adjusted. Notwithstanding anything to the contrary herein, in the event Seller makes a change to its schedule on the actual date and time of delivery for any reason (other than an adjustment imposed by CAISO) which results in differences between the project's actual generation and the scheduled generation (whether in part or in whole), Seller shall use reasonable efforts to notify PG&E. PG&E will make commercially reasonable efforts to accommodate Seller's changes and mitigate any imbalance penalties or charges levied for such changes.

11.2.2 CAISO Penalties. Seller shall be responsible for any "non-Performance Penalties" assessed to PG&E by the CAISO ("CAISO Penalties"), under the CAISO Tariff Enforcement Protocol, and not due to any fault of PG&E, which shall include, without limitation, any deviation, imbalance or uninstructed energy charges or penalties payable to the CAISO that are due to the fault of Seller. To the extent that Seller materially deviates from its energy schedules (other than an adjustment imposed by the CAISO, a deviation due to any fault of PG&E, or an excused Seller failure to deliver, whether for reasons of Force Majeure or otherwise), and such departure results in CAISO Penalties being assessed to PG&E, such CAISO Penalties shall be passed on to Seller. Any such CAISO Penalties passed on to Seller shall be limited to the period until the commencement of the next settlement period following Seller's notification (as described above) for which the delivery schedule can be adjusted.

12. CONFIDENTIALITY

Seller authorizes PG&E to release to the California Energy Commission ("CEC") and/or the CPUC information regarding the Facility, including the Seller's name and location, and the size, location and operational characteristics of the Facility, the Term, the ERR type, the Initial Energy Delivery Date and the net power rating of the Facility, as requested from time to time pursuant to the CEC's or CPUC's rules and regulations.

13. ASSIGNMENT

Neither Party shall assign this Agreement or its rights hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder), transfer, sell, pledge, encumber or assign this

Agreement or the accounts, revenues or proceeds hereof to its financing providers and the financing provider(s) shall assume the payment and performance obligations provided under this Agreement with respect to the transferring Party provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request.

14. APPLICABLE LAW

THIS AGREEMENT AND THE RIGHTS AND DUTIES OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF CALIFORNIA, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW. TO THE EXTENT ENFORCEABLE AT SUCH TIME, EACH PARTY WAIVES ITS RESPECTIVE RIGHT TO ANY JURY TRIAL WITH RESPECT TO ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS AGREEMENT.

15. SEVERABILITY

If any provision in this Agreement is determined to be invalid, void or unenforceable by the CPUC or any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Agreement and the Parties shall use their best efforts to modify this Agreement to give effect to the original intention of the Parties.

16. COUNTERPARTS

This Agreement may be executed in one or more counterparts each of which shall be deemed an original and all of which shall be deemed one and the same Agreement. Delivery of an executed counterpart of this Agreement by facsimile or PDF transmission will be deemed as effective as delivery of an originally executed counterpart. Each Party delivering an executed counterpart of this Agreement by facsimile or PDF transmission will also deliver an originally executed counterpart, but the failure of any Party to deliver an originally executed counterpart of this Agreement will not affect the validity or effectiveness of this Agreement.

17. GENERAL

The CPUC has reviewed and approved this Agreement. No amendment to or modification of this Agreement shall be enforceable unless reduced to writing and executed by both parties. This Agreement shall not impart any rights enforceable by any third party other than a permitted successor or assignee bound to this Agreement. Waiver by a Party of any default by the other Party shall not be construed as a waiver of any other default. The term "including" when used in this Agreement shall be by way of example only and shall not be considered in any way to be in limitation. The headings used herein are for convenience and reference purposes only.

IN WITNESS WHEREOF, each Party has caused this Agreement to be duly executed by its authorized representative as of the date of last signature provided below.

PACIFIC GAS AND ELECTRIC COMPANY

By: ______________________________ Date: __________________________

Name: __________________________

Title: ___________________________

SELLER

By: ______________________________ Date: __________________________

Name: __________________________

Title: ___________________________

Appendix A
DEFINITIONS

"Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday during the hours of 8:00 a.m. and 5:00 p.m. local time for the relevant Party's principal place of business where the relevant Party in each instance shall be the Party from whom the notice, payment or delivery is being sent.

"CAISO" means the California Independent System Operator Corporation or any successor entity performing similar functions.

"CAISO Tariff" means the CAISO FERC Electric Tariff, Third Replacement Volume No. 1, as amended from time to time.

"California Renewables Portfolio Standard" means the renewable energy program and policies established by Senate Bill 1038 and 1078, codified in California Public Utilities Code Sections 399.11 through 399.20 and California Public Resources Code Sections 25740 through 25751, as such provisions may be amended or supplemented from time to time.

"CEC" means the California Energy Commission or its successor agency.

"Commercial Operation Date" means the date on which the Facility is operating and is in compliance with applicable interconnection and system protection requirements, and able to produce and deliver energy to PG&E pursuant to the terms of this Agreement.

"Contract Year" means a period of twelve (12) consecutive months with the first Contract Year commencing on the first day of the month immediately following the Initial Energy Delivery Date and each subsequent Contract Year commencing on the anniversary of the Initial Energy Delivery Date.

"CPUC" means the California Public Utilities Commission, or successor entity.

"Delivery Point" means the point of interconnection to the PG&E distribution system.

"Dispatch Down Period" means: (a) curtailments ordered by the CAISO or PG&E as a result of a System Emergency, as defined in the CAISO Tariff; or (b) scheduled or unscheduled maintenance on PG&E's transmission, distribution or interconnection facilities that prevents Buyer from receiving Delivered Energy at the Delivery Point. Notwithstanding the foregoing sentence, Buyer shall have the option in its sole discretion to curtail Seller's energy deliveries up to 50 (fifty) hours each calendar year.

"Eligible Renewable Energy Resource" or "ERR" has the meaning set forth in Public Utilities Code Sections 399.12 and California Public Resources Code Section 25741, as either code provision may be amended or supplemented from time to time.

"Execution Date" means the latest signature date found at the end of the Agreement.

"FERC" means the Federal Energy Regulatory Commission or any successor

government agency.

"Forced Outage" means any unplanned reduction or suspension of the electrical output from the Facility resulting in the unavailability of the Facility, in whole or in part, in response to a mechanical, electrical, or hydraulic control system trip or operator-initiated trip in response to an alarm or equipment malfunction and any other unavailability of the Facility for operation, in whole or in part, for maintenance or repair that is not a scheduled maintenance outage and not the result of Force Majeure.

"Force Majeure" means any event or circumstance which wholly or partly prevents or delays the performance of any material obligation arising under this Agreement, but only if and to the extent (i) such event is not within the reasonable control, directly or indirectly, of the Party seeking to have its performance obligation(s) excused thereby, (ii) the Party seeking to have its performance obligation(s) excused thereby has taken all reasonable precautions and measures to prevent or avoid such event or mitigate the effect of such event on such Party's ability to perform its obligations under this Agreement and which by the exercise of due diligence such Party could not reasonably have been expected to avoid and which by the exercise of due diligence it has been unable to overcome, and (iii) such event is not the direct or indirect result of the negligence or the failure of, or caused by, the Party seeking to have its performance obligations excused thereby. Force Majeure shall not be based on: (i) PG&E's inability economically to use or resell the energy or capacity purchased hereunder; (ii) Seller's ability to sell the energy, capacity or other benefits produced by or associated with the Facility at a price greater than the price set forth in this Agreement, (iii) Seller's inability to obtain approvals of any type for the construction, operation, or maintenance of the Facility; (iv) Seller's inability to obtain sufficient fuel to operate the Facility, except if Seller's inability to obtain sufficient fuel is caused by an event of Force Majeure of the specific type described in any of subsections (i) through (iv) of this definition of Force Majeure; (v) a Forced Outage except where such Forced Outage is caused by an event of Force Majeure of the specific type described in any of subsections (i) through (iv) of this definition of Force Majeure; (vi) a strike or labor dispute limited only to Seller, Seller's affiliates, the Engineering, Procurement, and Construction Contractor or subcontractors thereof; or (vii) any equipment failure not caused by an event of Force Majeure of the specific type described in any of subsections (i) through (iv) of this definition of Force Majeure.

"Green Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Facility, and its displacement of conventional energy generation. Green Attributes include but are not limited to Renewable Energy Credits, as well as: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4) nitrous oxide, hydrofluoro carbons, perfluoro carbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere; (3) the reporting rights to these avoided emissions such as Green Tag Reporting Rights. Green Tag Reporting Rights are the right of a Green Tag Purchaser to report the ownership of accumulated Green Tags in

compliance with federal or state law, if applicable, and to a federal or state agency or any other party at the Green Tag Purchaser's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on MWh basis and one Green Tag represents the Green Attributes associated with one (1) MWh of energy. Green Attributes do not include: (i) any energy, capacity, reliability or other power attributes from the Facility; (ii) production tax credits associated with the construction or operation of the energy projects and other financial incentives in the form of credits, reductions, or allowances associated with the project that are applicable to a state or federal income taxation obligation; (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular pre-existing pollutants or the promotion of local environmental benefits; or (iv) emission reduction credits encumbered or used by the Facility for compliance with local, state, or federal operating and/or air quality permits. If Seller's Facility is a biomass or landfill gas facility and Seller receives any tradable Green Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide Buyer with sufficient Green Attributes to ensure that there are zero net emissions associated with the production of electricity from such facility.

"Law" means any statute, law, treaty, rule, regulation, ordinance, code, permit, enactment, injunction, order, writ, decision, authorization, judgment, decree or other legal or regulatory determination or restriction by a court or Governmental Authority of competent jurisdiction, including any of the foregoing that are enacted, amended, or issued after the Execution Date, and which becomes effective during the Delivery Term; or any binding interpretation of the foregoing.

"Market Price Referent" means the market price referent applicable to this Agreement, as determined by the CPUC in accordance with Public Utilities Code Section 399.15(c), as may be amended or modified from time to time.

"Renewable Energy Credit" has the meaning set forth in Public Utilities Code Section 399.12(g), as may be amended from time to time or as further defined or supplemented by Law.

"Resource Adequacy Benefits" means the rights and privileges attached to the Facility that satisfy any entity's resource adequacy obligations, as those obligations are set forth in any Resource Adequacy Rulings and shall include any local, zonal or otherwise locational attributes associated with the Facility.

"Resource Adequacy Rulings" means CPUC Decisions 04-01-050, 04-10-035, 05-10-042, 06-06-064, 06-07-031 and any subsequent CPUC ruling or decision, or any other resource adequacy laws, rules or regulations enacted, adopted or promulgated by any applicable governmental authority, as such decisions, rulings, laws, rules or regulations may be amended or modified from time-to-time during the Delivery Term.

"Station use" means energy consumed within the Facility's electric energy

distribution system as losses, as well as energy used to operate the Facility's auxiliary equipment. The auxiliary equipment may include, but is not limited to, forced and induced draft fans, cooling towers, boiler feeds pumps, lubricating oil systems, plant lighting, fuel handling systems, control systems, and sump pumps.

"WREGIS" means the Western Renewable Energy Generating Information System or any successor renewable energy tracking program.

Appendix B

INITIAL ENERGY DELIVERY DATE CONFIRMATION LETTER

In accordance with the terms of that certain Small Renewable Generator Power Purchase Agreement dated _______ ("Agreement") by and between Pacific Gas and Electric Company ("PG&E") and ________________ ("Seller"), this letter serves to document the parties further agreement that (i) the conditions precedent to the occurrence of the Initial Energy Delivery Date have been satisfied, and (ii) Seller has scheduled and PG&E has received the energy, as specified in the Agreement, as of this _____ day of ______, ______. This letter shall confirm the Initial Energy Delivery Date, as defined in the Agreement, as the date referenced in the preceding sentence.

IN WITNESS WHEREOF, each Party has caused this Agreement to be duly executed by its authorized representative as of the date of last signature provided below:

By:	By: Pacific Gas and Electric Company
Name: __________________________	Name: __________________________
Title: __________________________	Title: __________________________
Date: __________________________	Date: __________________________

Appendix C

Time of Delivery (TOD) Periods & Factors

Monthly Period	**Super-Peak**[1]	**Shoulder**[2]	**Night**[3]
Jun – Sep	2.01	1.14	0.72
Oct.- Dec., Jan. & Feb.	1.09	.96	0.78
Mar. – May	1.13	0.86	0.63

Definitions:

1. Super-Peak (5x8) = HE (Hours Ending) 13 – 20 (Pacific Prevailing Time (PPT)), Monday - Friday (*except* NERC holidays) in the applicable Monthly Period.
2. Shoulder = HE 7 - 12, 21 and 22 PPT Monday - Friday (*except* NERC holidays); and HE 7 - 22 PPT Saturday, Sunday and *all* NERC holidays in the applicable Monthly Period.
3. Night (7x8) = HE 1 - 6, 23 and 24 PPT all days *(including* NERC holidays) in the applicable Monthly Period.

"NERC Holidays" mean the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Three of these days, Memorial Day, Labor Day, and Thanksgiving Day occur on the same day each year. Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the 4th Thursday in November. New Year's Day, Independence Day, and Christmas Day, by definition, are predetermined dates each year. However, in the event they occur on a Sunday, the "NERC Holiday" is celebrated on the Monday immediately following that Sunday. However, if any of these days occur on a Saturday, the "NERC Holiday" remains on that Saturday.

Appendix D

COUNTERPARTY NOTIFICATION AND FORECASTING REQUIREMENTS

A. NOTIFICATION REQUIREMENTS FOR START-UP AND SHUTDOWN

Prior to paralleling to or after disconnecting from the electric system, ALWAYS notify your designated Distribution Operator as follows:

1. Call your Distribution Operator for permission to parallel before any start-up.
2. Call your Distribution Operator again after start-up with parallel time.
3. Call your Distribution Operator after any separation and report separation time as well as date and time estimate for return to service.

B. FORECASTING REQUIREMENTS

1. Seller shall abide with all established requirements and procedures described below:

(a) Generating Facilities 1000 kW and greater must comply with the CAISO Tariff and Protocols while generating facilities under 1000 kW must comply with all applicable interconnection, communication and metering rules; and

(b) Generating Facilities 100 kW and greater must provide a weekly forecast of their expected generation output.

2. Weekly Energy Forecasting Procedures.

Seller must meet all of the following requirements specified below:

Beginning the Wednesday prior to the planned Initial Operation of the Generating Facility, Seller will electronically provide PG&E with an Energy Forecast for the next calendar week, by no later than 5 PM Wednesday of the week preceding the week covered by the Energy Forecast.

The Weekly Energy Forecast submitted to PG&E shall:
a) Not include any anticipated or expected electric energy losses;
b) Be using PG&E's website at https://www.pge.com/qic with Login and password information to be provided, or as otherwise instructed by PG&E;
c) Include Seller's contact information;
d) Limit Day Ahead forecast changes to no less than 100 kW.

2. <u>Outage and Scheduled Maintenance Reporting Procedures.</u>

Send notices of extended outages and proposed scheduled maintenances to PG&E's Internet site (QFSchedules@pge.com). Access and your password to this web site will be provided upon execution of the power purchase agreement.

ELECTRIC TABLE OF CONTENTS

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SCHEDULE TITLE OF SHEET	CAL P.U.C. SHEET NO.	

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SAMPLE FORMS

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PG&E Gas and Electric
Advice Filing List
General Order 96-B, Section IV

Aglet
Agnews Developmental Center
Alcantar & Kahl
Ancillary Services Coalition
Anderson & Poole
Arizona Public Service Company
BART
BP Energy Company
Barkovich & Yap, Inc.
Bartle Wells Associates
Blue Ridge Gas
Braun & Associates
C & H Sugar Co.
CA Bldg Industry Association
CAISO
CLECA Law Office
CSC Energy Services
California Cotton Ginners & Growers Assn
California Energy Commission
California League of Food Processors
California Public Utilities Commission
Calpine
Cameron McKenna
Cardinal Cogen
Casner, Steve
Cerox
Chamberlain, Eric
Chevron Company
Chris, King
City of Glendale
City of Palo Alto
City of San Jose
Clean Energy Fuels
Coast Economic Consulting
Commerce Energy
Commercial Energy
Constellation
Constellation New Energy
Consumer Federation of California
Crossborder Energy
Davis Wright Tremaine LLP
Day Carter Murphy
Defense Energy Support Center
Department of Water Resources
Department of the Army
Dept of General Services
Division of Business Advisory Services
Douglas & Liddell
Douglass & Liddell
Downey & Brand
Duke Energy
Duncan, Virgil E.
Dutcher, John
Ellison Schneider & Harris LLP
Energy Management Services, LLC
FPL Energy Project Management, Inc.
Foster Farms
Foster, Wheeler, Martinez
Franciscan Mobilehome
G. A. Krause & Assoc.
GLJ Publications
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
Heeg, Peggy A.
Hitachi
Hogan Manufacturing, Inc.
Imperial Irrigation District
Innercite
International Power Technology
Intestate Gas Services, Inc.
J. R. Wood, Inc.
JTM, Inc.
Los Angeles Dept of Water & Power
Luce, Forward, Hamilton & Scripps LLP
MBMC, Inc.
MRW & Associates
Manatt Phelps Phillips
Matthew V. Brady & Associates
McKenzie & Associates
Meek, Daniel W.
Merced Irrigation District
Mirant
Modesto Irrigation District
Morgan Stanley
Morrison & Foerster
New United Motor Mfg., Inc.
Norris & Wong Associates
North Coast SolarResources
Northern California Power Association
Occidental Energy Marketing, Inc.
OnGrid Solar
PPL EnergyPlus, LLC
Pinnacle CNG Company
Praxair
R. W. Beck & Associates
RCS, Inc.
RMC Lonestar
Recon Research
SCD Energy Solutions
SCE
SESCO
SMUD
SPURR
Santa Fe Jets
Seattle City Light
Sempra Utilities
Sequoia Union HS Dist
Sierra Pacific Power Company
Silicon Valley Power
Smurfit Stone Container Corp
Southern California Edison Company
St. Paul Assoc.
Sunshine Design
Sutherland, Asbill & Brennan
TFS Energy
Tabors Caramanis & Associates
Tecogen, Inc.
Tiger Natural Gas, Inc.
Tioga Energy
TransCanada
Turlock Irrigation District
U S Borax, Inc.
United Cogen
Utility Cost Management
Utility Resource Network
Utility Specialists
Vandenberg Air Force
Verizon
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
White & Case
eMeter Corporation

Selected Legislation and Regulatory Mandates

Selected Legislation and Regulatory Mandates

- California AB 32 – Global Warming Solutions Act of 2006
- AB 1969, Yee. Electrical Corporations: Water Agencies (2006)
- SB 107, Simitian. Renewable energy: Public Interest Energy Research, Demonstration, and Development Program (2006)
- SB 380, Kehoe. Renewable Energy Resources (2008)
- Executive Order S-3-05 by Governor of the State of California
- CEQA Guidelines Section 15328 – Small Hydroelectric Categorical Exemption
- FERC Exemption of Small Hydroelectric Power Projects of 5 Megawatts or Less
- FERC Exemption of Small Conduit Hydroelectric Facilities

Assembly Bill No. 32

CHAPTER 488

An act to add Division 25.5 (commencing with Section 38500) to the Health and Safety Code, relating to air pollution.

[Approved by Governor September 27, 2006. Filed with Secretary of State September 27, 2006.]

LEGISLATIVE COUNSEL'S DIGEST

AB 32, Nunez. Air pollution: greenhouse gases: California Global Warming Solutions Act of 2006.

Under existing law, the State Air Resources Board (state board), the State Energy Resources Conservation and Development Commission (Energy Commission), and the California Climate Action Registry all have responsibilities with respect to the control of emissions of greenhouse gases, as defined, and the Secretary for Environmental Protection is required to coordinate emission reductions of greenhouse gases and climate change activity in state government.

This bill would require the state board to adopt regulations to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program, as specified. The bill would require the state board to adopt a statewide greenhouse gas emissions limit equivalent to the statewide greenhouse gas emissions levels in 1990 to be achieved by 2020, as specified. The bill would require the state board to adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions, as specified. The bill would authorize the state board to adopt market-based compliance mechanisms, as defined, meeting specified requirements. The bill would require the state board to monitor compliance with and enforce any rule, regulation, order, emission limitation, emissions reduction measure, or market-based compliance mechanism adopted by the state board, pursuant to specified provisions of existing law. The bill would authorize the state board to adopt a schedule of fees to be paid by regulated sources of greenhouse gas emissions, as specified.

Because the bill would require the state board to establish emissions limits and other requirements, the violation of which would be a crime, this bill would create a state-mandated local program.

The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

The people of the State of California do enact as follows:

SECTION 1. Division 25.5 (commencing with Section 38500) is added to the Health and Safety Code, to read:

DIVISION 25.5. CALIFORNIA GLOBAL WARMING SOLUTIONS ACT OF 2006

PART 1. GENERAL PROVISIONS

CHAPTER 1. TITLE OF DIVISION

38500. This division shall be known, and may be cited, as the California Global Warming Solutions Act of 2006.

CHAPTER 2. FINDINGS AND DECLARATIONS

38501. The Legislature finds and declares all of the following:

(a) Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems.

(b) Global warming will have detrimental effects on some of California's largest industries, including agriculture, wine, tourism, skiing, recreational and commercial fishing, and forestry. It will also increase the strain on electricity supplies necessary to meet the demand for summer air-conditioning in the hottest parts of the state.

(c) California has long been a national and international leader on energy conservation and environmental stewardship efforts, including the areas of air quality protections, energy efficiency requirements, renewable energy standards, natural resource conservation, and greenhouse gas emission standards for passenger vehicles. The program established by this division will continue this tradition of environmental leadership by placing California at the forefront of national and international efforts to reduce emissions of greenhouse gases.

(d) National and international actions are necessary to fully address the issue of global warming. However, action taken by California to reduce emissions of greenhouse gases will have far-reaching effects by encouraging other states, the federal government, and other countries to act.

(e) By exercising a global leadership role, California will also position its economy, technology centers, financial institutions, and businesses to benefit from national and international efforts to reduce emissions of greenhouse gases. More importantly, investing in the development of innovative and pioneering technologies will assist California in achieving the 2020 statewide limit on emissions of greenhouse gases established by this division and will provide an opportunity for the state to take a global economic and technological leadership role in reducing emissions of greenhouse gases.

(f) It is the intent of the Legislature that the State Air Resources Board coordinate with state agencies, as well as consult with the environmental justice community, industry sectors, business groups, academic institutions, environmental organizations, and other stakeholders in implementing this division.

(g) It is the intent of the Legislature that the State Air Resources Board consult with the Public Utilities Commission in the development of emissions reduction measures, including limits on emissions of greenhouse gases applied to electricity and natural gas providers regulated by the Public Utilities Commission in order to ensure that electricity and natural gas providers are not required to meet duplicative or inconsistent regulatory requirements.

(h) It is the intent of the Legislature that the State Air Resources Board design emissions reduction measures to meet the statewide emissions limits for greenhouse gases established pursuant to this division in a manner that minimizes costs and maximizes benefits for California's economy, improves and modernizes California's energy infrastructure and maintains electric system reliability, maximizes additional environmental and economic co-benefits for California, and complements the state's efforts to improve air quality.

(i) It is the intent of the Legislature that the Climate Action Team established by the Governor to coordinate the efforts set forth under Executive Order S-3-05 continue its role in coordinating overall climate policy.

Chapter 3. Definitions

38505. For the purposes of this division, the following terms have the following meanings:

(a) "Allowance" means an authorization to emit, during a specified year, up to one ton of carbon dioxide equivalent.

(b) "Alternative compliance mechanism" means an action undertaken by a greenhouse gas emission source that achieves the equivalent reduction of greenhouse gas emissions over the same time period as a direct emission reduction, and that is approved by the state board. "Alternative compliance mechanism" includes, but is not limited to, a flexible compliance schedule, alternative control technology, a process change, or a product substitution.

(c) "Carbon dioxide equivalent" means the amount of carbon dioxide by weight that would produce the same global warming impact as a given weight of another greenhouse gas, based on the best available science, including from the Intergovernmental Panel on Climate Change.

(d) "Cost-effective" or "cost-effectiveness" means the cost per unit of reduced emissions of greenhouse gases adjusted for its global warming potential.

(e) "Direct emission reduction" means a greenhouse gas emission reduction action made by a greenhouse gas emission source at that source.

(f) "Emissions reduction measure" means programs, measures, standards, and alternative compliance mechanisms authorized pursuant to this division, applicable to sources or categories of sources, that are designed to reduce emissions of greenhouse gases.

(g) "Greenhouse gas" or "greenhouse gases" includes all of the following gases: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexaflouride.

(h) "Greenhouse gas emissions limit" means an authorization, during a specified year, to emit up to a level of greenhouse gases specified by the state board, expressed in tons of carbon dioxide equivalents.

(i) "Greenhouse gas emission source" or "source" means any source, or category of sources, of greenhouse gas emissions whose emissions are at a level of significance, as determined by the state board, that its participation in the program established under this division will enable the state board to effectively reduce greenhouse gas emissions and monitor compliance with the statewide greenhouse gas emissions limit.

(j) "Leakage" means a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state.

(k) "Market-based compliance mechanism" means either of the following:

(1) A system of market-based declining annual aggregate emissions limitations for sources or categories of sources that emit greenhouse gases.

(2) Greenhouse gas emissions exchanges, banking, credits, and other transactions, governed by rules and protocols established by the state board, that result in the same greenhouse gas emission reduction, over the same time period, as direct compliance with a greenhouse gas emission limit or emission reduction measure adopted by the state board pursuant to this division.

(*l*) "State board" means the State Air Resources Board.

(m) "Statewide greenhouse gas emissions" means the total annual emissions of greenhouse gases in the state, including all emissions of greenhouse gases from the generation of electricity delivered to and consumed in California, accounting for transmission and distribution line losses, whether the electricity is generated in state or imported. Statewide emissions shall be expressed in tons of carbon dioxide equivalents.

(n) "Statewide greenhouse gas emissions limit" or "statewide emissions limit" means the maximum allowable level of statewide greenhouse gas emissions in 2020, as determined by the state board pursuant to Part 3 (commencing with Section 38850).

Chapter 4. Role of State Board

38510. The State Air Resources Board is the state agency charged with monitoring and regulating sources of emissions of greenhouse gases that cause global warming in order to reduce emissions of greenhouse gases.

PART 2. MANDATORY GREENHOUSE GAS EMISSIONS REPORTING

38530. (a) On or before January 1, 2008, the state board shall adopt regulations to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program.

(b) The regulations shall do all of the following:

(1) Require the monitoring and annual reporting of greenhouse gas emissions from greenhouse gas emission sources beginning with the sources or categories of sources that contribute the most to statewide emissions.

(2) Account for greenhouse gas emissions from all electricity consumed in the state, including transmission and distribution line losses from electricity generated within the state or imported from outside the state. This requirement applies to all retail sellers of electricity, including load-serving entities as defined in subdivision (j) of Section 380 of the Public Utilities Code and local publicly owned electric utilities as defined in Section 9604 of the Public Utilities Code.

(3) Where appropriate and to the maximum extent feasible, incorporate the standards and protocols developed by the California Climate Action Registry, established pursuant to Chapter 6 (commencing with Section 42800) of Part 4 of Division 26. Entities that voluntarily participated in the California Climate Action Registry prior to December 31, 2006, and have developed a greenhouse gas emission reporting program, shall not be required to significantly alter their reporting or verification program except as necessary to ensure that reporting is complete and verifiable for the purposes of compliance with this division as determined by the state board.

(4) Ensure rigorous and consistent accounting of emissions, and provide reporting tools and formats to ensure collection of necessary data.

(5) Ensure that greenhouse gas emission sources maintain comprehensive records of all reported greenhouse gas emissions.

(c) The state board shall do both of the following:

(1) Periodically review and update its emission reporting requirements, as necessary.

(2) Review existing and proposed international, federal, and state greenhouse gas emission reporting programs and make reasonable efforts to promote consistency among the programs established pursuant to this part and other programs, and to streamline reporting requirements on greenhouse gas emission sources.

PART 3. STATEWIDE GREENHOUSE GAS EMISSIONS LIMIT

38550. By January 1, 2008, the state board shall, after one or more public workshops, with public notice, and an opportunity for all interested parties to comment, determine what the statewide greenhouse gas emissions level was in 1990, and approve in a public hearing, a statewide greenhouse gas emissions limit that is equivalent to that level, to be achieved by 2020. In order to ensure the most accurate determination feasible, the state board shall evaluate the best available scientific, technological, and economic information on greenhouse gas emissions to determine the 1990 level of greenhouse gas emissions.

38551. (a) The statewide greenhouse gas emissions limit shall remain in effect unless otherwise amended or repealed.

(b) It is the intent of the Legislature that the statewide greenhouse gas emissions limit continue in existence and be used to maintain and continue reductions in emissions of greenhouse gases beyond 2020.

(c) The state board shall make recommendations to the Governor and the Legislature on how to continue reductions of greenhouse gas emissions beyond 2020.

PART 4. GREENHOUSE GAS EMISSIONS REDUCTIONS

38560. The state board shall adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions from sources or categories of sources, subject to the criteria and schedules set forth in this part.

38560.5. (a) On or before June 30, 2007, the state board shall publish and make available to the public a list of discrete early action greenhouse gas emission reduction measures that can be implemented prior to the measures and limits adopted pursuant to Section 38562.

(b) On or before January 1, 2010, the state board shall adopt regulations to implement the measures identified on the list published pursuant to subdivision (a).

(c) The regulations adopted by the state board pursuant to this section shall achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from those sources or categories of sources, in furtherance of achieving the statewide greenhouse gas emissions limit.

(d) The regulations adopted pursuant to this section shall be enforceable no later than January 1, 2010.

38561. (a) On or before January 1, 2009, the state board shall prepare and approve a scoping plan, as that term is understood by the state board, for achieving the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from sources or categories of sources of greenhouse gases by 2020 under this division. The state board shall consult with all state agencies with jurisdiction over sources of greenhouse gases, including the Public Utilities Commission and the State Energy Resources Conservation and Development Commission, on all elements of its plan that pertain to energy related matters including, but not limited to, electrical generation, load based-standards or requirements, the provision of reliable and affordable electrical service, petroleum refining, and statewide fuel supplies to ensure the greenhouse gas emissions reduction activities to be adopted and implemented by the state board are complementary, nonduplicative, and can be implemented in an efficient and cost-effective manner.

(b) The plan shall identify and make recommendations on direct emission reduction measures, alternative compliance mechanisms, market-based compliance mechanisms, and potential monetary and nonmonetary incentives for sources and categories of sources that the state board finds are necessary or desirable to facilitate the achievement of the maximum feasible and cost-effective reductions of greenhouse gas emissions by 2020.

(c) In making the determinations required by subdivision (b), the state board shall consider all relevant information pertaining to greenhouse gas emissions reduction programs in other states, localities, and nations, including the northeastern states of the United States, Canada, and the European Union.

(d) The state board shall evaluate the total potential costs and total potential economic and noneconomic benefits of the plan for reducing greenhouse gases to California's economy, environment, and public health, using the best available economic models, emission estimation techniques, and other scientific methods.

(e) In developing its plan, the state board shall take into account the relative contribution of each source or source category to statewide greenhouse gas emissions, and the potential for adverse effects on small businesses, and shall recommend a de minimis threshold of greenhouse gas emissions below which emission reduction requirements will not apply.

(f) In developing its plan, the state board shall identify opportunities for emission reductions measures from all verifiable and enforceable voluntary actions, including, but not limited to, carbon sequestration projects and best management practices.

(g) The state board shall conduct a series of public workshops to give interested parties an opportunity to comment on the plan. The state board shall conduct a portion of these workshops in regions of the state that have the most significant exposure to air pollutants, including, but not limited to, communities with minority populations, communities with low-income populations, or both.

(h) The state board shall update its plan for achieving the maximum technologically feasible and cost-effective reductions of greenhouse gas emissions at least once every five years.

38562. (a) On or before January 1, 2011, the state board shall adopt greenhouse gas emission limits and emission reduction measures by regulation to achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions in furtherance of achieving the statewide greenhouse gas emissions limit, to become operative beginning on January 1, 2012.

(b) In adopting regulations pursuant to this section and Part 5 (commencing with Section 38570), to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

(1) Design the regulations, including distribution of emissions allowances where appropriate, in a manner that is equitable, seeks to minimize costs and maximize the total benefits to California, and encourages early action to reduce greenhouse gas emissions.

(2) Ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities.

(3) Ensure that entities that have voluntarily reduced their greenhouse gas emissions prior to the implementation of this section receive appropriate credit for early voluntary reductions.

(4) Ensure that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions.

(5) Consider cost-effectiveness of these regulations.

(6) Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health.

(7) Minimize the administrative burden of implementing and complying with these regulations.

(8) Minimize leakage.

(9) Consider the significance of the contribution of each source or category of sources to statewide emissions of greenhouse gases.

(c) In furtherance of achieving the statewide greenhouse gas emissions limit, by January 1, 2011, the state board may adopt a regulation that establishes a system of market-based declining annual aggregate emission limits for sources or categories of sources that emit greenhouse gas emissions, applicable from January 1, 2012, to December 31, 2020, inclusive, that the state board determines will achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions, in the aggregate, from those sources or categories of sources.

(d) Any regulation adopted by the state board pursuant to this part or Part 5 (commencing with Section 38570) shall ensure all of the following:

(1) The greenhouse gas emission reductions achieved are real, permanent, quantifiable, verifiable, and enforceable by the state board.

(2) For regulations pursuant to Part 5 (commencing with Section 38570), the reduction is in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur.

(3) If applicable, the greenhouse gas emission reduction occurs over the same time period and is equivalent in amount to any direct emission reduction required pursuant to this division.

(e) The state board shall rely upon the best available economic and scientific information and its assessment of existing and projected technological capabilities when adopting the regulations required by this section.

(f) The state board shall consult with the Public Utilities Commission in the development of the regulations as they affect electricity and natural gas providers in order to minimize duplicative or inconsistent regulatory requirements.

(g) After January 1, 2011, the state board may revise regulations adopted pursuant to this section and adopt additional regulations to further the provisions of this division.

38563. Nothing in this division restricts the state board from adopting greenhouse gas emission limits or emission reduction measures prior to January 1, 2011, imposing those limits or measures prior to January 1, 2012, or providing early reduction credit where appropriate.

38564. The state board shall consult with other states, and the federal government, and other nations to identify the most effective strategies and methods to reduce greenhouse gases, manage greenhouse gas control programs, and to facilitate the development of integrated and cost-effective regional, national, and international greenhouse gas reduction programs.

38565. The state board shall ensure that the greenhouse gas emission reduction rules, regulations, programs, mechanisms, and incentives under its jurisdiction, where applicable and to the extent feasible, direct public and private investment toward the most disadvantaged communities in California and provide an opportunity for small businesses, schools, affordable housing associations, and other community institutions to participate in and benefit from statewide efforts to reduce greenhouse gas emissions.

PART 5. MARKET-BASED COMPLIANCE MECHANISMS

38570. (a) The state board may include in the regulations adopted pursuant to Section 38562 the use of market-based compliance mechanisms to comply with the regulations.

(b) Prior to the inclusion of any market-based compliance mechanism in the regulations, to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

(1) Consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution.

(2) Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants.

(3) Maximize additional environmental and economic benefits for California, as appropriate.

(c) The state board shall adopt regulations governing how market-based compliance mechanisms may be used by regulated entities subject to greenhouse gas emission limits and mandatory emission reporting requirements to achieve compliance with their greenhouse gas emissions limits.

38571. The state board shall adopt methodologies for the quantification of voluntary greenhouse gas emission reductions. The state board shall adopt regulations to verify and enforce any voluntary greenhouse gas emission reductions that are authorized by the state board for use to comply with greenhouse gas emission limits established by the state board. The adoption of methodologies is exempt from the rulemaking provisions of the Administrative Procedure Act (Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code).

38574. Nothing in this part or Part 4 (commencing with Section 38560) confers any authority on the state board to alter any programs administered by other state agencies for the reduction of greenhouse gas emissions.

PART 6. ENFORCEMENT

38580. (a) The state board shall monitor compliance with and enforce any rule, regulation, order, emission limitation, emissions reduction measure, or market-based compliance mechanism adopted by the state board pursuant to this division.

(b) (1) Any violation of any rule, regulation, order, emission limitation, emissions reduction measure, or other measure adopted by the state board pursuant to this division may be enjoined pursuant to Section 41513, and the violation is subject to those penalties set forth in Article 3 (commencing with Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 43025) of Part 5 of, Division 26.

(2) Any violation of any rule, regulation, order, emission limitation, emissions reduction measure, or other measure adopted by the state board pursuant to this division shall be deemed to result in an emission of an air contaminant for the purposes of the penalty provisions of Article 3 (commencing with Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 43025) of Part 5 of, Division 26.

(3) The state board may develop a method to convert a violation of any rule, regulation, order, emission limitation, or other emissions reduction measure adopted by the state board pursuant to this division into the number of days in violation, where appropriate, for the purposes of the penalty provisions of Article 3 (commencing with Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 43025) of Part 5 of, Division 26.

(c) Section 42407 and subdivision (i) of Section 42410 shall not apply to this part.

PART 7. MISCELLANEOUS PROVISIONS

38590. If the regulations adopted pursuant to Section 43018.5 do not remain in effect, the state board shall implement alternative regulations to control mobile sources of greenhouse gas emissions to achieve equivalent or greater reductions.

38591. (a) The state board, by July 1, 2007, shall convene an environmental justice advisory committee, of at least three members, to advise it in developing the scoping plan pursuant to Section 38561 and any other pertinent matter in implementing this division. The advisory committee shall be comprised of representatives from communities in the state with the most significant exposure to air pollution, including, but not limited to, communities with minority populations or low-income populations, or both.

(b) The state board shall appoint the advisory committee members from nominations received from environmental justice organizations and community groups.

(c) The state board shall provide reasonable per diem for attendance at advisory committee meetings by advisory committee members from nonprofit organizations.

(d) The state board shall appoint an Economic and Technology Advancement Advisory Committee to advise the state board on activities that will facilitate investment in and implementation of technological research and development opportunities, including, but not limited to, identifying new technologies, research, demonstration projects, funding opportunities, developing state, national, and international partnerships and technology transfer opportunities, and identifying and assessing research and advanced technology investment and incentive opportunities that will assist in the reduction of greenhouse gas emissions. The committee may also advise the state board on state, regional, national, and international economic and technological developments related to greenhouse gas emission reductions.

38592. (a) All state agencies shall consider and implement strategies to reduce their greenhouse gas emissions.

(b) Nothing in this division shall relieve any person, entity, or public agency of compliance with other applicable federal, state, or local laws or regulations, including state air and water quality requirements, and other requirements for protecting public health or the environment.

38593. (a) Nothing in this division affects the authority of the Public Utilities Commission.

(b) Nothing in this division affects the obligation of an electrical corporation to provide customers with safe and reliable electric service.

38594. Nothing in this division shall limit or expand the existing authority of any district, as defined in Section 39025.

38595. Nothing in this division shall preclude, prohibit, or restrict the construction of any new facility or the expansion of an existing facility subject to regulation under this division, if all applicable requirements are met and the facility is in compliance with regulations adopted pursuant to this division.

38596. The provisions of this division are severable. If any provision of this division or its application is held invalid, that invalidity shall not affect other provisions or applications that can be given effect without the invalid provision or application.

38597. The state board may adopt by regulation, after a public workshop, a schedule of fees to be paid by the sources of greenhouse gas emissions regulated pursuant to this division, consistent with Section 57001. The revenues collected pursuant to this section, shall be deposited into the Air Pollution Control Fund and are available upon appropriation, by the Legislature, for purposes of carrying out this division.

38598. (a) Nothing in this division shall limit the existing authority of a state entity to adopt and implement greenhouse gas emissions reduction measures.

(b) Nothing in this division shall relieve any state entity of its legal obligations to comply with existing law or regulation.

38599. (a) In the event of extraordinary circumstances, catastrophic events, or threat of significant economic harm, the Governor may adjust the applicable deadlines for individual regulations, or for the state in the aggregate, to the earliest feasible date after that deadline.

(b) The adjustment period may not exceed one year unless the Governor makes an additional adjustment pursuant to subdivision (a).

(c) Nothing in this section affects the powers and duties established in the California Emergency Services Act (Chapter 7 (commencing with Section 8550) of Division 1 of Title 2 of the Government Code).

(d) The Governor shall, within 10 days of invoking subdivision (a), provide written notification to the Legislature of the action undertaken.

SEC. 2 No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because the only costs that

Assembly Bill No. 1969

CHAPTER 731

An act to add Section 399.20 to the Public Utilities Code, relating to energy.

[Approved by Governor September 29, 2006. Filed with Secretary of State September 29, 2006.]

LEGISLATIVE COUNSEL'S DIGEST

AB 1969, Yee. Electrical corporations: water agencies.

(1) The Public Utilities Act requires the Public Utilities Commission to review and adopt a procurement plan and a renewable energy procurement plan for each electrical corporation pursuant to the California Renewables Portfolio Standard Program. The program requires that a retail seller of electricity, including electrical corporations, community choice aggregators, and electric service providers, but not including local publicly owned electric utilities, purchase a specified minimum percentage of electricity generated by eligible renewable energy resources, as defined, in any given year as a specified percentage of total kilowatthours sold to retail end-use customers each calendar year (renewables portfolio standard).

Existing law, except as specified, requires every electric service provider, as defined, to develop a standard contract or tariff providing for net energy metering, and to make this contract or tariff available to eligible customer generators, upon request, on a first-come-first-served basis until the total rated generating capacity used by eligible customer generators exceeds 0.5% of the electric service provider's aggregate customer peak demand.

This bill would require every electrical corporation to file with the commission a standard tariff for renewable energy output produced at an electric generation facility, as defined, that, among other things, is an eligible renewable energy resource. The bill would require the electrical corporation to make this tariff available to public water or wastewater agencies that own and operate an electric generation facility within the service territory of the electrical corporation, upon request, on a first-come-first-served basis, until the combined statewide cumulative rated generating capacity of those electric generation facilities equals 250 megawatts. The bill would specify that each electrical corporation would only be required to offer service or contracts under the bill until that electrical corporation meets its proportionate share of the 250 megawatts based on the ratio of its peak demand to the total statewide peak demand of all electrical corporations.

The bill would provide that, upon approval by the commission, any tariff or contract authorized by the bill may be made available to an electric generation facility that has an effective capacity of not more than 1.5 megawatts if that electrical generation facility otherwise complies with the bill.

(2) Under existing law, the failure to file a required tariff, or a violation of an order or direction of the commission, including a commission-approved tariff, is a crime.

Because the bill would require electrical corporations to file new tariffs, the bill would impose a state-mandated local program by creating new crimes.

(3) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

The people of the State of California do enact as follows:

SECTION 1. The Legislature finds and declares all of the following:

(a) The health of the state's economy depends upon reliable, affordable, adequate, and environmentally sound supplies of energy and water.

(b) The state's rapidly growing population is increasing the demand for water and the energy needed to deliver and treat it.

(c) The state's water-related electricity demand accounts for nearly 20 percent of the state's overall electricity consumption.

(d) Despite improvements in power plant licensing, successful energy efficiency programs, and continued technological advancements, the development of new energy supplies is not keeping pace with the state's increasing demand. Moreover, the development of new renewable resources has been slower than anticipated and limited by existing transmission constraints.

(e) Unless properly managed on a statewide basis, water-related electricity demand could ultimately affect the reliability of the electric system.

(f) Public water and wastewater facilities are strategically located and interconnected to the electric transmission system in a manner that optimizes the deliverability of electricity generated at those facilities to load centers.

(g) Renewable energy produced at public water and wastewater facilities will reduce the demand for the production of nonrenewable energy needed to serve water-related electricity demand.

SEC. 2. Section 399.20 is added to the Public Utilities Code, to read:

399.20. (a) It is the policy of this state and the intent of the Legislature to encourage energy production from renewable resources at public water and wastewater facilities in an amount commensurate with water-related electricity demand.

(b) As used in this section, "electric generation facility" means an electric generation facility, owned and operated by a public water or wastewater agency that is a retail customer of an electrical corporation, and that meets all of the following criteria:

(1) Has an effective capacity of not more than one megawatt and is located on or adjacent to a water or wastewater facility owned and operated by the public water or wastewater agency.

(2) Is interconnected and operates in parallel with the electric transmission and distribution grid.

(3) Is sized to offset part or all of the electricity demand of the public water or wastewater agency.

(4) Is strategically located and interconnected to the electric transmission system in a manner that optimizes the deliverability of electricity generated at the facility to load centers.

(5) Is an eligible renewable energy resource, as defined in Section 399.12.

(c) Every electrical corporation shall file with the commission a standard tariff for renewable energy output produced at an electric generation facility.

(d) The tariff shall provide for payment for every kilowatthour of renewable energy output produced at an electric generation facility at the market price as determined by the commission pursuant to Section 399.15 for a period of 10, 15, or 20 years, as authorized by the commission.

(e) Every electrical corporation shall make this tariff available to public water or wastewater agencies that own and operate an electric generation facility within the service territory of the electrical corporation, upon request, on a first-come-first-served basis, until the combined statewide cumulative rated generating capacity of those electric generation facilities equals 250 megawatts. An electrical corporation may make the terms of the tariff available to public water or wastewater agencies in the form of a standard contract subject to commission approval. Each electrical corporation shall only be required to offer service or contracts under this section until that electrical corporation meets its proportionate share of the 250 megawatts based on the ratio of its peak demand to the total statewide peak demand of all electrical corporations.

(f) Every kilowatthour of renewable energy output produced by the electric generation facility shall count toward the electrical corporation's renewable portfolio standard annual procurement targets for purposes of paragraph (1) of subdivision (b) of Section 399.15.

(g) The physical generating capacity of an electric generation facility shall count toward the electrical corporation's resource adequacy requirement for purposes of Section 380.

(h) Upon approval by the commission, any tariff or contract authorized by this section may be made available to an electric generation facility that has an effective capacity of not more than 1.5 megawatts if that electrical generation facility otherwise complies with all of the provisions of this section.

SEC. 3. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

O

Senate Bill No. 107

CHAPTER 464

An act to amend Sections 25620.1, 25740, 25741, 25742, 25743, 25746, and 25751 of, to add Sections 25470.5 and 25744.5 to, and to repeal Sections 25745 and 25749 of, the Public Resources Code, and to amend Sections 387, 399.11, 399.12, 399.13, 399.14, and 399.15 of, to add Article 9 (commencing with Section 635) to Chapter 3 of Part 1 of Division 1 of, to add and repeal Section 2854 of, and to repeal and add Section 399.16 of, the Public Utilities Code, relating to energy.

[Approved by Governor September 26, 2006. Filed with Secretary of State September 26, 2006.]

LEGISLATIVE COUNSEL'S DIGEST

SB 107, Simitian. Renewable energy: Public Interest Energy Research, Demonstration, and Development Program.

(1) Existing law expresses the intent of the Legislature, in establishing the Renewable Energy Resources Program, to increase the amount of renewable electricity generated per year, so that it equals at least 17% of the total electricity generated for consumption in California per year by 2006.

This bill would revise and recast that intent language so that the amount of electricity generated per year from eligible renewable energy resources is increased to an amount that equals at least 20% of the total electricity sold to retail customers in California per year by December 31, 2010. The bill would make conforming changes related to this provision.

(2) The Public Utilities Act imposes various duties and responsibilities on the California Public Utilities Commission (CPUC) with respect to the purchase of electricity and requires the CPUC to review and adopt a procurement plan and a renewable energy procurement plan for each electrical corporation pursuant to the California Renewables Portfolio Standard Program. The program requires that a retail seller of electricity, including electrical corporations, community choice aggregators, and electric service providers, but not including local publicly owned electric utilities, purchase a specified minimum percentage of electricity generated by eligible renewable energy resources, as defined, in any given year as a specified percentage of total kilowatthours sold to retail end-use customers each calendar year (renewables portfolio standard). The renewables portfolio standard requires each electrical corporation to increase its total procurement of eligible renewable energy resources by at least an additional 1% of retail sales per year so that 20% of its retail sales are procured from eligible renewable energy resources no later than December 31, 2017.

This bill would instead require that each retail seller, as defined, increase its total procurement of eligible renewable energy resources by at least an additional 1% of retail sales per year so that 20% of its retail sales are procured from eligible renewable energy resources no later than December 31, 2010.

(3) Existing law requires the State Energy Resources Conservation and Development Commission (Energy Commission) to certify eligible renewable energy resources, to design and implement an accounting system to verify compliance with the renewables portfolio standard by retail sellers, and to allocate and award supplemental energy payments to cover above-market costs of renewable energy.

This bill would require the Energy Commission, if it provides funding for a regional accounting system to verify compliance with the renewables portfolio standard by retail sellers, to recover all costs from user fees. The bill would require the Energy Commission to develop tracking, accounting, verification, and enforcement mechanisms for renewable energy credits, as defined. The bill would specify that facilities located out of state shall not be eligible for supplemental energy payments unless certain requirements are met, and would limit awards to those facilities to 10% of funds available. The bill would require that deliveries of electricity from an eligible renewable energy resource under any electricity purchase agreement with a retail seller executed before January 1, 2002, be tracked and included in the baseline quantity of eligible renewable energy resources of the purchasing retail seller. The bill would require that electricity generated pursuant to a prescribed federal act and pursuant to a purchase contract executed on or after January 1, 2002, count towards the renewables portfolio standard requirements of the retail seller. The bill would provide for the tracking of deliveries under these purchase contracts through a prescribed accounting system. The bill would make other technical and conforming changes.

Existing law provides that if supplemental energy payments from the Energy Commission, in combination with the market prices approved by the CPUC, are insufficient to cover any above-market costs of eligible renewable energy resources, the CPUC is required to allow a retail seller to limit its annual procurement obligation to the quantity of eligible renewable energy resources that can be procured with available supplemental energy payments.

This bill would require the CPUC to adopt flexible rules allowing a retail seller to limit its annual procurement obligation to the quantity of eligible renewable energy resources that can be delivered by existing transmission if the CPUC finds that the retail seller has undertaken all reasonable efforts to utilize flexible delivery points, ensure the availability of any needed transmission capacity, and, if an electric corporation, to construct needed transmission facilities.

(4) The Public Utilities Act permits the Energy Commission to consider an electric generating facility that is located outside the state to be an eligible renewable energy resource if it meets specific criteria.

This bill would delete that provision within the act and would amend the definition of an “in-state renewable electricity generation facility” within related provisions prescribing duties of the Energy Commission to encompass certain facilities located outside the state.

(5) Under existing law, the governing board of a local publicly owned electric utility is responsible for implementing and enforcing a renewables portfolio standard that recognizes the intent of the Legislature to encourage renewable energy resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement. Existing law requires the governing board of a local publicly owned electric utility to annually report certain information relative to renewable energy resources to its customers.

This bill would additionally require that the governing board of a local publicly owned electric utility annually report the utility’s status in implementing a renewables portfolio standard and progress toward attaining the standard to its customers and to report to the Energy Commission the information that the governing board is required to annually report to their customers. These additional reporting requirements would thereby impose a state-mandated local program.

(6) Under the Public Utilities Act, the CPUC requires electrical corporations to identify a separate rate component to fund programs that enhance system reliability and provide in-state benefits. This rate component is a nonbypassable element of local distribution and collected on the basis of usage. The funds are collected to support cost-effective energy efficiency and conservation activities, public interest research and development not adequately provided by competitive and regulated markets, and renewable energy resources (renewable energy public goods charge). Existing law requires the Energy Commission to transfer funds collected from the renewable energy public goods charge into the Renewable Resource Trust Fund and establishes certain accounts in the fund to carry out certain renewable energy purposes.

This bill would require the Energy Commission, in carrying out the renewable energy resources program, to optimize public investment and ensure that the most cost-effective and efficient investments in renewable energy resources are vigorously pursued with a long-term goal of achieving a fully competitive and self-sustaining supply of electricity generated from renewable sources. The bill would state that a near term objective of the program is to increase the quantity of electricity generated by in-state renewable electricity generation facilities, while protecting system reliability, fostering resource diversity, and obtaining the greatest environmental benefits for California residents with an additional objective to identify and support emerging renewable energy technologies that have the greatest near-term commercial promise and that merit targeted assistance. The bill would make legislative recommendations for allocations among specified renewable energy resources.

(7) Under existing law, 51.5% of the money collected as part of the renewable energy public goods charge is required to be used for programs

designed to foster the development of new in-state renewable electricity generation facilities, and to secure for the state the environmental, economic, and reliability benefits that operation of those facilities will provide. Existing law also provides that any of those funds used for new in-state renewable electricity generation facilities are required to be expended in accordance with a specified report of the Energy Commission to the Legislature, subject to certain requirements, including the awarding of supplemental energy payments.

This bill would require that these funds be awarded only to a project that is selected by an electrical corporation pursuant to a competitive solicitation procedure found by the CPUC to comply with the California Renewables Portfolio Standard Program and that the project participant has entered into an electricity purchase agreement resulting from that solicitation that is approved by the CPUC. The bill would authorize certain projects supplying electricity to retail sellers, as defined, to the extent the retail seller is servicing load that is within the distribution area of an electrical corporation and subject to the renewable energy public goods charge, to receive supplemental energy payments under certain circumstances. The bill would prohibit the Energy Commission from awarding supplemental energy payments for the sale or purchase of renewable energy credits or to service load that is not subject to the renewable energy public goods charge. The bill would incorporate the modified definition of an “in-state renewable electricity generation facility.”

(8) Existing law requires that 20% of the funds collected as part of the renewable energy public goods charge be used for a program designed to improve the competitiveness of existing in-state renewable electricity generation facilities and to secure for the state specified benefits.

This bill would reduce that amount to 10% of the funds collected and specify conditions under which certain facilities would be eligible for funding.

(9) Existing law requires that $17\frac{1}{2}$% of the funds collected as part of the renewable energy public goods charge be deposited into the Emerging Renewables Resources Account, and be used for a multiyear, consumer-based program to foster the development of emerging renewable technologies in distributed generation applications.

Existing law requires the Energy Commission, by January 1, 2008, and in consultation with the CPUC, local publicly owned electric utilities, and interested members of the public, to establish and thereafter revise eligibility criteria for solar energy systems, as defined, and to establish conditions for ratepayer funded incentives that are applicable to the California Solar Initiative, as defined.

This bill would require that the Energy Commission, in allocating and using moneys in the Emerging Renewables Resources Account and the Renewable Resource Trust Fund to fund photovoltaic and solar thermal electric technologies, to utilize the eligibility criteria and conditions for solar energy systems that are applicable to the California Solar Initiative.

(10) Existing law establishes the Customer-Credit Renewable Resource Purchases Account in the Renewable Resource Trust Fund, requires that 10% of the money collected under the renewable energy public goods charge be deposited into the account and be used for credits to customers that entered into a direct transaction on or before September 20, 2001, for purchases of electricity produced by registered in-state renewable electricity generating facilities.

This bill would delete these provisions.

(11) Existing law requires the use of standard terms and conditions by all electrical corporations in contracting for eligible renewable energy resources.

This bill would require that those terms and conditions include the requirement that, no later than 6 months after the CPUC's approval of an electricity purchase agreement, the following information about the agreement be disclosed by the CPUC: party names, resource type, project location, and project capacity.

(12) This bill would require an electrical corporation or local publicly owned electric utility to adopt certain strategies in a long-term plan or a procurement plan, as applicable, to achieve efficiency in the use of fossil fuels and to address carbon emissions, as specified.

(13) This bill would delete certain obsolete and duplicative provisions and make technical and conforming changes.

(14) This bill would require the CPUC, in consultation with the Energy Commission, to review the impact of allowing supplemental energy payments to be applied toward contracts for the procurement of eligible renewable energy resources that are of a duration of less than 10 years, and, by June 30, 2007, to report to the Legislature with the results of the review, including certain matters. The bill would require the PUC to report to the Legislature, on or before January 1, 2008, on the feasibility, desirability, and design of performance-based incentives for solar energy systems of less than 30 kilowatts.

(15) Existing law establishes the Public Interest Research, Development, and Demonstration Fund in the State Treasury, and provides that the money collected by the public goods charge to support public interest research and development not adequately provided by competitive and regulated markets, be deposited in the fund for use by the Energy Commission to develop, implement, and administer the Public Interest Research, Development, and Demonstration Program to develop technologies which will improve environmental quality, enhance electrical system reliability, increase efficiency of energy-using technologies, lower electrical system costs, or provide other tangible benefits. The Energy Commission is required to adopt a portfolio approach for the program that accomplishes specified objectives.

This bill would state that the general goal of the program is to develop, and help bring to market, energy technologies that provide increased environmental benefits, greater system reliability, and lower system costs, and that provide tangible benefits to electrical utility customers through specified investments. The bill would require that the portfolio approach used by the Energy Commission additionally ensure an open project selection process, encourage the awarding of research funding for a diverse type of research as well as a diverse award recipient base, equally considers research proposals from the public and private sectors, and be coordinated with other related research programs.

(16) Existing law makes a violation of the Public Utilities Act or a violation of an order of the CPUC a crime.

Certain of the provisions of this bill are a part of the act and an order of the CPUC would be required to implement these provisions. Because a violation of the provisions of the bill that are part of the act or of any CPUC order implementing these provisions would be a crime, this bill would impose a state-mandated local program by creating new crimes.

(17) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that with regard to certain mandates no reimbursement is required by this act for a specified reason.

With regard to any other mandates, this bill would provide that, if the Commission on State Mandates determines that the bill contains costs so mandated by the state, reimbursement for those costs shall be made pursuant to the statutory provisions noted above.

The people of the State of California do enact as follows:

SECTION 1. Section 25620.1 of the Public Resources Code is amended to read:

25620.1. (a) The commission shall develop, implement, and administer the Public Interest Research, Development, and Demonstration Program that is hereby created. The program shall include a full range of research, development, and demonstration activities that, as determined by the commission, are not adequately provided for by competitive and regulated markets. The commission shall administer the program consistent with the policies of this chapter.

(b) The general goal of the program is to develop, and help bring to market, energy technologies that provide increased environmental benefits, greater system reliability, and lower system costs, and that provide tangible benefits to electrical utility customers through investments in the following:

(1) Advanced electricity and natural gas transportation technologies that reduce air pollution and emissions of greenhouse gases beyond applicable standards, and that benefit electricity and natural gas ratepayers.

(2) Increased energy efficiency in buildings, appliances, lighting, and other applications beyond applicable standards, and that benefit electrical utility customers.

(3) Advanced electricity generation technologies that exceed applicable standards to increase reductions in emissions of greenhouse gases from electricity generation, and that benefit electric utility customers.

(4) Advanced electricity technologies that reduce or eliminate consumption of water or other finite resources, increase use of renewable energy resources, or improve transmission or distribution of electricity generated from renewable energy resources.

(c) To achieve the goals established in subdivision (b), the commission shall adopt a portfolio approach for the program that does all of the following:

(1) Effectively balances the risks, benefits, and time horizons for various activities and investments that will provide tangible energy or environmental benefits for California electricity customers.

(2) Emphasizes innovative energy supply and end-use technologies, focusing on their reliability, affordability, and environmental attributes.

(3) Includes projects that have the potential to enhance transmission and distribution capabilities.

(4) Includes projects that have the potential to enhance the reliability, peaking power, and storage capabilities of renewable energy.

(5) Demonstrates a balance of benefits to all sectors that contribute to the funding under Section 399.8 of the Public Utilities Code.

(6) Addresses key technical and scientific barriers.

(7) Demonstrates a balance between short-term, mid-term, and long-term potential.

(8) Ensures that prior, current, and future research not be unnecessarily duplicated.

(9) Provides for the future market utilization of projects funded through the program.

(10) Ensures an open project selection process and encourages the awarding of research funding for a diverse type of research as well as a diverse award recipient base and equally considers research proposals from the public and private sectors.

(11) Coordinates with other related research programs.

(d) The term "award," as used in this chapter, may include, but is not limited to, contracts, grants, interagency agreements, loans, and other financial agreements designed to fund public interest research, demonstration, and development projects or programs.

SEC. 2. Section 25740 of the Public Resources Code is amended to read:

25740. It is the intent of the Legislature in establishing this program, to increase the amount of electricity generated from eligible renewable energy resources per year, so that it equals at least 20 percent of total retail sales of electricity in California per year by December 31, 2010.

SEC. 3. Section 25741 of the Public Resources Code is amended to read:

25741. As used in this chapter, the following terms have the following meaning:

(a) "Delivered" and "delivery" mean the electricity output of an in-state renewable electricity generation facility that is used to serve end-use retail customers located within the state. Subject to verification by the accounting system established by the commission pursuant to subdivision (b) of Section 399.13 of the Public Utilities Code, electricity shall be deemed delivered if it is either generated at a location within the state, or is scheduled for consumption by California end-use retail customers. Subject to criteria adopted by the commission, electricity generated by an eligible renewable energy resource may be considered "delivered" regardless of whether the electricity is generated at a different time from consumption by a California end-use customer.

(b) "In-state renewable electricity generation facility" means a facility that meets all of the following criteria:

(1) The facility uses biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current, and any additions or enhancements to the facility using that technology.

(2) The facility satisfies one of the following requirements:

(A) The facility is located in the state or near the border of the state with the first point of connection to the transmission network within this state and electricity produced by the facility is delivered to an in-state location.

(B) The facility has its first point of interconnection to the transmission network outside the state and satisfies all of the following requirements:

(i) It is connected to the transmission network within the Western Electricity Coordinating Council (WECC) service territory.

(ii) It commences initial commercial operation after January 1, 2005.

(iii) Electricity produced by the facility is delivered to an in-state location.

(iv) It will not cause or contribute to any violation of a California environmental quality standard or requirement.

(v) If the facility is outside of the United States, it is developed and operated in a manner that is as protective of the environment as a similar facility located in the state.

(vi) It participates in the accounting system to verify compliance with the renewables portfolio standard by retail sellers, once established by the Energy Commission pursuant to subdivision (b) of Section 399.13 of the Public Utilities Code.

(C) The facility meets the requirements of clauses (i), (iii), (iv), (v), and (vi) in subparagraph (B), but does not meet the requirements of clause (ii) because it commences initial operation prior to January 1, 2005, if the facility satisfies either of the following requirements:

(i) The electricity is from incremental generation resulting from expansion or repowering of the facility.

(ii) The facility has been part of the existing baseline of eligible renewable energy resources of a retail seller established pursuant to paragraph (2) of subdivision (b) of Section 399.15 of the Public Utilities Code.

(3) For the purposes of this subdivision, “solid waste conversion” means a technology that uses a noncombustion thermal process to convert solid waste to a clean-burning fuel for the purpose of generating electricity, and that meets all of the following criteria:

(A) The technology does not use air or oxygen in the conversion process, except ambient air to maintain temperature control.

(B) The technology produces no discharges of air contaminants or emissions, including greenhouse gases as defined in Section 42801.1 of the Health and Safety Code.

(C) The technology produces no discharges to surface or groundwaters of the state.

(D) The technology produces no hazardous wastes.

(E) To the maximum extent feasible, the technology removes all recyclable materials and marketable green waste compostable materials from the solid waste stream prior to the conversion process and the owner or operator of the facility certifies that those materials will be recycled or composted.

(F) The facility at which the technology is used is in compliance with all applicable laws, regulations, and ordinances.

(G) The technology meets any other conditions established by the commission.

(H) The facility certifies that any local agency sending solid waste to the facility diverted at least 30 percent of all solid waste it collects through solid waste reduction, recycling, and composting. For purposes of this paragraph, “local agency” means any city, county, or special district, or subdivision thereof, which is authorized to provide solid waste handling services.

(c) “Procurement entity” means any person or corporation that enters into an agreement with a retail seller to procure eligible renewable energy resources pursuant to subdivision (f) of Section 399.14 of the Public Utilities Code.

(d) “Renewable energy public goods charge” means that portion of the nonbypassable system benefits charge authorized to be collected and to be transferred to the Renewable Resource Trust Fund pursuant to the Reliable Electric Service Investments Act (Article 15 (commencing with Section 399) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code).

(e) “Report” means the report entitled “Investing in Renewable Electricity Generation in California” (June 2001, Publication Number P500-00-022) submitted to the Governor and the Legislature by the commission.

(f) “Retail seller” means a “retail seller” as defined in Section 399.12 of the Public Utilities Code.

SEC. 4. Section 25740.5 is added to the Public Resources Code, to read:

25740.5. (a) The commission shall optimize public investment and ensure that the most cost-effective and efficient investments in renewable energy resources are vigorously pursued.

(b) The commission's long-term goal shall be a fully competitive and self-sustaining supply of electricity generated from renewable sources.

(c) The program objective shall be to increase, in the near term, the quantity of California's electricity generated by in-state renewable electricity generation facilities, while protecting system reliability, fostering resource diversity, and obtaining the greatest environmental benefits for California residents.

(d) An additional objective of the program shall be to identify and support emerging renewable technologies in distributed generation applications that have the greatest near-term commercial promise and that merit targeted assistance.

(e) The Legislature recommends allocations among all of the following:

(1) (A) Except as provided in subparagraph (B), production incentives for new in-state renewable electricity generation facilities, including repowered or refurbished facilities.

(B) Allocations shall not be made for electricity that is generated by an in-state renewable electricity generation facility that remains under an electricity purchase contract with an electrical corporation originally entered into prior to September 24, 1996, whether amended or restated thereafter.

(C) Notwithstanding subparagraph (B), production incentives may be allowed in any month for incremental new electricity generated by an in-state renewable electricity generation facility that is repowered or refurbished, where the electricity is delivered under an electricity purchase contract with an electrical corporation originally entered into prior to September 24, 1996, whether amended or restated thereafter, if all of the following occur:

(i) The facility's electricity purchase contract provides that all electricity delivered and sold under the contract is paid at a price that does not exceed the Public Utilities Commission approved short-run avoided cost of energy.

(ii) Either of the following is true:

(I) The electricity purchase contract is amended to provide that the kilowatthours used to determine the capacity payment in any time-of-delivery period in any month under the contract shall be equal to the actual kilowatthour production, but no greater than the five-year average of the kilowatthours delivered for the corresponding time-of-delivery period and month, in the years 1994 to 1998, inclusive.

(II) The facility's installed capacity as of December 31, 1998, is less than 75 percent of the nameplate capacity as stated in the electricity purchase contract, the electricity purchase contract is amended to provide that the kilowatthours used to determine the capacity payment in any time-of-delivery period in any month under the contract shall be equal to the actual kilowatthour production, but no greater than the product of the five-year average of the kilowatthours delivered for the corresponding time-of-delivery period and month, in the years 1994 to 1998, inclusive, and the ratio of installed capacity as of December 31 of the previous year, but not to exceed contract nameplate capacity, to the installed capacity as of December 31, 1998.

(iii) The production incentive is payable only with respect to the kilowatthours delivered in a particular month that exceeds the corresponding five-year average calculated pursuant to clause (ii).

(2) Rebates, buydowns, or equivalent incentives for emerging renewable technologies.

(3) Customer education.

(4) Incentives for reducing fuel costs, that are confirmed to the satisfaction of the commission, at solid fuel biomass energy facilities in order to provide demonstrable environmental and public benefits, including improved air quality.

(5) Solar thermal generating resources that enhance the environmental value or reliability of the electrical system and that require financial assistance to remain economically viable, as determined by the commission. The commission may require financial disclosure from applicants for purposes of this paragraph.

(6) Specified fuel cell technologies, if the commission makes all of the following findings:

(A) The specified technologies have similar or better air pollutant characteristics than renewable technologies in the report made pursuant to Section 25748.

(B) The specified technologies require financial assistance to become commercially viable by reference to wholesale generation prices.

(C) The specified technologies could contribute significantly to the infrastructure development or other innovation required to meet the long-term objective of a self-sustaining, competitive supply of electricity generated from renewable sources.

(7) Existing wind-generating resources, if the commission finds that the existing wind-generating resources are a cost-effective source of reliable energy and environmental benefits compared with other in-state renewable electricity generation facilities, and that the existing wind-generating resources require financial assistance to remain economically viable. The commission may require financial disclosure from applicants for the purposes of this paragraph.

(f) Notwithstanding any other provision of law, moneys collected for renewable energy pursuant to Article 15 (commencing with Section 399) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code shall be transferred to the Renewable Resource Trust Fund. Moneys collected between January 1, 2007, and January 1, 2012, shall be used for the purposes specified in this chapter.

SEC. 5. Section 25742 of the Public Resources Code is amended to read:

25742. (a) Ten percent of the funds collected pursuant to the renewable energy public goods charge shall be used for programs that are designed to achieve fully competitive and self-sustaining existing in-state renewable electricity generation facilities, and to secure for the state the environmental, economic, and reliability benefits that continued operation of those facilities will provide during the 2007–2011 investment cycle. Eligibility for incentives under this section shall be limited to those technologies found eligible for funds by the commission pursuant to paragraphs (4), (5), and (7) of subdivision (e) of Section 25740.5.

(b) Any funds used to support in-state renewable electricity generation facilities pursuant to this section shall be expended in accordance with the provisions of this chapter, including the following conditions:

(1) The commission shall establish a production incentive, which shall not exceed payment caps established by the commission, representing the difference between target prices and the price paid for electricity, if sufficient funds are available. If there are insufficient funds in any payment period to pay either the difference between the target and price paid for electricity or the payment caps, production incentives shall be based on the amount determined by dividing available funds by eligible generation.

(2) The commission may establish a time-differentiated incentive structure that encourages plants to run the maximum feasible amount of time and that provides a higher incentive when the plants are receiving the lowest price.

(3) The commission may consider inflation and production costs.

(c) Facilities that are eligible to receive funding pursuant to this section shall be registered in accordance with criteria developed by the commission and those facilities shall not receive payments for any electricity produced that is used on site.

(d) (1) The commission shall award funding to eligible facilities based on a facility's individual need. In assessing a facility's individual need, the commission shall, to the extent feasible, consider all of the following:

(A) The amount of the funds being considered for an award to the facility.

(B) The cumulative amount of funds the facility has received previously from the commission and other state sources.

(C) The value of any current federal or state tax credits.

(D) The facility's contract price for energy and capacity.

(E) The likelihood that the award will make the facility competitive and self-sustaining within the 2007–2011 investment cycle.

(F) Any other criteria as determined by the commission.

(2) The assessment shall also consider the public benefits provided by the operation of the facility.

(3) The commission shall use its assessment of the facility's individual need to determine the value of an award to the public relative to other renewable energy investment alternatives.

(4) The commission shall compile its findings and report them to the Legislature in the reports prepared pursuant to Section 25748.

SEC. 6. Section 25743 of the Public Resources Code is amended to read:

25743. (a) Fifty-one and one-half percent of the money collected pursuant to the renewable energy public goods charge shall be used for programs designed to foster the development of new in-state renewable electricity generation facilities, and to secure for the state the environmental, economic, and reliability benefits that operation of those facilities will provide.

(b) Any funds used for new in-state renewable electricity generation facilities pursuant to this section shall be expended in accordance with the report, subject to all of the following requirements:

(1) In order to cover the above market costs of eligible renewable energy resources as approved by the Public Utilities Commission and selected by retail sellers to fulfill their obligations under Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code, the commission shall award funds in the form of supplemental energy payments, subject to the following criteria:

(A) The commission may establish caps on supplemental energy payments. The caps shall be designed to provide for a viable energy market capable of achieving the goals of Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code. The commission may waive application of the caps to accommodate a facility if it is demonstrated to the satisfaction of the commission that operation of the facility would provide substantial economic and environmental benefits to end-use customers subject to the renewable energy public goods charge.

(B) Supplemental energy payments shall be awarded only to facilities that are eligible for funding under this section.

(C) Supplemental energy payments awarded to facilities selected by a retail seller or procurement entity pursuant to Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code shall be paid for no longer than 10 years, but shall, subject to the payment caps in subparagraph (A), be equal to the cumulative above-market costs relative to the applicable market price referent at the time of initial contracting, over the duration of the contract with the retail seller or procurement entity.

(D) The commission shall reduce or terminate supplemental energy payments for projects that fail either to commence and maintain operations consistent with the contractual obligations to an electrical corporation, or that fail to meet eligibility requirements.

(E) Funds shall be managed in an equitable manner in order for retail sellers to meet their obligation under Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code.

(F) A project selected by an electrical corporation may receive supplemental energy payments only if it results from a competitive solicitation that is found by the Public Utilities Commission to comply with the California Renewables Portfolio Standard Program under Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code, and the project has entered into an electricity purchase agreement resulting from that solicitation, that is approved by the Public Utilities Commission. A project selected for an electricity purchase agreement by another retail seller or procurement entity may receive supplemental energy payments only if the Public Utilities Commission determines that the selection of the project is consistent with the results of a least-cost and best-fit process, and the supplemental energy payments are reasonable in comparison to those paid under similar contracts with other retail sellers. The commission may not award supplemental energy payments to service load that is not subject to the renewable energy public goods charge.

(G) (i) Supplemental energy payments shall not be awarded for any purchases of renewable energy credits.

(ii) Supplemental energy payments shall not be awarded for electricity purchase agreements that have a duration of less than 10 years. The ineligibility of agreements of less than 10 years duration for supplemental energy payments does not constitute an insufficiency in supplemental energy payments pursuant to paragraph (4) or (5) of subdivision (b) of Section 399.15.

(2) (A) A facility that is located outside of California shall not be eligible for funding under this section unless it satisfies the requirements of this subdivision and the criteria of subparagraph (B) of paragraph (2) of subdivision (b) of Section 25741.

(B) No more than 10 percent of the funds available under this section shall be awarded to facilities located outside of California.

(3) Facilities that are eligible to receive funding pursuant to this section shall be registered in accordance with criteria developed by the commission and those facilities may not receive payments for any electricity produced that has any of the following characteristics:

(A) Is sold under an existing long-term contract with an existing in-state electrical corporation if the contract includes fixed energy or capacity payments, except for that electricity that satisfies subparagraph (C) of paragraph (1) of subdivision (c) of Section 399.6 of the Public Utilities Code.

(B) Is used onsite or is sold to customers in a manner that excludes competition transition charge payments, or is otherwise excluded from competition transition charge payments.

(C) Is a hydroelectric generation project that will require a new or increased appropriation of water under Part 2 (commencing with Section 1200) of Division 2 of the Water Code, or any other provision authorizing an appropriation of water.

(D) Is a solid waste conversion facility, unless the facility meets the criteria established in paragraph (3) of subdivision (b) of Section 25741 and the facility certifies that any local agency sending solid waste to the facility is in compliance with Division 30 (commencing with Section 40000), has reduced, recycled, or composted solid waste to the maximum extent feasible, and shall have been found by the California Integrated Waste Management Board to have diverted at least 30 percent of all solid waste through source reduction, recycling, and composting.

(4) Eligibility to compete for funds or to receive funds shall be contingent upon having to sell the electricity generated by the renewable electricity generation facility to customers subject to the renewable energy public goods charge.

(5) The commission may require applicants competing for funding to post a forfeitable bid bond or other financial guaranty as an assurance of the applicant's intent to move forward expeditiously with the project proposed. The amount of any bid bond or financial guaranty may not exceed 10 percent of the total amount of the funding requested by the applicant.

(6) In awarding funding, the commission may provide preference to projects that provide tangible demonstrable benefits to communities with a plurality of minority or low-income populations.

(c) Repowered existing facilities shall be eligible for funding under this subdivision if the capital investment to repower the existing facility equals at least 80 percent of the value of the repowered facility.

(d) Facilities engaging in the direct combustion of municipal solid waste or tires are not eligible for funding under this subdivision.

(e) Production incentives awarded under this subdivision prior to January 1, 2002, shall commence on the date that a project begins electricity production, provided that the project was operational prior to January 1, 2002, unless the commission finds that the project will not be operational prior to January 1, 2002, due to circumstances beyond the control of the developer. Upon making a finding that the project will not be operational due to circumstances beyond the control of the developer, the commission shall pay production incentives over a five-year period, commencing on the date of operation, provided that the date that a project begins electricity production may not extend beyond January 1, 2007.

(f) Facilities generating electricity from biomass energy shall be considered an in-state renewable electricity generation facility to the extent that they report to the commission the types and quantities of biomass fuels used and certify to the satisfaction of the commission that fuel utilization is limited to the following:

(1) Agricultural crops and agricultural wastes and residues.

(2) Solid waste materials such as waste pallets, crates, dunnage, manufacturing, and construction wood wastes, landscape or right-of-way tree trimmings, mill residues that are directly the result of the milling of lumber, and rangeland maintenance residues.

(3) Wood and wood wastes that meet all of the following requirements:

(A) Have been harvested pursuant to an approved timber harvest plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973 (Chapter 8 (commencing with Section 4511) of Part 2 of Division 4).

(B) Have been harvested for the purpose of forest fire fuel reduction or forest stand improvement.

(C) Do not transport or cause the transportation of species known to harbor insect or disease nests outside zones of infestation or current quarantine zones, as identified by the Department of Food and Agriculture or the Department of Forestry and Fire Protection, unless approved by the Department of Food and Agriculture and the Department of Forestry and Fire Protection.

SEC. 7. Section 25744.5 is added to the Public Resources Code, to read:

25744.5. The commission shall allocate and use funding available for emerging renewable technologies pursuant to Section 25744 and Section 25751 to fund photovoltaic and solar thermal electric technologies in accordance with eligibility criteria and conditions established pursuant to Chapter 8.8 (commencing with Section 25780).

SEC. 8. Section 25745 of the Public Resources Code is repealed.

SEC. 9. Section 25746 of the Public Resources Code is amended to read:

25746. (a) One percent of the money collected pursuant to the renewable energy public goods charge shall be used in accordance with this chapter to promote renewable energy and disseminate information on renewable energy technologies, including emerging renewable technologies, and to help develop a consumer market for renewable energy and for small-scale emerging renewable energy technologies.

(b) If the commission provides funding for a regional accounting system to verify compliance with the renewable portfolio standard by retail sellers, pursuant to subdivision (b) of Section 399.13 of the Public Utilities Code, the commission shall recover all costs from user fees.

SEC. 10. Section 25749 of the Public Resources Code is repealed.

SEC. 11. Section 25751 of the Public Resources Code is amended to read:

25751. (a) The Renewable Resource Trust Fund is hereby created in the State Treasury.

(b) The following accounts are hereby established within the Renewable Resource Trust Fund:

(1) The Existing Renewable Resources Account.

(2) New Renewable Resources Account.

(3) Emerging Renewable Resources Account.

(4) Renewable Resources Consumer Education Account.

(c) The money in the fund may be expended, only upon appropriation by the Legislature in the annual Budget Act, for the following purposes:

(1) The administration of this article by the state.

(2) The state's expenditures associated with the accounting system established by the commission pursuant to subdivision (b) of Section 399.13 of the Public Utilities Code.

(d) That portion of revenues collected by electrical corporations for the benefit of in-state operation and development of existing and new and emerging renewable resource technologies, pursuant to Section 25740.5, shall be transmitted to the commission at least quarterly for deposit in the Renewable Resource Trust Fund pursuant to Section 399.6 of the Public Utilities Code. After setting aside in the fund money that may be needed for expenditures authorized by the annual Budget Act in accordance with subdivision (c), the Treasurer shall immediately deposit money received pursuant to this section into the accounts created pursuant to subdivision (b) in proportions designated by the commission for the current calendar year. Notwithstanding Section 13340 of the Government Code, the money in the fund and the accounts within the fund are hereby continuously appropriated to the commission without regard to fiscal year for the purposes enumerated in this chapter.

(e) Upon notification by the commission, the Controller shall pay all awards of the money in the accounts created pursuant to subdivision (b) for purposes enumerated in this chapter. The eligibility of each award shall be determined solely by the commission based on the procedures it adopts under this chapter. Based on the eligibility of each award, the commission shall also establish the need for a multiyear commitment to any particular award and so advise the Department of Finance. Eligible awards submitted by the commission to the Controller shall be accompanied by information specifying the account from which payment should be made and the amount of each payment; a summary description of how payment of the award furthers the purposes enumerated in this chapter; and an accounting of future costs associated with any award or group of awards known to the commission to represent a portion of a multiyear funding commitment.

(f) The commission may transfer funds between accounts for cashflow purposes, provided that the balance due each account is restored and the transfer does not adversely affect any of the accounts.

(g) The Department of Finance shall conduct an independent audit of the Renewable Resource Trust Fund and its related accounts annually, and provide an audit report to the Legislature not later than March 1 of each year for which this article is operative. The Department of Finance's report shall include information regarding revenues, payment of awards, reserves held for future commitments, unencumbered cash balances, and other matters that the Director of Finance determines may be of importance to the Legislature.

SEC. 12. Section 387 of the Public Utilities Code is amended to read:

387. (a) Each governing body of a local publicly owned electric utility, as defined in Section 9604, shall be responsible for implementing and enforcing a renewables portfolio standard that recognizes the intent of the Legislature to encourage renewable resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement.

(b) Each local publicly owned electric utility shall report, on an annual basis, to its customers and to the State Energy Resources Conservation and Development Commission, the following:

(1) Expenditures of public goods funds collected pursuant to Section 385 for eligible renewable energy resource development. Reports shall contain a description of programs, expenditures, and expected or actual results.

(2) The resource mix used to serve its customers by fuel type. Reports shall contain the contribution of each type of renewable energy resource with separate categories for those fuels that are eligible renewable energy resources as defined in Section 399.12, except that the electricity is delivered to the local publicly owned electric utility and not a retail seller. Electricity shall be reported as having been delivered to the local publicly owned electric utility from an eligible renewable energy resource when the electricity would qualify for compliance with the renewables portfolio standard if it were delivered to a retail seller.

(3) The utility's status in implementing a renewables portfolio standard pursuant to subdivision (a) and the utility's progress toward attaining the standard following implementation.

SEC. 13. Section 399.11 of the Public Utilities Code is amended to read:

399.11. The Legislature finds and declares all of the following:

(a) In order to attain a target of generating 20 percent of total retail sales of electricity in California from eligible renewable energy resources by December 31, 2010, and for the purposes of increasing the diversity, reliability, public health and environmental benefits of the energy mix, it is the intent of the Legislature that the commission and the State Energy Resources Conservation and Development Commission implement the California Renewables Portfolio Standard Program described in this article.

(b) Increasing California's reliance on eligible renewable energy resources may promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels.

(c) The development of eligible renewable energy resources and the delivery of the electricity generated by those resources to customers in California may ameliorate air quality problems throughout the state and improve public health by reducing the burning of fossil fuels and the associated environmental impacts and by reducing in-state fossil fuel consumption.

(d) The California Renewables Portfolio Standard Program is intended to complement the Renewable Energy Resources Program administered by the State Energy Resources Conservation and Development Commission and established pursuant to Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code.

(e) New and modified electric transmission facilities may be necessary to facilitate the state achieving its renewables portfolio standard targets.

SEC. 14. Section 399.12 of the Public Utilities Code is amended to read:

399.12. For purposes of this article, the following terms have the following meanings:

(a) “Delivered” and “delivery” have the same meaning as provided in subdivision (a) of Section 25741 of the Public Resources Code.

(b) “Eligible renewable energy resource” means an electric generating facility that meets the definition of “in-state renewable electricity generation facility” in Section 25741 of the Public Resources Code, subject to the following limitations:

(1) (A) An existing small hydroelectric generation facility of 30 megawatts or less shall be eligible only if a retail seller owned or procured the electricity from the facility as of December 31, 2005. A new hydroelectric facility is not an eligible renewable energy resource if it will require a new or increased appropriation or diversion of water from a watercourse.

(B) Notwithstanding subparagraph (A), an existing conduit hydroelectric facility, as defined by Section 823a of Title 16 of the United States Code, of 30 megawatts or less, shall be an eligible renewable energy resource. A new conduit hydroelectric facility, as defined by Section 823a of Title 16 of the United States Code, of 30 megawatts or less, shall be an eligible renewable energy resource so long as it does not require a new or increased appropriation or diversion of water from a watercourse.

(3) A facility engaged in the combustion of municipal solid waste shall not be considered an eligible renewable resource unless it is located in Stanislaus County and was operational prior to September 26, 1996.

(c) “Energy Commission” means the State Energy Resources Conservation and Development Commission.

(d) “Local publicly owned electric utility” has the same meaning as provided in subdivision (d) of Section 9604.

(e) “Procure” means that a retail seller receives delivered electricity generated by an eligible renewable energy resource that it owns or for which it has entered into an electricity purchase agreement. Nothing in this article is intended to imply that the purchase of electricity from third parties in a wholesale transaction is the preferred method of fulfilling a retail seller’s obligation to comply with this article.

(f) “Renewables portfolio standard” means the specified percentage of electricity generated by eligible renewable energy resources that a retail seller is required to procure pursuant to this article.

(g) (1) “Renewable energy credit” means a certificate of proof, issued through the accounting system established by the Energy Commission pursuant to Section 399.13, that one unit of electricity was generated and delivered by an eligible renewable energy resource.

(2) “Renewable energy credit” includes all renewable and environmental attributes associated with the production of electricity from the eligible renewable energy resource, except for an emissions reduction credit issued pursuant to Section 40709 of the Health and Safety Code and any credits or payments associated with the reduction of solid waste and treatment benefits created by the utilization of biomass or biogas fuels.

(3) No electricity generated by an eligible renewable energy resource attributable to the use of nonrenewable fuels, beyond a de minimus quantity, as determined by the Energy Commission, shall result in the creation of a renewable energy credit.

(h) "Retail seller" means an entity engaged in the retail sale of electricity to end-use customers located within the state, including any of the following:

(1) An electrical corporation, as defined in Section 218.

(2) A community choice aggregator. The commission shall institute a rulemaking to determine the manner in which a community choice aggregator will participate in the renewables portfolio standard program subject to the same terms and conditions applicable to an electrical corporation.

(3) An electric service provider, as defined in Section 218.3, for all sales of electricity to customers beginning January 1, 2006. The commission shall institute a rulemaking to determine the manner in which electric service providers will participate in the renewables portfolio standard program. The electric service provider shall be subject to the same terms and conditions applicable to an electrical corporation pursuant to this article. Nothing in this paragraph shall impair a contract entered into between an electric service provider and a retail customer prior to the suspension of direct access by the commission pursuant to Section 80110 of the Water Code.

(4) "Retail seller" does not include any of the following:

(A) A corporation or person employing cogeneration technology or producing electricity consistent with subdivision (b) of Section 218.

(B) The Department of Water Resources acting in its capacity pursuant to Division 27 (commencing with Section 80000) of the Water Code.

(C) A local publicly owned electric utility.

SEC. 15. Section 399.13 of the Public Utilities Code is amended to read:

399.13. The Energy Commission shall do all of the following:

(a) Certify eligible renewable energy resources that it determines meet the criteria described in subdivision (b) of Section 399.12.

(b) Design and implement an accounting system to verify compliance with the renewables portfolio standard by retail sellers, to ensure that electricity generated by an eligible renewable energy resource is counted only once for the purpose of meeting the renewables portfolio standard of this state or any other state, to certify renewable energy credits produced by eligible renewable energy resources, and to verify retail product claims in this state or any other state. In establishing the guidelines governing this accounting system, the Energy Commission shall collect data from electricity market participants that it deems necessary to verify compliance of retail sellers, in accordance with the requirements of this article and the California Public Records Act (Chapter 3.5 (commencing with Section 6250) of Division 7 of Title 1 of the Government Code). In seeking data from electrical corporations, the Energy Commission shall request data from the commission. The commission shall collect data from electrical corporations and remit the data to the Energy Commission within 90 days of the request.

(c) Establish a system for tracking and verifying renewable energy credits that, through the use of independently audited data, verifies the generation and delivery of electricity associated with each renewable energy credit and protects against multiple counting of the same renewable energy credit. The Energy Commission shall consult with other western states and with the Western Electricity Coordinating Council in the development of this system.

(d) Certify, for purposes of compliance with the renewable portfolio standard requirements by a retail seller, the eligibility of renewable energy credits associated with deliveries of electricity by an eligible renewable energy resource to a local publicly owned electric utility, if the Energy Commission determines that the following conditions have been satisfied:

(1) The local publicly owned electric utility that is procuring the electricity is in compliance with the requirements of Section 387.

(2) The local publicly owned electric utility has established an annual renewables portfolio standard target comparable to those applicable to an electrical corporation, is procuring sufficient eligible renewable energy resources to satisfy the targets, and will not fail to satisfy the targets in the event that the renewable energy credit is sold to another retail seller.

(e) Allocate and award supplemental energy payments pursuant to Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code, to eligible renewable energy resources to cover above-market costs of renewable energy. A project selected by an electrical corporation may receive supplemental energy payments only if it results from a competitive solicitation that is found by the commission to comply with the California Renewables Portfolio Standard Program under this article and the project has entered into an electricity purchase agreement resulting from that solicitation that is approved by the commission. A project selected for an electricity purchase agreement by another retail seller may receive supplemental energy payments only if the retail seller demonstrates to the commission that the selection of the project is consistent with the results of a least-cost and best-fit process, and that the supplemental energy payments are reasonable in comparison to those paid under similar contracts with other retail sellers.

SEC. 16. Section 399.14 of the Public Utilities Code is amended to read:

399.14. (a) (1) The commission shall direct each electrical corporation to prepare a renewable energy procurement plan that includes the matter in paragraph (3), to satisfy its obligations under the renewables portfolio standard. To the extent feasible, this procurement plan shall be proposed, reviewed, and adopted by the commission as part of, and pursuant to, a general procurement plan process. The commission shall require each electrical corporation to review and update its renewable energy procurement plan as it determines to be necessary.

(2) The commission shall adopt, by rulemaking, all of the following:

(A) A process for determining market prices pursuant to subdivision (c) of Section 399.15. The commission shall make specific determinations of market prices after the closing date of a competitive solicitation conducted by an electrical corporation for eligible renewable energy resources.

(B) A process that provides criteria for the rank ordering and selection of least-cost and best-fit eligible renewable energy resources to comply with the annual California Renewables Portfolio Standard Program obligations on a total cost basis. This process shall consider estimates of indirect costs associated with needed transmission investments and ongoing utility expenses resulting from integrating and operating eligible renewable energy resources.

(C) (i) Flexible rules for compliance, including rules permitting retail sellers to apply excess procurement in one year to subsequent years or inadequate procurement in one year to no more than the following three years. The flexible rules for compliance shall apply to all years, including years before and after a retail seller procures at least 20 percent of total retail sales of electricity from eligible renewable energy resources.

(ii) The flexible rules for compliance shall address situations where, as a result of insufficient transmission, a retail seller is unable to procure eligible renewable energy resources sufficient to satisfy the requirements of this article. Any rules addressing insufficient transmission shall require a finding by the commission that the retail seller has undertaken all reasonable efforts to do all of the following:

(I) Utilize flexible delivery points.

(II) Ensure the availability of any needed transmission capacity.

(III) If the retail seller is an electric corporation, to construct needed transmission facilities.

(IV) Nothing in this subparagraph shall be construed to revise any portion of Section 454.5.

(D) Standard terms and conditions to be used by all electrical corporations in contracting for eligible renewable energy resources, including performance requirements for renewable generators. A contract for the purchase of electricity generated by an eligible renewable energy resource shall, at a minimum, include the renewable energy credits associated with all electricity generation specified under the contract. The standard terms and conditions shall include the requirement that, no later than six months after the commission's approval of an electricity purchase agreement entered into pursuant to this article, the following information about the agreement shall be disclosed by the commission: party names, resource type, project location, and project capacity.

(3) Consistent with the goal of procuring the least-cost and best-fit eligible renewable energy resources, the renewable energy procurement plan submitted by an electrical corporation shall include all of the following:

(A) An assessment of annual or multiyear portfolio supplies and demand to determine the optimal mix of eligible renewable energy resources with deliverability characteristics that may include peaking, dispatchable, baseload, firm, and as-available capacity.

(B) Provisions for employing available compliance flexibility mechanisms established by the commission.

(C) A bid solicitation setting forth the need for eligible renewable energy resources of each deliverability characteristic, required online dates, and locational preferences, if any.

(4) In soliciting and procuring eligible renewable energy resources, each electrical corporation shall offer contracts of no less than 10 years in duration, unless the commission approves of a contract of shorter duration.

(5) In soliciting and procuring eligible renewable energy resources, each electrical corporation may give preference to projects that provide tangible demonstrable benefits to communities with a plurality of minority or low-income populations.

(b) The commission may authorize a retail seller to enter into a contract of less than 10 years' duration with an eligible renewable energy resource, subject to the following conditions:

(1) No supplemental energy payments shall be awarded for a contract of less than 10 years' duration. The ineligibility of contracts of less than 10 years' duration for supplemental energy payments pursuant to this paragraph does not constitute an insufficiency in supplemental energy payments pursuant to paragraph (4) or (5) of subdivision (b) of Section 399.15.

(2) The commission has established, for each retail seller, minimum quantities of eligible renewable energy resources to be procured either through contracts of at least 10 years' duration or from new facilities commencing commercial operations on or after January 1, 2005.

(c) The commission shall review and accept, modify, or reject each electrical corporation's renewable energy procurement plan prior to the commencement of renewable procurement pursuant to this article by an electrical corporation.

(d) The commission shall review the results of an eligible renewable energy resources solicitation submitted for approval by an electrical corporation and accept or reject proposed contracts with eligible renewable energy resources based on consistency with the approved renewable energy procurement plan. If the commission determines that the bid prices are elevated due to a lack of effective competition amongst the bidders, the commission shall direct the electrical corporation to renegotiate the contracts or conduct a new solicitation.

(e) If an electrical corporation fails to comply with a commission order adopting a renewable energy procurement plan, the commission shall exercise its authority pursuant to Section 2113 to require compliance. The commission shall enforce comparable penalties on any other retail seller that fails to meet annual procurement targets established pursuant to Section 399.15.

(f) (1) The commission may authorize a procurement entity to enter into contracts on behalf of customers of a retail seller for deliveries of eligible renewable energy resources to satisfy annual renewables portfolio standard obligations. The commission may not require any person or corporation to act as a procurement entity or require any party to purchase eligible renewable energy resources from a procurement entity.

(2) Subject to review and approval by the commission, the procurement entity shall be permitted to recover reasonable administrative and procurement costs through the retail rates of end-use customers that are served by the procurement entity and are directly benefiting from the procurement of eligible renewable energy resources.

(3) A project selected for a long-term electricity purchase contract of more than 10 years' duration by a procurement entity through a competitive solicitation, and approved by the commission, may receive supplemental energy payments from the Energy Commission if the transaction satisfies the requirements of subdivision (b) of Section 25743 of the Public Resources Code.

(g) Procurement and administrative costs associated with long-term contracts entered into by an electrical corporation for eligible renewable energy resources pursuant to this article, at or below the market price determined by the commission pursuant to subdivision (c) of Section 399.15, shall be deemed reasonable per se, and shall be recoverable in rates.

(h) Construction, alteration, demolition, installation, and repair work on an eligible renewable energy resource that receives production incentives or supplemental energy payments pursuant to Sections 25742 and 25743 of the Public Resources Code, including work performed to qualify, receive, or maintain production incentives or supplemental energy payments is "public works" for the purposes of Chapter 1 (commencing with Section 1720) of Part 7 of Division 2 of the Labor Code.

SEC. 17. Section 399.15 of the Public Utilities Code is amended to read:

399.15. (a) In order to fulfill unmet long-term resource needs, the commission shall establish a renewables portfolio standard requiring all electrical corporations to procure a minimum quantity of electricity generated by eligible renewable energy resources as a specified percentage of total kilowatthours sold to their retail end-use customers each calendar year, if sufficient funds are made available pursuant to Section 399.6 and Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code, to cover the above-market costs of eligible renewable energy resources.

(b) The commission shall implement annual procurement targets for each retail seller as follows:

(1) Each retail seller shall, pursuant to subdivision (a), increase its total procurement of eligible renewable energy resources by at least an additional 1 percent of retail sales per year so that 20 percent of its retail sales are procured from eligible renewable energy resources no later than December 31, 2010. A retail seller with 20 percent of retail sales procured from eligible renewable energy resources in any year shall not be required

to increase its procurement of renewable energy resources in the following year.

(2) For purposes of setting annual procurement targets, the commission shall establish an initial baseline for each retail seller based on the actual percentage of retail sales procured from eligible renewable energy resources in 2001, and to the extent applicable, adjusted going forward pursuant to Section 399.12.

(3) Only for purposes of establishing these targets, the commission shall include all electricity sold to retail customers by the Department of Water Resources pursuant to Section 80100 of the Water Code in the calculation of retail sales by an electrical corporation.

(4) In the event that a retail seller fails to procure sufficient eligible renewable energy resources in a given year to meet any annual target established pursuant to this subdivision, the retail seller shall procure additional eligible renewable energy resources in subsequent years to compensate for the shortfall if sufficient funds are made available pursuant to Section 399.6 and Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code, to cover any above-market costs of eligible renewable energy resources.

(5) If supplemental energy payments from the Energy Commission, in combination with the market prices approved by the commission, are insufficient to cover any above-market costs of electricity procured from eligible renewable energy resources through an electricity purchase agreement of at least 10 years' duration, the commission shall allow a retail seller to limit its annual procurement obligation to the quantity of eligible renewable energy resources that can be procured with available supplemental energy payments. A retail seller shall not be required to enter into long-term contracts with operators of eligible renewable energy resources that exceed the market prices established pursuant to subdivision (c).

(c) The commission shall establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with eligible renewable energy resources, in consideration of the following:

(1) The long-term market price of electricity for fixed price contracts, determined pursuant to an electrical corporation's general procurement activities as authorized by the commission.

(2) The long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities.

(3) The value of different products including baseload, peaking, and as-available electricity.

(d) The Energy Commission shall provide supplemental energy payments from funds in the New Renewable Resources Account of the Renewable Resource Trust Fund to eligible renewable energy resources pursuant to Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code, consistent with this article, for any above-market costs. Indirect costs associated with the purchase of eligible renewable energy resources by an electrical corporation, including imbalance energy charges, sale of excess energy, decreased generation from existing resources, or transmission upgrades, shall not be eligible for supplemental energy payments, but are recoverable in rates, as authorized by the commission. The Energy Commission shall not award supplemental energy payments to service load that is not subject to the renewable energy public goods charge.

(e) The establishment of a renewables portfolio standard shall not constitute implementation by the commission of the federal Public Utility Regulatory Policies Act of 1978 (Public Law 95-617).

(f) The commission shall consult with the Energy Commission in calculating market prices under subdivision (c) and establishing other renewables portfolio standard policies.

SEC. 18. Section 399.16 of the Public Utilities Code is repealed.

SEC. 19. Section 399.16 is added to the Public Utilities Code, to read:

399.16. (a) The commission, by rule, may authorize the use of renewable energy credits to satisfy the requirements of the renewables portfolio standard established pursuant to this article, subject to the following conditions:

(1) Prior to authorizing any renewable energy credit to be used toward satisfying annual procurement targets, the commission and the Energy Commission shall conclude that the tracking system established pursuant to subdivision (c) of Section 399.13, is operational, is capable of independently verifying the electricity generated by an eligible renewable energy resource and delivered to the retail seller, and can ensure that renewable energy credits shall not be double counted by any seller of electricity within the service territory of the Western Electricity Coordinating Council (WECC).

(2) A renewable energy credit shall be counted only once for compliance with the renewables portfolio standard of this state or any other state, or for verifying retail product claims in this state or any other state.

(3) The electricity is delivered to a retail seller, the Independent System Operator, or a local publicly owned electric utility.

(4) All revenues received by an electrical corporation for the sale of a renewable energy credit shall be credited to the benefit of ratepayers.

(5) No renewable energy credits shall be created for electricity generated pursuant to any electricity purchase contract with a retail seller or a local publicly owned electric utility executed before January 1, 2005, unless the contract contains explicit terms and conditions specifying the ownership or disposition of those credits. Deliveries under those contracts shall be tracked through the accounting system described in subdivision (b) of Section 399.13 and included in the baseline quantity of eligible renewable energy resources of the purchasing retail seller pursuant to Section 399.15.

(6) No renewable energy credits shall be created for electricity generated under any electricity purchase contract executed after January 1,

2005, pursuant to the federal Public Utility Regulatory Policies Act of 1978 (16 U.S.C. Sec. 2601 et seq.). Deliveries under the electricity purchase contracts shall be tracked through the accounting system described in subdivision (b) of Section 399.12 and count towards the renewables portfolio standard obligations of the purchasing retail seller.

(7) The commission may limit the quantity of renewable energy credits that may be procured unbundled from electricity generation by any retail seller, to meet the requirements of this article.

(8) No retail seller shall be obligated to procure renewable energy credits to satisfy the requirements of this article in the event that supplemental energy payments, in combination with the market prices approved by the commission, are insufficient to cover the above-market costs of long-term contracts, of more than 10 years' duration, with eligible renewable energy resources.

(9) Any additional condition that the commission determines is reasonable.

(b) The commission shall allow an electrical corporation to recover the reasonable costs of purchasing renewable energy credits in rates.

SEC. 20. Article 9 (commencing with Section 635) is added to Chapter 3 of Part 1 of Division 1 of the Public Utilities Code, to read:

Article 9. Long-Term Plans and Procurement Plans

635. In a long-term plan adopted by an electrical corporation or in a procurement plan implemented by a local publicly owned electric utility, the electrical corporation or local publicly owned electric utility shall adopt a strategy applicable both to newly constructed or repowered generation owned and procured by the electrical corporation or local publicly owned electric utility to achieve efficiency in the use of fossil fuels and to address carbon emissions.

SEC. 21. Section 2854 is added to Chapter 9 of Part 2 of Division 1 of the Public Utilities Code, to read:

2854. (a) Notwithstanding Section 7550.5 of the Government Code, on or before January 1, 2008, the commission shall report to the Legislature on the feasibility, desirability, and design of performance-based incentives for solar energy systems of less than 30 kilowatt.

(b) This section shall remain in effect only until January 1, 2009, and as of that date is repealed, unless a later enacted statute, that is enacted before January 1, 2009, deletes or extends that date.

SEC. 22. By June 30, 2007, the Public Utilities Commission, in consultation with the State Energy Resources Conservation and Development Commission, shall review the impact of allowing supplemental energy payments to be applied toward contracts for the procurement of eligible renewable energy resources that are of a duration of less than 10 years, and to report to the Legislature with the results of the review, including both of the following:

(a) The impact that higher priced short-term contracts may have on the allocation of supplemental energy payments.

(b) Recommended methods to fairly allocate supplemental energy payments for the above-market costs of short-term contracts that ensure that no more supplemental energy payments are paid for those contracts than would have been allocated for an equivalent long-term contract.

SEC. 23. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution for certain costs that may be incurred by a local agency or school district because, in that regard, this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

However, if the Commission on State Mandates determines that this act contains other costs mandated by the state, reimbursement to local agencies and school districts for those costs shall be made pursuant to Part 7 (commencing with Section 17500) of Division 4 of Title 2 of the Government Code.

O

Senate Bill No. 380

CHAPTER 544

An act to amend Section 399.20 of the Public Utilities Code, relating to energy.

[Approved by Governor September 28, 2008. Filed with Secretary of State September 28, 2008.]

LEGISLATIVE COUNSEL'S DIGEST

SB 380, Kehoe. Renewable energy resources.

Under existing law, the Public Utilities Commission has regulatory authority over public utilities, including electrical corporations, as defined. Existing law requires every electrical corporation to file with the commission a standard tariff for electricity generated by an electric generation facility, as defined, that is an eligible renewable energy resource with an effective capacity of not more than one megawatt, is located on property owned or under the control of a public water or wastewater agency, is sized to offset part or all of the electricity demand of the public water or wastewater agency, and meets other deliverability and interconnection requirements. The tariff is required to provide for payment for every kilowatthour of electricity generated by the electric generation facility at a market price determined by the commission pursuant to a specified law, for a period of 10, 15, or 20 years. Existing law requires the electrical corporation to make this tariff available to public water or wastewater agencies that own and operate an electric generation facility within the service territory of the electrical corporation, upon request, on a first-come-first-served basis, until the combined statewide cumulative rated generating capacity of those electric generation facilities equals 250 megawatts, or the electrical corporation meets its proportionate share of the 250 megawatt limit based upon the ratio of its peak demand to total statewide peak demand of all electrical corporations. Existing law authorizes the commission to extend availability of the tariff to electric generation facilities not larger than 1.5 megawatts that otherwise comply with the above-described requirements.

This bill would instead require every electrical corporation to file with the commission a standard tariff for electricity generated by an electric generation facility with an effective capacity of not more than 1.5 megawatts, that is located on property owned or under the control of a customer, and that meets other deliverability and interconnection requirements. The bill would require the electrical corporation to make this tariff available to customers that own and operate an electric generation facility within the service territory of the electrical corporation, upon request, on a first-come-first-served basis, until the combined statewide cumulative rated generating capacity of those electric generation facilities equals 500 megawatts, or the electrical corporation meets its proportionate share of the 500 megawatt limit based upon the ratio of its peak demand to total statewide peak demand of all electrical corporations. The bill would authorize the commission to modify or adjust the above-described requirements for any electrical corporation with less than 100,000 service connections, as individual circumstances merit.

Under existing law, a violation of the Public Utilities Act or an order or direction of the commission is a crime. Because this bill would require an order or other action of the commission to implement its provisions and a violation of that order or action would be a crime, the bill would impose a state-mandated local program by creating a new crime.

The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

This bill would provide that its provisions would not become operative if SB 1714 of the 2007–08 Regular Session is enacted on or before January 1, 2009, amending Section 399.20 of the Public Utilities Code.

The people of the State of California do enact as follows:

SECTION 1. Section 399.20 of the Public Utilities Code is amended to read:

399.20. (a) It is the policy of this state and the intent of the Legislature to encourage energy production from renewable energy resources.

(b) As used in this section, “electric generation facility” means an electric generation facility, owned and operated by a retail customer of an electrical corporation, and that meets all of the following criteria:

(1) Has an effective capacity of not more than one and one-half megawatts and is located on property owned or under the control of the customer.

(2) Is interconnected and operates in parallel with the electric transmission and distribution grid.

(3) Is strategically located and interconnected to the electric transmission system in a manner that optimizes the deliverability of electricity generated at the facility to load centers.

(4) Is an eligible renewable energy resource, as defined in Section 399.12.

(c) Every electrical corporation shall file with the commission a standard tariff for electricity generated by an electric generation facility.

(d) The tariff shall provide for payment for every kilowatthour of electricity generated by an electric generation facility at the market price as determined by the commission pursuant to Section 399.15 for a period of 10, 15, or 20 years, as authorized by the commission.

(e) Every electrical corporation shall make this tariff available to customers that own and operate an electric generation facility within the service territory of the electrical corporation, upon request, on a first-come-first-served basis, until the combined statewide cumulative rated generating capacity of those electric generation facilities equals 500 megawatts. An electrical corporation may make the terms of the tariff available to customers in the form of a standard contract subject to commission approval. Each electrical corporation shall only be required to offer service or contracts under this section until that electrical corporation meets its proportionate share of the 500 megawatts based on the ratio of its peak demand to the total statewide peak demand of all electrical corporations.

(f) Every kilowatthour of electricity generated by the electric generation facility shall count toward the electrical corporation's renewables portfolio standard annual procurement targets for purposes of paragraph (1) of subdivision (b) of Section 399.15.

(g) The physical generating capacity of an electric generation facility shall count toward the electrical corporation's resource adequacy requirement for purposes of Section 380.

(h) The commission may modify or adjust the requirements of this section for any electrical corporation with less than 100,000 service connections, as individual circumstances merit.

SEC. 2. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

SEC. 3. This bill shall not become operative if Senate Bill 1714 of the 2007–08 Regular Session is enacted on or before January 1, 2009, and amends Section 399.20 of the Public Utilities Code.

O

Office of the Governor ARNOLD SCHWARZENEGGER THE PEOPLE'S GOVERNOR

EXECUTIVE ORDER EXECUTIVE ORDER S-3-05

06/01/2005

WHEREAS, California is particularly vulnerable to the impacts of climate change; and

WHEREAS, increased temperatures threaten to greatly reduce the Sierra snowpack, one of the State's primary sources of water; and

WHEREAS, increased temperatures also threaten to further exacerbate California's air quality problems and adversely impact human health by increasing heat stress and related deaths, the incidence of infectious disease, and the risk of asthma, respiratory and other health problems; and

WHEREAS, rising sea levels threaten California's 1,100 miles of valuable coastal real estate and natural habitats; and

WHEREAS, the combined effects of an increase in temperatures and diminished water supply and quality threaten to alter micro-climates within the state, affect the abundance and distribution of pests and pathogens, and result in variations in crop quality and yield; and

WHEREAS, mitigation efforts will be necessary to reduce greenhouse gas emissions and adaptation efforts will be necessary to prepare Californians for the consequences of global warming; and

WHEREAS, California has taken a leadership role in reducing greenhouse gas emissions by: implementing the California Air Resources Board motor vehicle greenhouse gas emission reduction regulations; implementing the Renewable Portfolio Standard that the Governor accelerated; and implementing the most effective building and appliance efficiency standards in the world; and

WHEREAS, California-based companies and companies with significant activities in California have taken leadership roles by reducing greenhouse gas (GHG) emissions, including carbon dioxide, methane, nitrous oxide and hydrofluorocarbons, related to their operations and developing products that will reduce GHG emissions; and

WHEREAS, companies that have reduced GHG emissions by 25 percent to 70 percent have lowered operating costs and increased profits by billions of dollars; and

WHEREAS, technologies that reduce greenhouse gas emissions are increasingly in demand in the worldwide marketplace, and California companies investing in these technologies are well-positioned to profit from this demand, thereby boosting California's economy, creating more jobs and providing increased tax revenue; and

WHEREAS, many of the technologies that reduce greenhouse gas emissions also generate operating cost savings to consumers who spend a portion of the savings across a variety of sectors of the economy; this increased spending creates jobs and an overall benefit to the statewide economy.

NOW, THEREFORE, I, ARNOLD SCHWARZENEGGER, Governor of the State of California, by virtue of the power invested in me by the Constitution and statutes of the State of California, do hereby order effective immediately:

1. That the following greenhouse gas emission reduction targets are hereby established for California: by 2010, reduce GHG emissions to 2000 levels; by 2020, reduce GHG emissions to 1990 levels; by 2050, reduce GHG

emissions to 80 percent below 1990 levels; and

2. That the Secretary of the California Environmental Protection Agency ("Secretary") shall coordinate oversight of the efforts made to meet the targets with: the Secretary of the Business, Transportation and Housing Agency, Secretary of the Department of Food and Agriculture, Secretary of the Resources Agency, Chairperson of the Air Resources Board, Chairperson of the Energy Commission, and the President of the Public Utilities Commission; and

3. That the Secretary shall report to the Governor and the State Legislature by January 2006 and biannually thereafter on progress made toward meeting the greenhouse gas emission targets established herein; and

4. That the Secretary shall also report to the Governor and the State Legislature by January 2006 and biannually thereafter on the impacts to California of global warming, including impacts to water supply, public health, agriculture, the coastline, and forestry, and shall prepare and report on mitigation and adaptation plans to combat these impacts; and

5. That as soon as hereafter possible, this Order shall be filed with the Office of the Secretary of State and that widespread publicity and notice be given to this Order.

IN WITNESS WHEREOF I have here unto set my hand and caused the Great Seal of the State of California to be affixed this the first day of June 2005.

/s/ Arnold Schwarzenegger

Governor of California

California Environmental Quality Act

Title 14. California Code of Regulations
Chapter 3. Guidelines for Implementation of the California Environmental Quality Act
Article 19. Categorical Exemptions

Section 15328. Small Hydroelectric Projects at Existing Facilities

Class 28 consists of the installation of hydroelectric generating facilities in connection with existing dams, canals, and pipelines where:

(a) The capacity of the generating facilities is 5 megawatts or less;

(b) Operation of the generating facilities will not change the flow regime in the affected stream, canal, or pipeline including but not limited to:

(1) Rate and volume of flow;
(2) Temperature;
(3) Amounts of dissolved oxygen to a degree that could adversely affect aquatic life; and
(4) Timing of release.

(c) New power lines to connect the generating facilities to existing power lines will not exceed one mile in length if located on a new right of way and will not be located adjacent to a wild or scenic river;

(d) Repair or reconstruction of the diversion structure will not raise the normal maximum surface elevation of the impoundment;

(e) There will be no significant upstream or downstream passage of fish affected by the project;

(f) The discharge from the power house will not be located more than 300 feet from the toe of the diversion structure;

(g) The project will not cause violations of applicable state or federal water quality standards;

(h) The project will not entail any construction on or alteration of a site included in or eligible for inclusion in the National Register of Historic Places; and

(i) Construction will not occur in the vicinity of any endangered, rare, or threatened species.

Note: Authority cited: Section 21083, Public Resources Code; Reference: Section 21084, Public Resources Code.

Subpart K—Exemption of Small Hydroelectric Power Projects of 5 Megawatts or Less

§ 4.101 Applicability.

This subpart provides procedures for exemption on a case-specific basis from all or part of Part I of the Federal Power Act (Act), including licensing, for small hydroelectric power projects as defined in §4.30(b)(29).

(Energy Security Act of 1980, Pub. L. 96–294, 94 Stat. 611; Federal Power Act, as amended (16 U.S.C. 792–828c); Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2601–2645); and the Department of Energy Organization Act (42 U.S.C. 7101–7352); E.O. 12009, 3 CFR 142 (1978))

[Order 202, 47 FR 4243, Jan. 29, 1982, as amended by Order 413, 50 FR 11687, Mar. 25, 1985; Order 482, 52 FR 39630, Oct. 23, 1987; Order 2002, 68 FR 51121, Aug. 25, 2003]

§ 4.102 Surrender of exemption.

(a) To voluntarily surrender its exemption, a holder of an exemption for a small hydroelectric power project must file a petition with the Commission.

(b) (1) If construction has begun, prior to filing a petition with the Commission, the exemption holder must consult with the fish and wildlife agencies in accordance with §4.38, substituting for the information required under §4.38(b)(1) information appropriate to the disposition and restoration of the project works and lands. The petition must set forth the exemption holder's plans with respect to disposition and restoration of the project works and lands.

(2) If construction has begun, public notice of the petition will be given, and, at least 30 days thereafter, the Commission will act upon the petition. New applications involving the site may be filed on the next business day.

(c) If no construction had begun, unless the Commission issues an order to the contrary, the surrender will take effect at the close of the thirtieth day after the Commission issues a public notice of receipt of the petition. New applications involving the site may be filed on the next business day.

(d) Exemptions may be surrendered only upon fulfillment by the exemption holder of such obligations under the exemption as the Commission may prescribe and, if construction has begun, upon such conditions with respect to the disposition of such project works and restoration of project lands as may be determined by the Commission and the Federal and state fish and wildlife agencies.

(e) Where occupancy of United States lands or reservations has been permitted by a Federal agency having supervision over such lands, the exemption holder must concurrently notify that agency of the petition to surrender and of the steps that will be taken to restore the affected U.S. lands or reservations.

[Order 413, 50 FR 11688, Mar. 25, 1985]

§ 4.103 General provisions for case-specific exemption.

(a) *Exemptible projects.* Subject to the provisions in paragraph (b) of this section, §4.31(c), and §§4.105 and 4.106, the Commission may exempt on a case-specific basis any small hydroelectric power project from all or part of Part I of the Act, including licensing requirements. Any applications for exemption for a project shall conform to the requirements of §§4.107 or 4.108, as applicable.

(b) *Limitation for licensed water power project.* The Commission will not accept for filing an application for exemption from licensing for any project that is only part of a licensed water power project.
(c) *Waiver.* In applying for case-specific exemption from licensing, a qualified exemption applicant may petition under §385.207 of this chapter for waiver of any specific provision of §§4.102 through 4.107. The Commission will grant a waiver only if consistent with section 408 of the Energy Security Act of 1980.

[Order 413, 50 FR 11688, Mar. 25, 1985, as amended by Order 503, 53 FR 36568, Sept. 21, 1988]

§ 4.104 Amendment of exemption.

(a) An exemption holder must construct and operate its project as described in the exemption application approved by the Commission or its delegate.

(b) If an exemption holder desires to change the design, location, method of construction or operation of its project, it must first notify the appropriate Federal and state fish and wildlife agencies and inform them in writing of the changes it intends to implement. If these agencies determine that the changes would not cause the project to violate the terms and conditions imposed by the agencies, and if the changes would not materially alter the design, location, method of construction or operation of the project, the exemption holder may implement the changes. If any of these agencies determines that the changes would cause the project to violate the terms and conditions imposed by that agency, or if the changes would materially alter the design, location, method of construction or the operation of the project works, the exemption holder may not implement the changes without first acquiring authorization from the Commission to amend its exemption or acquiring a license for the project works that authorizes the project, as changed.

(c) An application to amend an exemption may be filed only by the holder of an exemption. An application to amend an exemption will be governed by the Commission's regulations governing applications for exemption. The Commission will not accept applications in competition with an application to amend an exemption, unless the Director of the Office of Energy Projects determines that it is in the public interest to do so.

[Order 413, 50 FR 11688, Mar. 25, 1985, as amended by Order 699, 72 FR 45324, Aug. 14, 2007]

§ 4.105 Action on exemption applications.

(a) *Exemption from provisions other than licensing.* An application for exemption of a small hydroelectric power project from provisions of Part I of the Act other than the licensing requirement will be processed and considered as part of the related application for license or amendment of license.

(b) (1) *Consultation.* The Commission will circulate a notice of application for exemption from licensing to interested agencies and Indian tribes at the time the applicant is notified that the application is accepted for filing.

(2) *Non-standard terms and conditions.* In approving any application for exemption from licensing, the Commission may prescribe terms or conditions in addition to those set forth in §4.106 in order to:

(i) Protect the quality or quantity of the related water supply;
(ii) Otherwise protect life, health, or property;
(iii) Avoid or mitigate adverse environmental impact; or
(iv) Better conserve, develop, or utilize in the public interest the water resources of the region.

(Energy Security Act of 1980, Pub. L. 96–294, 94 Stat. 611; Federal Power Act, as amended (16 U.S.C. 792–828c); Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2601–2645); and the Department of Energy Organization Act (42 U.S.C. 7101–7352); E.O. 12009, 3 CFR 142 (1978))

[Order 106, 45 FR 76123, Nov. 18, 1980, as amended by Order 202, 47 FR 4246, Jan. 29, 1982; Order 413, 50 FR 11688, Mar. 25, 1985; Order 533, 56 FR 23154, May 20, 1991]

§ 4.106 Standard terms and conditions of case-specific exemption from licensing.
Any case-specific exemption from licensing granted for a small hydroelectric power project is subject to the following standard terms and conditions:

(a) *Article 1.* The Commission reserves the right to conduct investigations under sections 4(g), 306, 307, and 311 of the Federal Power Act with respect to any acts, complaints, facts, conditions, practices, or other matters related to the construction, operation, or maintenance of the exempt project. If any term or condition of the exemption is violated, the Commission may revoke the exemption, issue a suitable order under section 4(g) of the Federal Power Act, or take appropriate action for enforcement, forfeiture, or penalties under Part III of the Federal Power Act.

(b) *Article 2.* The construction, operation, and maintenance of the exempt project must comply with any terms and conditions that the United States Fish and Wildlife Service, the National Marine Fisheries Service, and any state fish and wildlife agencies have determined are appropriate to prevent loss of, or damage to, fish or wildlife resources or otherwise to carry out the purposes of the Fish and Wildlife Coordination Act, as specified in exhibit E of the application for exemption from licensing or in the comments submitted in response to the notice of exemption application.

(c) *Article 3.* The Commission may revoke this exemption if actual construction of any proposed generating facilities has not begun within two years or has not been completed within four years from the date on which this exemption was granted. If an exemption is revoked under this article, the Commission will not accept from the prior exemption holder a subsequent application for exemption from licensing for the same project within two years of the revocation.

(d) *Article 4.* This exemption is subject to the navigation servitude of the United States if the project is located on navigable waters of the United States.

(e) *Article 5.* This exemption does not confer any right to use or occupy any Federal lands that may be necessary for the development or operation of the project. Any right to use or occupy any Federal lands for those purposes must be obtained from the administering Federal land agencies. The Commission may accept a license application submitted by any qualified license applicant and revoke this exemption, if any necessary right to use or occupy Federal lands for those purposes has not been obtained within one year from the date on which this exemption was granted.

(f) *Article 6.* In order to best develop, conserve, and utilize in the public interest the water resources of the region, the Commission may require that the exempt facilities be modified in structure or operation or may revoke this exemption.
(g) *Article 7.* The Commission may revoke this exemption if, in the application process, material discrepancies, inaccuracies, or falsehoods were made by or on behalf of the applicant.

(h) *Article 8.* Any exempted small hydroelectric power project that utilizes a dam that is more than 33 feet in height above streambed, as defined in 18 CFR 12.31(c) of this chapter, impounds more than 2,000 acre-feet of water, or has a significant or high hazard potential, as defined in 33 CFR part 222, is subject to the following provisions of 18 CFR part 12, as it may be amended:

(1) Section 12.4(b)(1) (i) and (ii), (b)(2) (i) and (iii), (b)(iv), and (b)(v);
(2) Section 12.4(c);
(3) Section 12.5;
(4) Subpart C; and
(5) Subpart D.

For the purposes of applying these provisions of 18 CFR part 12, the exempted project is deemed to be a licensed project development and the owner of the exempted project is deemed to be a licensee.

(i) Before transferring any property interests in the exempt project, the exemption holder must inform the transferee of the terms and conditions of the exemption. Within 30 days of transferring the property interests, the exemption holder must inform the Commission of the identity and address of the transferee. [Order 106, 45 FR 76123, Nov. 18, 1980; 45 FR 77420, Nov. 24, 1980, as amended by Order 202, 47 FR 4246, Jan. 29, 1982; Order 413, 50 FR 11688, Mar. 25, 1985; Order 482, 52 FR 39630, Oct. 23, 1987; Order 413–A, 56 FR 31331, July 10, 1991]

§ 4.107 Contents of application for exemption from licensing.

(a) *General requirements.* An application for exemption from licensing submitted under this subpart must contain the introductory statement, the exhibits described in this section, and, if the project structures would use or occupy any lands other than Federal lands, an appendix containing documentary evidence showing that applicant has the real property interests required under §4.31(c)(2)(ii). The applicant must identify in its application all Indian tribes that may be affected by the project.

(b) *Introductory statement.* The application must include an introductory statement that conforms to the following format:
Before the Federal Energy Regulatory Commission
Application for Exemption of Small Hydroelectric Power Project From Licensing

(1) [Name of applicant] applies to the Federal Energy Regulatory Commission for an exemption for [name of project], a small hydroelectric power project that is proposed to have an installed capacity of 5 megawatts or less, from licensing under the Federal Power Act. [If applicable: The project is currently licensed as FERC Project No. ____.]

(2) The location of the project is:
[State or territory]____________________

____
[County]____________________
[Township or nearby town]____________________

____
[Stream or body of water]____________________

____

(3) The exact name and business address of each applicant are:

____
____
____

(4) The exact name and business address of each person authorized to act as agent for the applicant in this application are:

____
____
____

(5) [Name of applicant] is [specify, as appropriate: a citizen of the United States or other identified nation; an association of citizens of the United States or other identified nation; a municipality; a state; or a corporation incorporated under the laws of (specify the United States or the state or nation of incorporation, as appropriate).]

(c) *Exhibit A.* Exhibit A must describe the small hydroelectric power project and its proposed mode of operation. To the extent feasible, the information in this exhibit may be submitted in tabular form. The applicant must submit the following information:

(1) A brief description of any existing dam and impoundment proposed to be utilized by the small hydroelectric power project and any other existing or proposed project works and appurtenant

facilities, including intake facilities, diversion structures, powerhouses, primary transmission lines, penstocks, pipelines, spillways, and other structures, and the sizes, capacities, and construction materials of those structures.

(2) The number of existing and proposed generating units at the project, including auxiliary units, the capacity of each unit, any provisions for future units, and a brief description of any plans for retirement or rehabilitation of existing generating units.

(3) The type of each hydraulic turbine of the small hydroelectric power project.

(4) A description of how the power plant is to be operated, that is, run-of-river or peaking.

(5) A graph showing a flow duration curve for the project. Identify stream gauge(s) and period of record used. If a synthetic record is utilized, provide details concerning its derivation. Furnish justification for selection of installed capacity if the hydraulic capacity of proposed generating unit(s) plus the minimum flow requirements, if not usable for power production, is less than the stream flow that is exceeded 25 percent of the time.

(6) Estimations of:

(i) The average annual generation in kilowatt-hours;
(ii) The average and design head of the power plant;
(iii) The hydraulic capacity of each turbine of the power plant (flow through the plant) in cubic feet per second;
(iv) The number of surface acres of the man-made or natural impoundment used, if any, at its normal maximum surface elevation and its net and gross storage capacities in acre-feet.

(7) The planned date for beginning and completing the proposed construction or development of generating facilities.

(8) A description of the nature and extent of any repair, reconstruction, or other modification of a dam that would occur in association with construction or development of the proposed small hydroelectric power project, including a statement of the normal maximum surface area and normal maximum surface elevation of any existing impoundment before and after construction.

(d) *Exhibit G.* Exhibit G is a map of the project and boundary and must conform to the specifications of §4.41(h) of this chapter.

(e) *Exhibit E.* This exhibit is an environmental report that must include the following information, commensurate with the scope and environmental impact of the construction and operation of the small hydroelectric power project. *See* §4.38 for consultation requirements.

(1) A description of the environmental setting of the project, including vegetative cover, fish and wildlife resources, water quality and quantity, land and water uses, recreational uses, historical and archeological resources, and scenic and aesthetic resources. The report must list any endangered or threatened plant and animal species, any critical habitats, and any sites eligible for or included on the National Register of Historic Places. The applicant may obtain assistance in the preparation of this information from state natural resources agencies, the state historic preservation officer, and from local offices of Federal natural resources agencies.

(2) A description of the expected environmental impacts from the proposed construction or development and the proposed operation of the small hydroelectric power project, including any impacts from any proposed changes in the capacity and mode of operation of the project if it is already generating electric power, and an explanation of the specific measures proposed by the applicant, the agencies consulted, and others to protect and enhance environmental resources and values and to mitigate adverse impacts of the project on such resources.

(3) Any additional information the applicant considers important.

(f) *Exhibit F.* Exhibit F is a set of drawings showing the structures and equipment of the small hydroelectric facility and must conform to the specifications of §4.41(g) of this chapter.

[Order 106, 45 FR 76123, Nov. 18, 1980, as amended by Order 225, 47 FR 19056, May 3, 1982; Order 413, 50 FR 11689, Mar. 25, 1985; Order 494, 53 FR 15381, Apr. 29, 1988; Order 533, 56 FR 23154, May 20, 1991; Order 2002, 68 FR 51121, Aug. 25, 2003; Order 699, 72 FR 45324, Aug. 14, 2007]

§ 4.108 Contents of application for exemption from provisions other than licensing.
An application for exemption of a small hydroelectric power project from provisions of Part I of the Act other than the licensing requirement need not be prepared according to any specific format, but must be included as an identified appendix to the related application for license or amendment of license. The application for exemption must list all sections or subsections of Part I of the Act for which exemption is requested.

[Order 106, 45 FR 76123, Nov. 18, 1980]

Title 18: Conservation of Power and Water Resources
PART 4—LICENSES, PERMITS, EXEMPTIONS, AND DETERMINATION OF PROJECT COSTS

Subpart J—Exemption of Small Conduit Hydroelectric Facilities
§ 4.90 Applicability and purpose.

This subpart implements section 30 of the Federal Power Act and provides procedures for obtaining an exemption for constructed or unconstructed small conduit hydroelectric facilities, as defined in §4.30(b)(28), from all or part of the requirements of Part I of the Federal Power Act, including licensing, and the regulations issued under Part I.

[Order 76, 45 FR 28090, Apr. 28, 1980, as amended by Order 413, 50 FR 11686, Mar. 25, 1985; Order 2002, 68 FR 51121, Aug. 25, 2003]

§ 4.91 [Reserved]

§ 4.92 Contents of exemption application.
(a) An application for exemption for this subpart must include:

(1) An introductory statement, including a declaration that the facility for which application is made meets the requirements of §4.30(b)(28), the facility qualifies but for the discharge requirement of §4.30(b)(28)(v), the introductory statement must identify that fact and state that the application is accompanied by a petition for waiver of §4.30(b)(28)(v), filed pursuant to §385.207 of this chapter);

(2) Exhibits A, E, F, and G.

(3) An appendix containing documentary evidence showing that the applicant has the real property interests required under §4.31(b); and

(4) Identification of all Indian tribes that may be affected by the project.

(b) *Introductory Statement.* The introductory statement must be set forth in the following format:
Before the Federal Energy Regulatory Commission
Application for Exemption for Small Conduit Hydroelectric Facility [Name of applicant] applies to the Federal Energy Regulatory Commission for an exemption for the [name of facility], a small conduit hydroelectric facility that meets the requirements of [insert the following language, as appropriate: "§4.30(b)(28) of this subpart" or "§4.30(b)(28) of this subpart, except paragraph

(b)(28)(v)"], from certain provisions of Part I of the Federal Power Act.
The location of the facility is:
State or Territory:____________________
County:____________________
Township or nearby town:____________________
The exact name and business address of each applicant is:

____

The exact name and business address of each person authorized to act as agent for the applicant in this application is:

____

[Name of applicant] is [a citizen of the United States, an association of citizens of the United States, a municipality, State, or a corporation incorporated under the laws of (specify the United States or the state of incorporation, as appropriate), as appropriate].
The provisions of Part I of the Federal Power Act for which exemption is requested are:
[List here all sections or subsections for which exemption is requested.]

[If the facility does not meet the requirement of §4.30(b)(28)(v), add the following sentence: "This application is accompanied by a petition for waiver of §4.30(b)(28)(v), submitted pursuant to 18 CFR 385.207."]

(c) *Exhibit A.* Exhibit A must describe the small conduit hydroelectric facility and proposed mode of operation with appropriate references to Exhibits F and G. To the extent feasible the information in this exhibit may be submitted in tabular form. The following information must be included:

(1) A brief description of any conduits and associated consumptive water supply facilities, intake facilities, powerhouses, and any other structures associated with the facility.

(2) The proximate natural sources of water that supply the related conduit.

(3) The purposes for which the conduit is used.

(4) The number of generating units, including auxiliary units, the capacity of each unit, and provisions, if any, for future units.

(5) The type of each hydraulic turbine.

(6) A description of how the plant is to be operated, manually or automatically, and whether the plant is to be used for peaking.

(7) Estimations of:
(i) The average annual generation in kilowatt hours;
(ii) The average head of the plant;
(iii) The hydraulic capacity of the plant (flow through the plant) in cubic feet per second;
(iv) The average flow of the conduit at the plant or point of diversion (using best available data and explaining the sources of the data and the method of calculation); and
(v) The average amount of the flow described in paragraph (c)(7)(iv) of this section available for power generation.

(8) The planned date for beginning construction of the facility.

(9) If the hydroelectric facility discharges directly into a natural body of water and a petition for waiver of §4.30(b)(28)(v) has not been submitted, evidence that a quantity of water equal to or greater than the quantity discharged from the hydroelectric facility is withdrawn from that water body downstream into a conduit that is part of the same water supply system as the conduit on which the hydroelectric facility is located.

(10) If the hydroelectric facility discharges directly to a point of agricultural, municipal, or industrial consumption, a description of the nature and location of that point of consumption.

(11) A description of the nature and extent of any construction of a dam that would occur in association with construction of the proposed small conduit hydroelectric facility, including a statement of the normal maximum surface area and normal maximum surface elevation of any existing impoundment before and after that construction; and any evidence that the construction would occur for agricultural, municipal, or industrial consumptive purposes even if hydroelectric generating facilities were not installed.

(d) *Exhibit G.* Exhibit G is a map of the project and boundary and must conform to the specifications of §4.41(h) of this chapter.

(e) *Exhibit E.* This exhibit is an Environmental Report. It must be prepared pursuant to §4.38 and must include the following information, commensurate with the scope and environmental impact of the facility's construction and operation:

(1) A description of the environmental setting in the vicinity of the facility, including vegetative cover, fish and wildlife resources, water quality and quantity, land and water uses, recreational use, socio-economic conditions, historical and archeological resources, and visual resources. The report must give special attention to endangered or threatened plant and animal species, critical habitats, and sites eligible for or included on the National Register of Historic Places. The applicant may obtain assistance in the preparation of this information from State natural resources agencies, the State historic preservation officer, and from local offices of Federal natural resources agencies.

(2) A description of the expected environmental impacts resulting from the continued operation of an existing small conduit hydroelectric facility, or from the construction and operation of a proposed small conduit hydroelectric facility, including a discussion of the specific measures proposed by the applicant and others to protect and enhance environmental resources and to mitigate adverse impacts of the facility on them.

(3) A description of alternative means of obtaining an amount of power equivalent to that provided by the proposed or existing facility.

(4) Any additional information the applicant considers important.

(f) *Exhibit F.* Exhibit F is a set of drawings showing the structures and equipment of the small conduit hydroelectric facility and must conform to the specifications of §4.41(g) of this chapter.

[Order 76, 45 FR 28090, Apr. 28, 1980, as amended by Order 413, 50 FR 11686, Mar. 25, 1985; Order 533, 56 FR 23153, May 20, 1991; Order 2002, 68 FR 51121, Aug. 25, 2003; Order 699, 72 FR 45324, Aug. 14, 2007]

§ 4.93 Action on exemption applications.

(a) An application for exemption that does not meet the eligibility requirements of §4.30(b)(28)(v) may be accepted, provided the application has been accompanied by a request for waiver under §4.92(a)(1) and the waiver request has not been denied. Acceptance of an application that has been accompanied by a request for waiver under §4.92(a)(1) does not constitute a ruling on the waiver request, unless expressly stated in the acceptance.

(b) The Commission will circulate a notice of application for exemption to interested agencies and Indian tribes at the time the applicant is notified that the application is accepted for filing.
(c) In granting an exemption the Commission may prescribe terms or conditions in addition to those set forth in §4.94, in order to:
(1) Protect the quality or quantity of the related water supply for agricultural, municipal, or industrial consumption;
(2) Otherwise protect life, health, or property;
(3) Avoid or mitigate adverse environmental impact; or
(4) Conserve, develop, or utilize in the public interest the water power resources of the region.

(d) *Conversion to license application.*
(1) If an application for exemption under this subpart is denied by the Commission, the applicant may convert the exemption application into an application for license for the hydroelectric project.
(2) The applicant must provide the Commission with written notification, within 30 days after the date of issuance of the order denying exemption, that it intends to convert the exemption application into a license application. The applicant must submit to the Commission, no later than 90 days after the date of issuance of the order denying exemption, additional information that is necessary to conform the exemption application to the relevant regulations for a license application.
(3) If all the information timely submitted is found sufficient, together with the application for exemption, to conform to the relevant regulations for a license application, the converted

application will be considered *accepted for filing* as of the date that the exemption application was accepted for filing.

[Order 76, 45 FR 28090, Apr. 28, 1980, as amended by Order 413, 50 FR 11687, Mar. 25, 1985; Order 533, 56 FR 23153, May 20, 1991; Order 2002, 68 FR 51121, Aug. 25, 2003]

§ 4.94 Standard terms and conditions of exemption.

Any exemption granted under §4.93 for a small conduit hydroelectric facility is subject to the following standard terms and conditions:

(a) *Article 1.* The Commission reserves the right to conduct investigations under sections 4(g), 306, 307, and 311 of the Federal Power Act with respect to any acts, complaints, facts, conditions, practices, or other matters related to the construction, operation, or maintenance of the exempt facility. If any term or condition of the exemption is violated, the Commission may revoke the exemption, issue a suitable order under section 4(g) of the Federal Power Act, or take appropriate action for enforcement, forfeiture, or penalties under Part III of the Federal Power Act.

(b) *Article 2.* The construction, operation, and maintenance of the exempt project must comply with any terms and conditions that the United States Fish and Wildlife Service, the National Marine Fisheries Service, and any state fish and wildlife agencies have determined are appropriate to prevent loss of, or damage to, fish or wildlife resources or otherwise to carry out the purposes of the Fish and Wildlife Coordination Act, as specified in exhibit E of the application for exemption from licensing or in the comments submitted in response to the notice of exemption application.

(c) *Article 3.* The Commission may revoke this exemption if actual construction of any proposed generating facilities has not begun within two years or has not been completed within four years from the effective date of this exemption. If an exemption is revoked under this article, the Commission will not accept from the prior exemption holder a subsequent application for exemption from licensing or a notice of exemption from licensing for the same project within two years of the revocation.

(d) *Article 4.* In order to best develop, conserve, and utilize in the public interest the water resources of the region, the Commission may require that the exempt facilities be modified in structure or operation or may revoke this exemption.

(e) *Article 5.* The Commission may revoke this exemption if, in the application process, material discrepancies, inaccuracies, or falsehoods were made by or on behalf of the applicant.

(f) *Article 6.* Before transferring any property interests in the exempt project, the exemption holder must inform the transferee of the terms and conditions of the exemption. Within 30 days of transferring the property interests, the exemption holder must inform the Commission of the identity and address of the transferee.

[Order 76, 45 FR 28090, Apr. 28, 1980, as amended by Order 413, 50 FR 11687, Mar. 25, 1985; Order 413–A, 56 FR 31331, July 10, 1991]

§ 4.95 Surrender of exemption.

(a) To voluntarily surrender its exemption, a holder of an exemption for a small conduit hydroelectric facility must file a petition with the Commission.

(b) (1) If construction has begun, prior to filing a petition with the Commission, the exemption holder must consult with the fish and wildlife agencies in accordance with §4.38, substituting for the information required under §4.38(b)(1) information appropriate to the disposition and restoration of the project works and lands. The petition must set forth the exemption holder's plans with respect to disposition and restoration of the project works and lands.

(2) If construction has begun, public notice of the petition will be given, and, at least 30 days thereafter, the Commission will act upon the petition.

(c) If no construction has begun, unless the Commission issues an order to the contrary, the exemption will remain in effect through the thirtieth day after the Commission issues a public notice of receipt of the petition. New applications involving the site of the surrendered exemption may be filed on the next business day.

(d) Exemptions may be surrendered only upon fulfillment by the exemption holder of such obligations under the exemption as the Commission may prescribe and, if construction has begun, upon such conditions with respect to the disposition of such project works and restoration of project lands as may be determined by the Commission and the Federal and state fish and wildlife agencies.

[Order 413, 50 FR 11687, Mar. 25, 1985]

§ 4.96 Amendment of exemption.

(a) An exemption holder must construct and operate its project as described in the exemption application approved by the Commission or its delegate.

(b) If an exemption holder desires to change the design, location, method of construction or operation of its project, it must first notify the appropriate Federal and state fish and wildlife agencies and inform them in writing of the changes it intends to implement. If these agencies determine that the changes would not cause the project to violate the terms and conditions imposed by the agencies, and if the changes would not materially alter the design, location, method of construction or operation of the project, the exemption holder may implement the changes. If any of these agencies determines that the changes would cause the project to violate the terms and conditions imposed by the agencies, or if the changes would materially alter the design, location, method of construction or the operation of the project works, the exemption holder may not implement the changes without first acquiring authorization from the Commission to amend its exemption, or acquiring a license that authorizes the project, as changed.

(c) An application to amend an exemption may be filed only by the holder of the exemption. An application to amend an exemption will be governed by the Commission's regulations governing applications for exemption. The Commission will not accept applications in competition with an application to amend an exemption, unless the Director of the Office of Energy Projects determines that it is in the public interest to do so.

[Order 413, 50 FR 11687, Mar. 25, 1985, as amended by Order 699, 72 FR 45324, Aug. 14, 2007]