Los Medanos Energy Center; Plant #11866
750 East Third Street, Pittsburg CA 95465

BACKGROUND

The Los Medanos Energy Center (LMEC) is applying for a modification to the Authority to Construct issued under application 18595 for the equipment listed below. Because that authority to construct also served as a federal PSD permit and since the LMEC has not yet been constructed or operated, the modified authority to construct for the LMEC must be reviewed as a "new" application with respect to the PSD impact analysis and is therefore subject to public comment and review pursuant to Regulation 2-2-405 and 2-2-406.

S-1 Combustion Gas Turbine #1, General Electric Frame 7FA Model PG 7241 or equivalent; 1,929 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-1 Selective Catalytic Reduction System and A-2 Oxidation Catalyst

S-2 Heat Recovery Steam Generator #1, equipped with dry low-NO_x Duct Burners, 83 MM BTU per hour, abated by A-1 Selective Catalytic Reduction System and A-2 Oxidation Catalyst

S-3 Combustion Gas Turbine #2, General Electric Frame 7FA Model PG 7241 or equivalent; 1,929 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-3 Selective Catalytic Reduction System and A-4 Oxidation Catalyst

S-4 Heat Recovery Steam Generator #2, equipped with dry low-NO_x Duct Burners, 83 MM BTU per hour, abated by A-3 Selective Catalytic Reduction System and A-4 Oxidation Catalyst

S-5 Auxiliary Steam Boiler, 266 MM BTU per hour, equipped with low-NO_x burners

The original application for this cogeneration facility was submitted by Enron and permitted as the Pittsburg District Energy Facility with the equipment specifications listed above. The "facility" has been purchased by Calpine, which has determined that the following equipment modifications are necessary for its efficient operation.

- The heat input rating of each HRSG duct burner will increase from 83 MM BTU/hr (HHV) to 333 MM BTU/hr (HHV)
- The auxiliary boiler heat input rating will increase from 266 MM BTU/hr (HHV) to 320 MM BTU/hr (HHV) and the boiler will be abated by SCR for NO_x control
- the cooling tower will increase in size from 6 to 8 cells
- A 600 kW (300 hp) fire pump diesel engine (exempt from permit) will be added
- A 600 kW, natural-gas fired emergency generator (exempt from permit) will be added

As a result of these modifications and revised emission specifications, the following changes in operating parameters and emission rates will occur:

- Reduce allowable NO_x, CO, and POC emission rates during gas turbine start-ups to levels consistent with those used for the Delta Energy Center. No distinction will be made between hot and cold start-ups – instead, all start-ups will be subject to one set of mass limits for NO_x, CO, and POC. SO_2 and PM_{10} emission rates (lb/MM BTU), which are not affected during turbine start-up, will not change.
- Allowable heat input rates for HRSG duct burners and auxiliary boiler will increase
- CO, NO_x, POC, PM_{10}, and SO_2 mass emission rates and limits for the gas turbine/HRSGs and the auxiliary boiler will be revised to reflect increased fuel usage and reduced start-up emission rates
- Annual Toxic Air Contaminant emission rates will increase due to increased fuel usage
- Cooling tower TAC emission rates will be revised to reflect Calpine's estimates of water TDS and cooling tower drift rate

Heat Input Rates

Based upon the increases in the rated heat input rates for the HRSG duct burners and auxiliary boiler, the maximum heat input rates for the LMEC will be revised as shown in Table 2 below.

Table 1 Current Maximum Heat Input Rates

Source	MM BTU/hour	MM BTU/day	MM BTU/year
Each Gas Turbine	1,929	46,296	15,586,320
Each Gas Turbine with HRSG Duct Burner Firing	2,012	48,288	16,256,960[a]
Auxiliary Boiler	266	6,384	399,000
CTGs, HRSGs, & Auxiliary Boiler Combined	4,290	102,960	32,912,920[b]

[a]based upon 8,080 hours of simultaneous gas turbine and HRSG duct burner firing per year @ 100% load

[b]limited by permit condition

Table 2 Revised Maximum Heat Input Rates

Source	MM BTU/hour	MM BTU/day	MM BTU/year
Each Gas Turbine	1,925.1	46,202.4	15,505,200
Each Gas Turbine with HRSG Duct Burner Firing	2,225.1	50,738.4[a]	17,005,200[b]
Auxiliary Boiler	320	7,680	480,000[c]
CTGs, HRSGs, & Auxiliary Boiler Combined	4770.2	109,156.8	34,490,400

[a]based upon maximum 16 hr/day gas turine operation with duct burner firing and 8 hr/day gas turbine firing without duct burner at an average heat input rate of 1,892.1 MM BTU/hr

[b]based upon 5000 hours of duct burner firing per year per HRSG and an average gas turbine heat input rate of 1,770 MM BTU/hr for 3,760 hr/year

[c]based upon 1,500 hours per year operation at its maximum firing rate of 320 MM BTU/hr

CRITERIA-POLLUTANT EMISSION SUMMARY

Annual Average Project Emissions Increase:

Pollutant	lb/day	ton/yr[a]
NO_x	123.3	22.5
CO	103.6	18.9
POC	0	0
PM_{10}	44.1	8.05
SO_2	39.7	7.25
NPOC	0	0

[a]based upon limits in permit condition #33

Daily Maximum Emissions by Source (lb/day):

Source	NO_x	CO	POC	PM_{10}	SO_2	NPOC
S-1 Gas Turbine	603.8	3,047.6	78.5	312	127.2	0
S-2 HRSG	48	70.4	8.2	52.8	14.8	0
S-3 Gas Turbine	603.8	3,047.6	78.5	312	127.2	0
S-4 HRSG	48	70.4	8.2	52.8	14.8	0
S-5 Auxiliary Boiler	83	280.3	41.5	38.4	11	0

EMISSION CALCULATIONS

S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators

Start-Up Emission Rates

Table 3 Current Turbine Start-Up Emission Rates

Start-Up Type	NO_x	CO	POC
Cold Start (lb/hr)	223	1821	239
Cold Start[a] (lb/start)	280	3,393	359
Hot Start[b] (lb/start)	223	1,821	239

[a]based upon maximum cold start duration of 3 hours

[b]based upon maximum hot start duration of 1 hour

Calpine is proposing to modify the turbine start-up emission rates based upon their vendor guarantees and their best estimates of probable emission rates. The revised emission rates shown in Table 4 were used in the permitting of the Delta Energy Center and Metcalf Energy Center.

Table 4 Revised Turbine Start-Up Emission Rates

	NO_x	CO	POC
Start-Up (lb/hr)	80	902	16
Start-Up (lb/start-up)	240	2,514	48

Baseload Emission Factors

Table 5 Controlled Regulated Air Pollutant Emission Factors (lb/MM BTU)

Pollutant	Source			
	CTG	HRSG	CTG & HRSG Combined	Auxiliary Boiler
Nitrogen Oxides (as NO_2)	0.009[a]	0.009[a]	0.009[a]	0.0107
Carbon Monoxide	0.0132[b]	0.0132[b]	0.0132[b]	0.0365
Precursor Organic Compounds	0.00136	0.01	0.0017	0.00137
Particulate Matter (PM_{10})	0.00845	0.00845	0.00845	0.005
Sulfur Dioxide	0.00277	0.00277	0.00277	0.00277

[a]based upon the permit condition emission limit of 2.5 ppmvd NO_x @ 15% O_2

[b]based upon the permit condition emission limit of 6 ppmvd CO @ 15% O_2

Table 6 Revised Controlled Regulated Air Pollutant Emission Factors (lb/MM BTU)

Pollutant	Source			
	CTG	HRSG	CTG & HRSG Combined	Auxiliary Boiler
Nitrogen Oxides (as NO_2)	0.009[a]	0.009[a]	0.009[a]	0.0108
Carbon Monoxide	0.0132[b]	0.0132[b]	0.0132[b]	0.0365
Precursor Organic Compounds	0.0017	0.0015	0.0017	0.0054
Particulate Matter (PM_{10})	0.0073	0.0073	0.0073	0.005
Sulfur Dioxide	0.00277	0.00277	0.00277	0.00277

[a]based upon the permit condition emission limit of 2.5 ppmvd NO_x @ 15% O_2

[b]based upon the permit condition emission limit of 6 ppmvd CO @ 15% O_2

Maximum Hourly Emission Rates

Table 7 Current Maximum Hourly Regulated Air Pollutant Emission Rates (lb/hr)

Pollutant	Source	
	CTG[a]	CTG & HRSG Combined[b]
Nitrogen Oxides (as NO_2)	17.36	17.5
Carbon Monoxide	25.46	26.56
Precursor Organic Compounds	2.6	3.43
Particulate Matter (PM_{10})	16.3	17.0
Sulfur Dioxide	5.34	5.6

[a]maximum heat input rate of 1,929 MM BTU/hr (HHV)

[b]maximum combined heat input rate of 2,012 MM BTU/hr (HHV)

Table 8 Revised Maximum Hourly Regulated Air Pollutant Emission Rates (lb/hr)

Pollutant	Source	
	CTG	CTG & HRSG Combined
Nitrogen Oxides (as NO_2)	17.33	20.0
Carbon Monoxide	25.3	29.2
Precursor Organic Compounds	3.3	3.6
Particulate Matter (PM_{10})	13	16.3
Sulfur Dioxide	5.0	5.8

Maximum Daily Emission Rates

Table 9 Maximum Daily Regulated Air Pollutant Emissions By Source (lb/day)

	NO_2[c]	CO	POC	PM_{10}	SO_2
S-1 CTG & S-2 HRSG[a]	688.4	2,656.5	551.17	408	133.76
S-3 CTG & S-4 HRSG[a]	688.4	2,656.5	551.17	408	133.76
S-5 Auxiliary Boiler[b]	68.3	233	8.75	31.9	17.2

[a]based upon one 1 hour hot startup, 22.5 hours of full load operation @ 2,012 MM BTU/hr, and one 0.5 hour shutdown in one day. For example, NO_x emissions are calculated as follows:

223 lb/SU + 58 lb/SD + (2,012 MM BTU/hr)(0.009 lb NO_x/MM BTU)(22.5 hr/day)
= 688.4 lb NO_x/day

[b]based upon 24 hour/day operation of the Auxiliary Boiler at its maximum rated heat input of 266 MM BTU/hr

Table 10 Revised Maximum Daily Regulated Air Pollutant Emissions By Source (lb/day)

	NO_x	CO	POC	PM_{10}	SO_2
Each Gas Turbine[a] (S-1, S-3)	603.8	3,047.6	78.5	312	127.2
Each HRSG (S-2, S-4)	48	70.4	8.2	52.8	14.8
Each Power Train[b] (S-1 & S-2, S-3 & S-4)	615.3	3,064.5	118.9	340.4	130.5

S-5 Auxiliary Boiler[c]	83	280.3	41.5	38.4	11

[a]based upon one 3-hour start-up and 21 hours of baseload operation without duct burner firing @ 1925.1 MM BTU/hr. For example, NO_x emissions are calculated as follows:

240 lb/SU + (1925.1 MM BTU/hr)(0.009 lb NO_x/MM BTU)(21 hr/day) = 603.8 lb NO_x/day

[b]based upon one 3-hour start-up, 16 hours of full load operation with duct burner firing @ 2,125.1 MM BTU/hr, and 4 hour of baseload operation without duct burner firing @ 1925.1 MM BTU/hr. For example, NO_x emissions are calculated as follows:

240 lb/SU + (2,125.1 MM BTU/hr)(0.009 lb NO_x/MM BTU)(16 hr/day) +
(1925.1 MM BTU/hr)(0.009 lb NO_x/MM BTU)(4 hr/day) = 615.3 lb NO_x/day

[c]based upon 24 hour/day operation of the Auxiliary Boiler at its maximum rated heat input of 320 MM BTU/hr

Table 11 Worst-Case Daily Facility Regulated Air Pollutant Emissions (lb/day)

	NO_x	CO	POC	PM_{10}	SO_2
S-1 CTG 3-hr Start-up	240	2,514	48	39	15
S-1 CTG Baseload Operation (5 hr/day)	86.65	126.5	15	65	25
S-1 CTG Baseload with S-2 HRSG Duct Burner[a]	320	467.2	54.9	260.8	100.8
S-3 CTG 3-hr Start-up[b]	240	2,514	48	39	15
S-3 CTG Baseload Operation (3 hr/day)	52	75.9	9	39	15
S-3 CTG Baseload with S-4 HRSG Duct Burner[a]	320	467.2	54.9	260.8	100.8
S-5 Auxiliary Boiler[c]	83	280.3	41.5	38.4	11
Total	**1,341.7**	**6,445.1**	**271.3**	**742**	**282.6**

[a]based upon 16 hours baseload operation with duct burner firing at maximum combined heat input of 2,225.1 MM BTU/hr

[b]occurs in second hour of 24-hr period

[c]based upon 24-hour operation at maximum rated heat input of 320 MM BTU/hr

Annual Emission Rates

Basis:

5,200 hours of baseload (100% load) operation per CTG per year @ 50°F
1,664 hours of 60% load operation per CTG per year @ 50°F
312 one hour (hot) CTG start-ups
312 half hour CTG shutdowns per year.

Table 12 Current Annual Regulated Air Pollutant Emissions for CTGs and HRSGs

Source (Operating Mode)	NO_x (lb/yr)	CO (lb/yr)	POC (lb/yr)	PM_{10} (lb/yr)	SO_2 (lb/yr)
S-1 and S-3 CTGs (312 hot start-ups)	69,576	568,152	74,568	5,304	1,747.2
S-1 and S-3 CTGs (312 shutdowns)	18,096	74,256	78,936	2,652	873.6
S-1 and S-3 CTGs (10,400 hrs[a] @ 100% load)	180,554.4[b]	264,813[b]	35,572.2[b]	176,814.6[d]	55,570.6[b]
S-1 and S-3 CTGs (3,328 hrs[a] @ 60% load)	37,110.5[c]	54,428.8[c]	5,607.8[c]	56,580.6[d]	11,421.8[c]
Total Emissions (lb/yr)	305,336.9	961,649.9	194,684	241,351.2	69,613.2
(ton/yr)	**152.67**	**480.8**	**97.34**	**120.67**	**34.8**

[a]total combined firing hours for both turbines

[b]based upon the maximum heat input rate of 1,929 MM BTU/hr for each CTG

[c]based upon the maximum heat input rate of 1,239 MM BTU/hr for each CTG @ 50°F and 60% load

[d]based upon the worst case PM_{10} emission rate of 17 lb/hr at the maximum combined heat input rate of 2,012 MM BTU/hr

Basis:

3,448 hours of baseload (100% load) operation per CTG per year @ 50°F
5,000 hours of CTG operation with HRSG duct burner firing per power train per year
312 start-up hours per CTG per year

Table 13 Revised Annual Regulated Air Pollutant Emissions for CTGs and HRSGs

Source (Operating Mode)	NO_x (lb/yr)	CO (lb/yr)	POC (lb/yr)	PM_{10} (lb/yr)	SO_2 (lb/yr)
S-1 and S-3 CTGs (624[a] start-up hours)	49,920	562,848	9,984	8,112	1,560
S-1 and S-3 CTGs (6,896[a] hrs @ 100% load)	109,853.3[b]	161,118.1[b]	20,688	89,648	34,480[b]
S-1 CTG and S-2 HRSG S-3 CTG and S-4 HRSG (10,000[c] hrs)	186,300[d]	273,240[d]	34,300	163,000	58,000[d]
Total Emissions (lb/yr)	346,073.3	997,206.1	64,972	260,760	94,040
(ton/yr)	**173.04**	**498.6**	**32.5**	**130.4**	**47.02**

[a]total combined firing hours for both turbines

[b]based upon an average heat input rate of 1,770 MM BTU/hr for each CTG

[c]total combined firing hours for both power trains

[d]based upon an average combined heat input rate of 2,070 MM BTU/hr for each power train

S-5 Auxiliary Boiler

Table 14 Current Regulated Air Pollutant Emissions for Auxiliary Boiler

	NO_x	CO	POC	PM_{10}	SO_2
Emission Factor[a] (lb/MM BTU)	0.0107	0.0365	0.00137	0.005	0.0027
lb/hr[b]	2.85	9.7	0.36	1.33	0.72
lb/day[c]	68.3	233	8.75	31.9	17.2
lb/yr[d]	4,269.3	14,563.5	546.6	1,995	1,077.3
ton/yr	2.13	7.28	0.27	1	0.54

[a]NO_2 emission factor is based upon BACT specification of 9 ppmv NO_x, dry @ 3% O_2. CO emission factor is based upon BACT specification of 50 ppmv, dry @ 3 % O_2. POC, and SO_2 emission factors are from AP-42, Section 1.4, Natural Gas Combustion, Table 1.4-2. PM_{10} emission factor is from AP-42, Table 1.4-1.

[b]based upon maximum heat input of 266 MM BTU/hr

[c]based upon 24 hour per day operation @ 266 MM BTU/hr or 6,384 MM BTU/day

[d]based upon a maximum 1,500 hr/yr operation and a corresponding maximum annual heat input of 399,000 MM BTU/yr

Table 15 Revised Regulated Air Pollutant Emissions for Auxiliary Boiler

	NO_x	CO	POC	PM_{10}	SO_2
Emission Factor[a] (lb/MM BTU)	0.0108	0.0365	0.0054	0.005	0.00277
lb/hr[b]	3.46	11.7	1.73	1.6	0.89
lb/day[c]	83	280.3	41.5	38.4	21.3
lb/yr[d]	5,184	17,520	2,592	2,400	1,329.6
ton/yr	2.6	8.76	1.3	1.2	0.66

[a]NO_x emission factor is based upon BACT specification of 9 ppmv NO_x, dry @ 3% O_2. CO emission factor is based upon BACT specification of 50 ppmv, dry @ 3 % O_2. POC emission factor is a vendor guarantee. SO_2 emission factor is based upon maximum sulfur content of 1 gr/dscf of natural gas. PM_{10} emission factor is from AP-42, Table 1.4-2, "Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion"

[b]based upon maximum heat input of 320 MM BTU/hr

[c]based upon 24 hour per day operation @ 320 MM BTU/hr or 7,680 MM BTU/day

[d]based upon a maximum 1,500 hr/yr operation and a corresponding maximum annual heat input of 480,000 MM BTU/yr

Table 16 Regulated Air Pollutant Emission Increases for Auxiliary Boiler

	NO_x	CO	POC	PM_{10}	SO_2
Proposed Emissions (lb/yr)	5,184	17,520	2,592	2,400	1,329.6
Current Emissions (lb/yr)	4,269.3	14,563.5	546.6	1,995	1,077.3
Difference (lb/yr)	914.7	2,956.5	2,045.4	405	252.3
Difference (ton/yr)	0.457	1.48	1.02	0.2	0.126

8-Cell Cooling Tower PM_{10} Emissions

The cooling tower is exempt from District permit requirements pursuant to Regulation 2-1-128.4. Because the cooling tower PM_{10} emissions are less than 5 tons per year, the cooling tower remains exempt from permit per Regulation 2-1-319.1. It is conservatively assumed that all particulate matter will be emitted as PM_{10}. In the original application, the cooling tower PM_{10} emission rate was estimated to be 1.9 tons per year based upon a drift rate of 0.3 gpm and a maximum total dissolved solids level of 2910 mg/l based upon 3 cycles of concentration.

Cooling tower circulation rate:	110,600 gpm
maximum total dissolved solids:	3771 ppm (3765 mg/l)
Drift rate:	0.0005 %

Water mass flow rate:

(110,600 gal/min)(60 min/hr)(8.34 lb/gal) = 55,344,240 lb/hr

Cooling tower drift rate:

(55,344,240 lb/hr)(0.000005) = 276.72 lb/hr

PM_{10} = (3771 ppm)(276.72 lb/hr)/(10^6)
= 1.043 lb/hr
= 25.04 lb/day (24 hr/day operation)
= 9,136.7 lb/yr (8,760 operating hours per year)
= 4.57 ton/yr

Toxic Air Contaminant Emission Rates

The TAC emission rates shown in Table 17 reflect the increased maximum annual heat input rates for each gas turbine/heat recovery steam generator power train of 17,005,200 MM BTU per year. It should be noted that the acrolein emission factor has been reduced based upon recent source testing of a Calpine gas turbine equipped with dry low-NOx combustors.

Table 17 Worst-Case TAC Emissions[a] for each CTG/HRSG Power Train

Toxic Air Contaminant	Emission Factor (lb/MM BTU)	Modeling Emission Rate[b] (g/sec)	Annual Emission Rate (lb/yr)
Acetaldehyde[d]	6.86E-05	1.71E-02	1,166
Acrolein	6.43E-06	1.60E-03	109
Ammonia[c]	1.22E-02	3.04	207,463
Benzene[d]	1.36E-05	3.39E-03	231
1,3-Butadiene[d]	1.27E-07	3.16E-05	2.1
Ethylbenzene	1.79E-05	4.46E-03	304
Formaldehyde[d]	1.10E-04	2.74E-02	1,870
Hexane	2.59E-04	6.45E-02	4,404
Napthalene	1.66E-06	4.14E-04	28.3
PAHs[d]	2.32E-06	5.78E-04	39.5
Propylene	7.70E-04	1.92E-01	13,094
Propylene Oxide[d]	4.78E-05	1.19E-02	812.8
Toluene	7.10E-05	1.77E-02	1,207.4
Xylene	2.61E-05	6.50E-03	443.8

[a]combined emissions from S-1 & S-3 CTGs and S-2 & S-4 HRSGs

[b]used to model annual impacts; in accordance with the current District Toxic Risk Management Policy, short term (i.e. acute) health impacts are not considered

[c]based upon the worst-case ammonia slip from the SCR system of 10 ppmvd @ 15% O_2 and 8,080 hours of operation per CTG at 100% load

[d]carcinogenic compounds

The TAC emission rates shown in Table 18 reflect the increased annual heat input rate of 480,000 MM BTU per year for the auxiliary boiler.

Table 18 Worst-Case TAC Emissions for Auxiliary Boiler

Toxic Air Contaminant	Emission Factor (lb/MM BTU)	Modeling Emission Rate[a] (g/sec)	Annual Emission Rate (lb/yr)
Acetaldehyde[b]	8.90E-06	6.26E-05	4.3
Acrolein	8.00E-07	5.62E-06	0.4
Benzene[b]	4.31E-06	3.03E-05	2.1
Ethylbenzene	2.00E-05	1.41E-04	9.6
Formaldehyde[b]	2.21E-04	1.55E-03	106
Hexane	1.30E-06	9.14E-06	0.6
Napthalene	3.00E-07	2.11E-06	0.14
PAHs[b]	1.00E-07	7.03E-07	0.05
Propylene	1.55E-04	1.09E-03	74.4
Toluene	7.80E-06	5.48E-05	3.74
Xylene	5.80E-06	4.08E-05	2.8

[a]used to model annual impacts; in accordance with the current District Toxic Risk Management Policy, short term (i.e. acute) health impacts are not considered

[b]carcinogenic compounds

Table 19 Regulated Air Pollutant Emissions for Fire Pump Diesel Engine

Pollutant	**Emission Factor**		**Annual Emissions[a]**
	g/bhp-hr	**lb/hr**	**lb/yr**
Nitrogen Oxides (as NO_2)	5.89	3.90	390
Carbon Monoxide	3.55	2.35	235
Precursor Organic Compounds	0.73	0.48	48
Particulate Matter[b] (PM_{10})	0.25	0.17	17
Sulfur Dioxide	0.167	0.11	11

[a]based upon 100 hours of operation per year for exercising

[b]classified as a toxic air contaminant by the ARB

Table 20
Worst-Case Toxic Air Contaminant Emissions for Fire Pump Diesel Engine

Toxic Air Contaminant	Emission Factor[a] (lb/MM BTU)	Annual Emissions[a] (lb/yr)
Benzene	9.33E-04	0.2
Toluene	4.09E-04	0.09
Xylenes	2.85E-04	0.06
Propylene	2.58E-03	0.54
1,3-Butadiene	3.91E-05	0.008
Formaldehyde	1.18E-03	0.25
Acetaldehyde	7.67E-04	0.2
Acrolein	9.25E-05	0.02
Total PAHs	1.68E-04	0.035

[a]based upon maximum fuel use rate of 2.11 MM BTU/hr and maximum 100 operating hours per year

Because the emission rates for these toxic air comtaminants are relatively small, the contribution to the total facility risk is negligible. Therefore, they were not input into the health risk assessment for the diesel engine. Rather, the health risk assessement for the diesel engine was based solely on its diesel particulate emissions as shown in Table 19.

Table 21 Worst-Case TAC Emissions for 6-Cell Cooling Tower[a]

Toxic Air Contaminant	Emission Factor (lb/hr)	Emission Rate (lb/yr)	Risk Screening Trigger Level (lb/yr)
Aluminum	4.5E-05	0.39	N/S[b]
Arsenic[c]	1.8E-06	0.016	0.024
Silver	2.3E-06	0.02	N/S
Barium	5.4E-06	0.05	N/S
Beryllium[c]	4.5E-06	**0.04**	**0.015**
Cadmium[c]	4.5E-06	0.04	0.046
Chloride	0.1027	900	N/S
Hexavalent chromium[c]	2.3E-06[d]	**0.02**	**0.0014**
Copper	3.2E-06	0.028	463
Fluoride	3.2E-04	2.8	N/S
Lead[c]	9.9E-06	0.087	29
Magnesium	1.2E-02	105	N/S
Manganese	6.1E-05	0.53	77
Mercury	9.1E-08	0.0008	57.9
Selenium[c]	3.2E-06	0.028	96.5
Silica[c]	1.2E-05	0.11	N/S
Sodium hydroxide	3.2E-06	0.028	926
Sulfate	8.8E-02	771	N/S
Zinc	5.6E-06	0.05	6,760

[a]based upon 24 hr/day, 365 day/yr operation of cooling towers at maximum flow rate

[b]none specified

[c]carcinogenic compound

[d]based upon the worst-case assumption that the concentration of hexavalent chromium in cooling tower water equals the detection limit of 0.005 mg/l. Cooling tower water analysis did not detect any measurable quantity of hexavalent chromium

The projected toxic air contaminant emissions from the modified cooling tower are summarized in **Table 22**. The emissions are based upon an water circulation rate of 110,600 gpm, a drift rate of 125.59 l/hr, and 8760 hours of operation per year. As shown, the cooling tower triggers a risk screening analysis pursuant to District regulation 2-1-316 for the compounds shown in bold. These emission rates reflect the increased capacity of the redesigned cooling tower. It should be noted that hexavalent chromium has been removed since it will not be used as an additive and is not expected to be present in the cooling tower water. The original assumption that hexavalent chromium is present in the cooling tower water at a a level equal to the detection limit of 0.005 mg/l is excessively conservative.

Table 22 Revised Worst-Case TAC Emissions for 8-Cell Cooling Tower

Toxic Air Contaminant	Emission Rate (lb/hr)	Annual Emission Rate[a] (lb/yr)	Risk Screening Trigger Level (lb/yr)
Aluminum	8.31E-05	0.73	N/S[b]
Arsenic[c]	3.32E-06	0.003	0.024
Beryllium	8.31E-06	**0.073**	**0.015**
Cadmium[c]	8.31E-06	**0.073**	0.046
Trivalent chromium	6.64E-06	0.058	N/S[b]
Copper	5.81E-06	0.06	463
Cyanide	8.31E-05	0.073	N/S[b]
Lead[c]	1.83E-05	0.16	29
Mercury	1.66E-07	0.0015	57.9
Nickel	8.31E-05	0.073	0.73
Selenium	5.81E-06	0.051	96.5
Silver	4.15E-06	0.036	N/S[b]
Zinc	1.04E-05	0.09	6,760

[a]based upon 24 hr/day, 365 day/yr operation of cooling tower at maximum flow rate with drift rate of 125.59 l/hr

[b]none specified

[c]carcinogenic compound

FACILITY CUMULATIVE INCREASE
(since April 5, 1991)

	Current		Increase		New Total	
	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
NO_x	839.45	153.2	123.3	22.5	962.74	175.7
CO	2,671.23	487.5	103.6	18.9	2,7748	506.4
POC	534.85	97.61	0	0	534.85	97.61
PM_{10}	677	123.55	44.1	8.05	721.1	131.6
SO_2	218.41	39.86	39.7	7.25	258.14	47.11
NPOC	0	0	0	0	0	0

TOXIC RISK SCREENING ANALYSIS

As shown in Tables 17 through 22, a health risk assessment was triggered for the gas turbines, auxiliary boiler, fire pump diesel engine, and cooling tower based upon the revised plant equipment specifications. The applicant performed and submitted a health risk assessment (HRA) utilizing approved air dispersion modeling procedures. District Toxics Section staff reviewed the analysis and determined that it was acceptable. The results of the HRA are summarized below.

Table 23 Revised Health Risk Assessment Results for LMEC[a]

Multi-pathway Carcinogenic Risk[a] (risk in one million)	Noncarcinogenic Chronic Hazard Index	Noncarcinogenic Acute Hazard Index[b]
0.32[c] 0.20[d]	0.01	0.08

[a]based upon 70 year exposure

[b]for information only; not required under current District Risk Management Policy

[c]sum of risk from gas turbines, auxiliary boiler, and cooling tower

[d]risk from fire pump diesel engine particulate emissions

As shown, the increased carcinogenic risk posed by the LMEC ($0.52/10^6$) is less than one in one million and the chronic hazard index is less than 1.0. In accordance with the District risk management policy, the impact on public health is not significant and the project is therefore acceptable.

Because the carcinogenic risk posed by the fire pump diesel engine is less than one in one million, the engine remains exempt from permit per Regulation 2-1-114.2.3.1.

Best Available Control Technology (BACT) Determinations

Pursuant to Regulation 2-2-206, BACT is defined as the more stringent of:

(a) "The most effective control device or technique which has been successfully utilized for the type of equipment comprising such a source; or

(b) The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source: or

(c) Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO, or

(d) The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations."

The type of BACT described in definitions (a) and (b) must have been demonstrated in practice and approved by a local Air Pollution Control District, CARB, or the EPA and is referred to as "BACT 2". This type of BACT is termed "achieved in practice". The BACT category described in definition (c) is referred to as "technologically feasible/cost-effective" and it must be commercially available, demonstrated to be effective and reliable on a full-scale unit, and shown to be cost-effective on the basis of dollars per ton of pollutant abated. This is referred to as "BACT 1". BACT specifications (for both the "achieved in practice" and "technologically feasible/cost-effective" categories) for various source categories have been compiled in the BAAQMD BACT Guideline.

Because each gas turbine and its associated HRSG will exhaust through a common stack and be subject to combined emission limitations, the following BACT determinations will, in practice, apply to each Gas Turbine/HRSG power train as a combined unit.

Nitrogen Oxides (NO_x)

- Combustion Gas Turbines

  District BACT Guideline 89.2.1 specifies BACT 2 (achieved in practice) for NO_x for a gas turbine with a rated heat input $\geq$ 23 MM BTU per hour as NO_x emissions < 5 ppmvd @ 15%

O_2, typically achieved through the use of Selective Catalytic Reduction (SCR) with ammonia injection in conjunction with combustion modifications. The SCAQMD BACT Guideline for gas turbines $\geq$ 3 MW specifies BACT 1 for NO_x as 2.5 ppmvd, @ 15% O_2 with an efficiency correction factor and an assumed averaging period of one hour. This BACT determination was based upon the demonstration of a SCONOX system on a 32 MW combined cycle, baseload turbine currently in operation in Vernon, California. The EPA has accepted this BACT determination as Federal LAER and further established a NO_x concentration of 2.0 ppmvd @ 15% O_2 averaged over three hours as equivalent to 2.5 ppmvd, @ 15% O_2, averaged over one hour.

In accordance with design criteria specified by the applicant, each combustion gas turbine is designed to meet a NO_x emission concentration limit of 2.5 ppmvd NO_x @ 15% O_2, averaged over one hour at, during all operating modes except gas turbine start-ups and shutdowns. This exceeds the current District BACT determination and meets the EPA and ARB BACT determination for NO_x. Compliance with this emission limitation will be achieved through the use of a selective catalytic reduction (SCR) system with ammonia injection and will be verified by a CEM located at the common stack for each gas turbine/HRSG power train.

- Heat Recovery Steam Generators (HRSGs)

  Supplemental heat will be supplied to the HRSGs with dry low-NO_x duct burners, which are designed to minimize NO_x emissions. The duct burner exhaust gases will also be abated by the SCR system with ammonia injection and when combined with the gas turbine exhaust, will achieve NO_x emission concentrations of 2.5 ppmvd @ 15% O_2, averaged over one hour.

Top-Down BACT Analysis

The following "top-down" BACT analysis for NO_x has been prepared in accordance with EPA's 1990 Draft New Source Review Workshop Manual. A "top-down" BACT analysis takes into account energy, environmental, economic, and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring.

Available Control Options and Technical Feasibility

In a March 24, 2000 letter sent to local air pollution control districts, EPA Region 9 stated that the $SCONO_x$ Catalytic Adsorption System should be included in any BACT/LAER analysis for combined cycle gas turbine power plant projects since it can achieve the BACT/LAER emission specification for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour or 2.0 ppmvd @ 15% O_2, averaged over

three hours. In this letter, EPA stated that ABB Alstom Power, the exclusive licensee for $SCONO_x$ applications, has conducted "full-scale damper testing" that demonstrates

that $SCONO_x$ is technically feasible for gas turbines of the size proposed for the Metcalf Energy Center. Stone & Webster Management Consultants, Inc. of Denver, Colorado was subsequently hired by ABB to conduct an independent technical review of the $SCONO_x$ technology as well as the full-scale damper testing program. According to the report by Stone & Webster, modifications to the actuators, fiberglass seals, and louver shaft-seal interface are being incorporated to resolve unacceptable reliability and leakage problems. However, no subsequent testing of the redesigned components has occurred to determine if the problems have been solved. Because the feasibility of the "scale-up" of the $SCONO_x$ system for large turbines has not been demonstrated, we do not consider $SCONO_x$ to be a viable control alternative for NO_x.

Although we do not consider SCONOx to be a technically feasible control alternative for this project, we have analyzed the collateral impacts of both SCR and $SCONO_x$. We are providing the following analysis for informational purposes only. The analysis shown in Table 4 applies to a single GE Frame 7FA Gas Turbine equipped with DLN combustors and a NO_x emission rate of 25 ppmvd @ 15% O_2.

Top-Down BACT Analysis Summary for NO_x

Control Alternative	Emissions[a] (ton/yr)	Emission Reduction[b] (ton/yr)	Total Annualized Cost[c] ($/yr)	Average Cost-Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)	Toxic Impacts	Adverse Environmental Impacts	Incremental Energy Impact (MM BTU/yr)
$SCONO_x$	**788**	**709**	**4,122,889**	**5,815**	**N/A[d]**	**No**	**No**	**122,000[e]**
SCR	**788**	**709**	**1,557,125**	**2,196**	**-**	**Yes**	**No**	**67,900[e]**

[a]based upon NO_x emission rate of 25 ppmvd @ 15% O_2, and annual firing rate of 17,436,780 MM BTU/yr

[b]based upon NO_x emission rate after abatement of 2.5 ppmvd @ 15% O_2, and annual firing rate of 17,436,780 MM BTU/yr

[c]"Cost Analysis for NO_x Control Alternatives for Stationary Gas Turbines", ONSITE SYCOM Energy Corporation, October 15, 1999

[d]does not apply since both control alternatives achieve the same level of emission reduction

[e]"Towantic Energy Project Revised BACT Analysis", RW Beck, February 18, 2000; based upon increased fuel use to overcome catalyst bed back pressure

Energy Impacts

As shown in the table above, the use of SCR does not result in any significant or unusual energy penalties or benefits when compared to $SCONO_x$. Although the operation and maintenance of

$SCONO_x$ does result in a greater energy penalty when compared to that of SCR, this is not considered significant enough to eliminate $SCONO_x$ as a control alternative.

Economic Impacts

According to EPA's 1990 Draft New Source Review Workshop Manual, "Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis."

As shown in the table above, the average cost-effectiveness of both SCR and $SCONO_x$ meet the current District cost-effectiveness guideline of $17,500 per ton of NO_x abated. However, the average cost-effectiveness of SCR is approximately 38% of the average cost-effectiveness of $SCONO_x$. These figures are based upon total annualized cost figures from a cost analysis conducted by ONSITE SYCOM Energy Corporation. Although SCONOx will result in greater economic impact as quantified by average cost-effectiveness, this impact is not considered adverse enough to eliminate $SCONO_x$ as a control alternative. See Appendix F for ONSITE SYSCOM cost-effectiveness calculations.

Incremental cost-effectiveness does not apply since SCR and $SCONO_x$ both achieve the current BACT/LAER standard for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour and therefore achieve the same NO_x emission reduction in tons per year.

Environmental Impacts

The use of SCR will result in ammonia emissions due to an allowable ammonia slip limit of 5 ppmvd @ 15 % O_2. A health risk assessment using air dispersion modeling showed an acute hazard index of 0.018 and a chronic hazard index of 0.0131 resulting from the ammonia slip emissions. In accordance with the District Toxic Risk Management Policy and currently accepted practice, a hazard index of 1.0 or above is considered significant. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant and is not a sufficient reason to eliminate SCR as a control alternative.

The ammonia emissions resulting from the use of SCR may have another environmental impact through its potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. However, it is the opinion of the Research and Modeling section of the BAAQMD Planning Division that the formation of ammonium nitrate in the Bay Area air basin is limited

by the formation of nitric acid and not driven by the amount of ammonia in the atmosphere. Therefore, ammonia emissions from the

proposed SCR system are not expected to contribute significantly to the increased formation of secondary particulate matter. This potential environmental impact is not considered adverse enough to justify the elimination of SCR as a control alternative.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of ammonia. Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. The MEC will be required to maintain a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases. The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards. In addition, the CEC has modeled the health impacts arising from a catastrophic release of aqueous ammonia due to spontaneous storage tank failure at the proposed MEC facility and found that the impact would not be significant. Therefore, the potential enivronmental impact due to aqueous ammonia storage at the MEC does not justify the elimination of SCR as a control alternative.

The use of SCONOx will require approximately 360,000 gallons of water per year for catalyst cleaning. This environmental impact does not justify the elimination of $SCONO_x$ as a control alternative.

Conclusion

Because both SCR and $SCONO_x$ can achieve the current accepted BACT/LAER specification for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour or 2.0 ppmvd @ 15% O_2, averaged over three hours and neither will cause significant energy, economic, or environmental impacts, neither can be eliminated as viable control alternatives. Therefore, the applicant's proposed use of SCR to meet the NO_x BACT/LAER specification is deemed acceptable.

Carbon Monoxide (CO)

BACT for CO will be analyzed within the context of three distinct operating modes for each gas turbine/HRSG power train. The first mode is firing of the gas turbine only over its entire operating range from minimum to maximum load. The second mode includes gas turbine firing at maximum load with HRSG duct burner firing. The third mode includes gas turbine firing at maximum load with HRSG duct burner firing and steam injection power augmentation at the gas turbine combustors.

Under the Westinghouse turbine design, steam injection power augmentation lowers the post-combustor flame temperature (allowing an

increased fuel use rate) and increases mass flow through the turbine blades, which in turn increases gas turbine peak generating capacity during periods of high ambient temperature.

- Combustion Gas Turbines and Heat Recovery Steam Generators (HRSGs)

  District BACT Guideline 89.2.1 specifies BACT 2 (achieved in practice) for CO for gas turbines with a rated heat input $\geq$ 23 MM BTU per hour as a CO emission concentration of 10 ppmvd @ 15% O_2. BACT 1 (technologically feasible/cost-effective) is specified as a CO emission concentration of < 6 ppmvd @ 15% O_2. Both BACT specifications do not specify gas turbine/HRSG operating mode. It should be noted that BACT Guideline 89.2.1 is currently being revised to reflect recently permitted gas turbine facilities.

  The Los Medanos Energy Center will be subject to a CO emission concentration limit of 6 ppmvd @ 15% O_2 during all operating modes except for gas turbine start-up and shutdown. This limit applies to the combined exhaust from the gas turbine and HRSG and is predicated upon the use of an oxidation catalyst. This satisfies BACT 1 as discussed above.

Top-Down BACT Analysis

In response to comments from EPA Region 9, the following "top-down" BACT analysis for CO has been prepared in accordance with EPA's 1990 Draft New Source Review Workshop Manual.

Available Control Options and Technical Feasibility

The CO control options that have been cited for the proposed combined-cycle gas turbines at MEC include $SCONO_x$, catalytic oxidation, and combustion control (DLN Combustors). Representatives of $SCONO_x$ provide performance guarantees of 90% by weight for CO for gas turbines equipped with conventional combustors. They have not extended the guarantee to gas turbines equipped with DLN combustors which produce extremely low CO emissions of < 10 ppmvd @ 15% O_2. Because the ability of $SCONO_x$ to control CO has not been demonstrated on a gas turbine comparable to those proposed for the Metcalf Energy Center and because EPA has not identified SCONOx as BACT for CO, $SCONO_x$ is deemed to be a technically infeasible control alternative for CO.

As discussed above, we are not aware of any operating gas turbine comparable to those proposed for the Los Medanos Energy Center (with or without an oxidation catalyst) that has achieved CO emission concentrations significantly less than 6 ppmvd over all operating modes and ambient conditions except

start-up and shutdown. Therefore, BACT for CO is deemed to be an emission limitation of 6 ppmvd @ 15% O_2, averaged over three hours.

The LMEC has agreed to a CO emission limit of 6 ppmvd @ 15% O_2, averaged over 3 hours, after abatement by the proposed oxidation catalyst. This emission limit is more stringent than the current District BACT 2 specification of 10 ppmvd @ 15% O_2, averaged over three hours and equivalent to the District BACT 1 and ARB BACT specification of 6 ppmvd @ 15% O_2, averaged over three hours.

Precursor Organic Compounds (POCs)

- Combustion Gas Turbines

  Currently, District BACT Guideline 89.2.1 specifies BACT 2 (achieved in practice) for POC for gas turbines with a heat input rating $\geq$ 23 MM BTU per hour as 50% reduction by weight which is typically achieved through the use of an oxidation catalyst. BACT 1 (technologically feasible/cost-effective) is listed as > 50% reduction by weight, typically achieved through the use of an oxidation catalyst. These determinations were based upon District application #8658 for the Crockett Cogeneration Facility (170 MW GE 7FA) and application 10962 for UCSF Central Utilities Plant (5 MW Solar Centaur Taurus). However, a BACT determination based solely upon a weight percent reduction is not effective since the resulting emission rate at the stack is dependent upon the inlet concentration which is not limited. Therefore, these BACT determinations are undergoing revisions and will be expressed as an emission concentration (or equivalent emission factor) at the stack. Crockett Cogeneration is permitted at a POC emission concentration of 6.5 ppmvd @ 15% O_2 or 0.0061 lb/MM BTU. The UCSF Central Utilities Plant is permitted at a POC emission limit of 0.01 lb/MM BTU. The results of 4 annual source tests of the gas turbine and HRSG duct burners at the Crockett Cogeneration Facility have not exceeded 1 ppmvd POC @ 15% O_2. Because the source tests provide only a "snapshot" of the operation of the turbine, they do not substantiate a BACT 2 (achived in practice) determination since the testing does not capture the entire operating range of the turbine. The Delta Energy Center established a BACT 1 (technologically feasible/cost-effective) determination for POC when it was recently permitted at a POC emission limit of 2 ppmvd @ 15% O_2.

  The applicant has agreed to a POC emission limitations of 3.43 pounds per hour and 0.0017 lb/MM BTU that are equivalent to an emission concentration of 1.36 ppmvd @ 15% O_2. Because this emission limitation is more stringent than the current BAAQMD BACT 1 determination and the current ARB BACT determination for POC of 2 ppmvd @ 15% O_2, averaged over 1 hour, as promulgated in their July 22, 1999 power plant siting guidance document, LMEC satisfies BACT for POC.

- Heat Recovery Steam Generators (HRSGs)

  The HRSG duct burners will be of dry, low-NO_x design, which minimizes incomplete combustion and the POC emission rate. The applicant has agreed to a combined POC emission concentration limit of 1.36 ppmvd @ 15% O_2 for simultaneous firing of the turbine and HRSG duct burners. This converts to an emission factor of 0.0017 lb/MM BTU and a mass emission rate of 3.43 pounds per hour. This is more stringent that the current ARB BACT determination of 2 ppmvd @ 15% O_2, averaged over 1 hour, as promulgated in their power plant siting guidance document that was adopted on July 22, 1999. This emission rate is also more stringent than the POC emission rate established for the recently permitted Delta Energy Center, which was approved by the EPA and ARB at its permitted rate of 2 ppmvd POC @ 15% O_2.

Sulfur Dioxide (SO_2)

- Combustion Gas Turbines

  District BACT Guideline 89.2.1 specifies BACT for SO_2 for gas turbines with a heat input rating $\geq$ 23 MM BTU per hour as the exclusive use of clean-burning natural gas. The proposed turbines will utilize natural gas exclusively, with a maximum sulfur content of 1.0 grains per 100 scf, which will result in minimal SO_2 emissions. This corresponds to an SO_2 emission factor of 0.00277 lb/MM BTU. The maximum natural gas sulfur content specification of 1.0 grains per 100 scf is deemed BACT for SO_2.

- Heat Recovery Steam Generators (HRSGs)

  As is the case of the Gas Turbines, BACT for SO_2 for the HRSG duct burners is deemed to be the exclusive use of clean-burning natural gas with an expected sulfur content of 1.0 grains per 100 scf. This corresponds to an SO_2 emission factor of 0.00277 lb/MM BTU.

Particulate Matter (PM_{10})

- Combustion Gas Turbines

  District BACT Guideline 89.2.1 specifies BACT for PM_{10} for gas turbines with a heat input rating $\geq$ 23 MM BTU per hour as the exclusive use of clean-burning natural gas. The proposed turbines will utilize natural gas exclusively, which will result in minimal direct PM_{10} emissions and minimal formation of secondary PM_{10} such as sulfates. Because the sulfur content of the natural gas will not exceed 1.0 grains per 100 scf, the sulfate particulate formation will be minimized.

- Heat Recovery Steam Generators (HRSGs)

  As is the case of the Gas Turbines, BACT for PM_{10} for the HRSG duct burners is deemed to be the exclusive use of clean-burning natural gas with a maximum sulfur content of 1.0 grains per 100 scf.

EMISSION OFFSET ANALYSIS

Table 24 Original Emission Offset Summary

	NO_x	CO	POC	PM_{10}	SO_2
Calculated Facility Emissions[a] (ton/yr)	154.8	488.1	97.61	121.91	34.02
Facility Permit Limits (ton/yr)	153.2	487.5	97.61	123.55	39.86
Offsets Required	Yes	No	Yes	Yes	No
Offset Ratio	1.15:1.0[b]	N/A	1.15:1.0[b]	1.0:1.0	N/A
Offsets Required (tons)	**176.18**	**0**	**112.25**	**123.55**	**0**
Offsets Surrendered (tons)	**176.18**	**0**	**112.25**	**98.13**	**101.68[c]**

[a]sum of S-1 CTG, S-2 HRSG, S-3 CTG, S-4 HRSG, and S-5 Auxiliary Boiler emissions

[b]pursuant to District Regulation 2-2-302, the applicant must provide emission offsets at a ratio of 1.15 to 1.0 since the proposed facility NO_x and POC emissions from permitted sources will each exceed 50 tons per year

[c]LMEC provided 101.68 tons of SO_2 offsets to offset the outstanding 25.87 tons of PM_{10} at a ratio of 4:1 pursuant to District Regulation 2-2-303.1

Table 25 Revised Emission Offset Summary

	NO_x	CO	POC	PM_{10}	SO_2
Calculated Facility Emissions[a] (ton/yr)	175.64	507.36	33.8	131.6	47.11
Facility Permit Limits (ton/yr)	175.7	506.4	33.9	131.6	47.11
Offsets Required	Yes	No	Yes	Yes	No
Offset Ratio	1.15:1.0[b]	N/A	1.0:1.0	1.0:1.0	N/A
Offsets Required (tons)	**202.06**	**0**	**33.9**	**131.6**	**0**
Offsets Surrendered (tons)	**176.18**	**0**	**112.25**	**98.13**	**101.68[c]**
Outstanding Offsets Req'd	**25.88**	**0**	**(78.35)[d]**	**8.05**	**0**
Banking Certificate 659	**0**	**0**	**0**	**0**	**30.4**
Banking Certificate 660	**39.55**	**0**	**0**	**0**	**5.92**

[a]sum of S-1 CTG, S-2 HRSG, S-3 CTG, S-4 HRSG, and S-5 Auxiliary Boiler emissions

[b]pursuant to District Regulation 2-2-302, the applicant must provide emission offsets at a ratio of 1.15 to 1.0 since the proposed facility NO_x emissions from permitted sources will exceed 50 tons per year

[c]LMEC provided 101.68 tons of SO_2 offsets to offset 25.87 tons of PM_{10} at a ratio of 4:1 pursuant to District Regulation 2-2-303.1

[d]POC offsets to be refunded to applicant based upon revised emission rates and permit condition limits

As indicated above, the outstanding PM_{10} offset quantity required is calculated to be 131.6 – 98.13 – 101.68/4 = 8.05 tons of PM_{10}. This outstanding balance will be offset with 32.2 tons of SO_2 offsets at a ratio of 4 to 1 which will come from banking certificates 659 and 660. These certificates are owned by Calpine Construction Finance Co, L.P. and were derived from banking certificate 629 which originated from the shutdown of an Owens-Brockway glass plant located in Antioch.

Because the POC emission rates and corresponding enforceable permit condition limits have been revised downward to conform with current BACT specifications, 78.35 tons per year of POC offsets will be refunded to the applicant pursuant to Regulation 2-2-422.

PSD IMPACT ANALYSIS

The applicant has performed a PSD impact analysis for the LMEC under the revised plant configuration and demonstrated through modeling that the project will not cause or contribute to an exceedance of any applicable ambient air quality standard. The impact analysis was reviewed and approved by Dr. Glen Long of the District Planning division. See attached summary (model2.doc) for further detail.

Short-Term Impact Analysis

Permit condition 23 currently limits gas turbine start-up emission rates in pounds per hour and in pounds per start-up. Calpine has requested the removal of the lb/hr limits and the revision of the lb/start-up limits to those given in Table 4. To insure that the short-term impacts of the gas turbine under start-up conditions do not cause or contribute to an exceedance of the 1-hour CO and NO_2 ambient air quality standards, Calpine modeled the short-term (1-hour average) impacts under the following operating scenario:

- One turbine in start-up mode
  (NO_x emission rate of 240 lb/hr and CO emission rate of 2,514 lb/hr)
- One turbine operating at baseload
- Auxiliary boiler operating at full load

Per CEC recommendations, the turbine stack characteristics corresponding to minimum load operation were used to approximate stack characteristics during a turbine start-up. The results of the modeling show that the short-term impacts during start-up will not cause or contribute to an exceedance of the 1-hour CO and 1-hour NO_2 ambient air quality standards. The short-term impact analysis submitted by Calpine was reviewed and approved by Dr. Glen Long of the District Planning division.

FEE SUMMARY

Source	Fee Schedule	Filing Fee	Initial Fee	Late Fee	Permit to Operate Fee	Source Sub-Total
S-2 HRSG #1 Duct Burner	C	$198.00	$16,800.00	$0.00	$100.00	$16,998.00
S-4 HRSG #2 Duct Burner	C	$198.00	$16,800.00	$0.00	$100.00	$16,998.00
S-5 Auxiliary Boiler	C	$198.00	$17,920.00	$0.00	$100.00	$18,118.00
					Grand Total	**$52,114.00**
					Amount Paid	**$52,114.00**
					Log Number	**24109**

STATEMENT OF COMPLIANCE

All statements of compliance made in the FDOC issued on June 10, 1999 remain in effect. Any changes to those statements resulting from the proposed modifications to the facility are described below.

The Los Medanos Energy Center will **not** be located within 1000 feet of the outer boundary of the nearest school and is therefore not subject to the public notification requirements of Regulation 2-1-412.

A revised PSD impact analysis was submitted by the applicant to assess the impact resulting from the modified Los Medanos Energy Center and the addition of the fire pump diesel engine. As discussed in the attached summary prepared by Dr. Glen Long of the District Planning Division, the modified LMEC will not cause or contribute to an exceedance of any applicable state or federal air quality standard.

A Toxics Risk Screening Analysis was performed for the gas turbines, auxiliary boiler, fire pump diesel engine, and cooling tower for the compounds listed in Tables 17 through 21. As discussed earlier, the chronic hazard index was determined to be less than 1.0 and the increased carcinogenic risk was determined to be less than one in one million, over a 70-year exposure. Therefore, the public health risk posed by the modified LMEC is not significant and is therefore acceptable pursuant to the District Toxic Risk Management Policy.

Pursuant to Regulation 2-2-405, this authority to construct was subject to a 30-day public comment period. A notice inviting written public comment was published in the Contra Costa Times on February 9, 2001. The public comment period closed on March 14, 2001. No comments were received by the District. Pursuant to Regulation 2-2-406, the information

submitted by the applicant, the District's analysis, and the APCO's preliminary decision to grant the authority to construct was made available for public inspection at District headquarters during this 30 day period.

PERMIT CONDITIONS

Condition #16676 shall be modified as shown below:

Pittsburg District Energy Facility
Permit Conditions

Definitions:

Clock Hour:	Any continuous 60-minute period beginning on the hour.
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours.
Year:	Any consecutive twelve-month period of time
Heat Input:	All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in BTU/scf.
Rolling 3-hour period:	Any three-hour period that begins on the hour and does not include start-up or shutdown periods.
Firing Hours:	Period of time during which fuel is flowing to a unit, measured in fifteen minute increments.
MM BTU:	million british thermal units
Gas Turbine Start-up Mode:	The lesser of the first 180 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 21(b) and 21(d).
Gas Turbine Shutdown Mode:	The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 21(a) through 21(f) until termination of fuel flow to the Gas Turbine.
Auxiliary Boiler Start-up:	The lesser of the first 120 minutes of continuous fuel flow to an Auxiliary Boiler after fuel flow is initiated; or the period of time from fuel flow initiation until the Boiler achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 27(b) and 27(d).
Auxiliary Boiler Shutdown:	The lesser of the 30 minute period immediately prior the termination of fuel flow to the Auxiliary Boiler; or the period of time from non-compliance with any requirement listed in Conditions 27(a) through 27(d) until termination of fuel flow to the auxiliary boiler.
Specified PAHs:	The polycyclic aromatic hydrocarbons listed below shall be considered to Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds.

Benzo[a]anthracene
Benzo[b]fluoranthene
Benzo[k]fluoranthene
Benzo[a]pyrene
Dibenzo[a,h]anthracene
Indeno[1,2,3-cd]pyrene

Corrected Concentration: The concentration of any pollutant (generally NO_x, CO, or NH_3) corrected to a standard stack gas oxygen concentration. For emission point P-1 (Gas Turbine S-1 and HRSG S-2) and emission point P-2 (Gas Turbine S-3 and HRSG S-4) the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis. For emission point P-3 (Auxiliary Boiler S-5), the standard stack gas oxygen concentration is 3% O_2 by volume on a dry basis.

Commissioning Activities: All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the PDEF construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, auxiliary boiler, and associated electrical delivery systems.

Commissioning Period: The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exhange.

Precursor Organic Compounds (POCs): Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates and ammonium carbonate

CEC CPM: California Energy Commission Compliance Program Manager

Conditions for the Commissioning Period

1. The owner/operator of the Los Medanos Energy Center (LMEC) shall minimize emissions of carbon monoxide and nitrogen oxides from S-1 & S-3 Gas Turbines, S-2 & S-4 Heat Recovery Steam Generators (HRSG), and S-5 Auxiliary Boiler to the maximum extent possible during the commissioning period. Conditions 1 through 13 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 14 through 51 shall apply after the commissioning period has ended.

2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the combustors of S-1 & S-3 Gas Turbines, S-2 & S-4 Heat Recovery Steam Generators, and S-5 Auxiliary Boiler shall be tuned to minimize the emissions of carbon monoxide and nitrogen oxides.

3. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, A-1 & A-3 SCR Systems and A-2 & A-4 Oxidation Catalysts shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators.

4. Coincident with the steady-state operation of A-1 & A-3 SCR Systems and A-2 & A-4 Oxidation Catalysts pursuant to conditions 3, 8, and 9, the Gas Turbines (S-1 & S-3) and the HRSGs (S-2 & S-4) shall comply with the NO_x and CO emission limitations specified in conditions 21(a) through 21(d).

5. The owner/operator of the LMEC shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-1 and S-3 Gas Turbines describing the procedures to be followed during the commissioning of the turbines, HRSGs, auxiliary boiler, and steam turbine. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-NO_x combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and NO_x continuous emission monitors, and any activities requiring the firing of S-1 and S-3 Gas Turbines and S-2 and S-4 HRSGs without abatement by the SCR Systems or oxidation catalysts.

6. During the commissioning period, the owner/operator of the LMEC shall demonstrate compliance with conditions 11 and 12 through the use of properly operated and maintained continuous emission monitors and recorders for the following parameters:

   firing hours
   fuel flow rates
   stack gas nitrogen oxide emission concentrations,
   stack gas carbon monoxide emission concentrations
   stack gas oxygen concentrations.

   The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for S-1 and S-3 Gas Turbines, S-2 and S-4 HRSGs, and S-5 Auxiliary Boiler. The owner/operator shall use District-approved methods to calculate heat input rates, nitrogen oxide mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request.

7. The District-approved continuous monitors specified in condition 6 shall be installed, calibrated, and operational prior to first firing of S-1 & S-3 Gas Turbines, S-2 & S-4 Heat Recovery Steam Generators, and S-5 Auxiliary Boiler. After first firing of the turbines and auxiliary boiler, the detection range of these continuous emission monitors shall be adjusted as necessary to accurately measure the resulting range of CO and NO_x emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

8. The total number of firing hours of S-1 Gas Turbine and S-2 Heat Recovery Steam Generator without abatement of nitrogen oxide and carbon monoxide emissions by A-1 SCR System and A-2 Oxidation Catalyst shall not exceed 250 hours during the commissioning period. Such operation of S-1 Gas Turbine and S-2 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without SCR and

   oxidation catalysts in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 250 firing hours without abatement shall expire.

9. The total number of firing hours of S-3 Gas Turbine and S-4 Heat Recovery Steam Generator without abatement of nitrogen oxide and carbon monoxide emissions by A-3 SCR System and A-4 Oxidation Catalyst shall not exceed 250 hours during the commissioning period. Such operation of S-3 Gas Turbine and S-4 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without SCR and oxidation catalysts in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 250 firing hours without abatement shall expire.

10. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM_{10}, and sulfur dioxide that are emitted by S-1, S-2, S-3, S-4, and S-5 during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in condition 32.

11. Combined pollutant emissions from S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators shall not exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of S-1 & S-3 Gas Turbines.

NO_x (as NO_2)	3,511 pounds per calendar day	616 pounds/hour
CO	10,848 pounds per calendar day	5,053.8 pounds/hour
POC (as CH_4)	720 pounds per calendar day	
PM_{10}	816 pounds per calendar day	
SO_2	268 pounds per calendar day	

12. Pollutant emissions from S-5 Auxiliary Boiler shall not exceed the following limits during the commissioning period. These emission limits shall include emissions that occur during S-5 Auxiliary Boiler start-ups.

NO_x (as NO_2)	268 pounds per calendar day	21 pounds per hour
CO	233.8 pounds per calendar day	14 pounds per hour
POC (as CH_4)	16 pounds per calendar day	
PM_{10}	60 pounds per calendar day	
SO_2	8 pounds per calendar day	

12. Prior to the end of the Commissioning Period, the Owner/Operator shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with condition 23. The source test shall determine NO_x, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. Twenty calendar days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.

Conditions for the Gas Turbines (S-1 & S-3) and the Heat Recovery Steam Generators (HRSGs) (S-2 & S-4).

14. The Gas Turbines (S-1 and S-3) and HRSGs (S-2 and S-4) shall be fired exclusively on natural gas . (BACT for SO_2 and PM_{10})

15. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) shall not exceed 2,225.1 MM BTU per hour, averaged over any rolling 3-hour period. (PSD for NO_x)

16. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) shall not exceed 50,738.4 MM BTU per calendar day. (PSD for PM_{10})

17. The combined cumulative heat input rate for both Gas Turbines (S-1 and S-3) and both HRSGs (S-2 and S-4) shall not exceed 34,010,400 MM BTU per year. (Offsets)

18. The HRSG duct burners shall not be fired unless its associated Gas Turbine is in operation. (BACT for NO_x, CO, POC)

19. The Gas Turbine (S-1) and HRSG (S-2) shall be abated by the properly operated and properly maintained Oxidizing Catalyst (A-2) and Selective Catalytic Reduction System (A-1), in series. (BACT for NO_x and CO)

20. The Gas Turbine (S-3) and HRSG (S-4) shall be abated by the properly operated and properly maintained Oxidizing Catalyst (A-4) and Selective Catalytic Reduction System (A-3), in series. (BACT for NO_x and CO)

21. The owner/operator of the Gas Turbines (S-1 and S-3) and HRSGs (S-2 and S-4) shall meet all of the requirements listed in (a) through (h) below, except during a Gas Turbine Start-up or a Gas Turbine Shutdown. (BACT, PSD, and Toxic Risk Management Policy)

    (a) Nitrogen oxide emissions at P-1 (the combined exhaust point for the S-1 Gas Turbine and the S-2 HRSG after control by the A-1 SCR System and A-2 Oxidation Catalyst) shall not exceed 20.0 pounds per hour, calculated as NO_2, nor 0.009 lbs/MM BTU of natural gas fired. Nitrogen oxide emissions at P-2 (the combined exhaust point for the S-3 Gas Turbine and the S-4 HRSG after control by the A-3 SCR System and A-4 Oxidation Catalyst) shall not exceed 20.0 pounds per hour, calculated as NO_2, nor 0.009 lbs/MM BTU of natural gas fired. (PSD for NO_x)

    (b) The nitrogen oxide concentration at P-1 and P-2 each shall not exceed 2.5 ppmv, corrected to 15% O_2, on a dry basis, averaged over any 1-hour period. (BACT for NO_x)

    (c) Carbon monoxide emissions at P-1 and P-2 each shall not exceed 29.2 pounds per hour, or 0.0132 lb/MM BTU of natural gas fired. (PSD for CO)

    (d) The carbon monoxide concentration at P-1 and P-2 each shall not exceed 6 ppmv, corrected to 15% O_2, on a dry basis, averaged over any rolling 3-hour period. (BACT for CO)

    (e) Ammonia (NH_3) emissions at P-1 and P-2 each shall not exceed 10 ppmv, corrected to 15% O_2, on a dry basis, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous records of the ammonia injection rate to A-1 and A-3 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-1 and A-3 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1 and P-2 shall be determined in accordance with permit condition 38. (TRMP for NH_3)

    (f) Precursor organic compound (POC) emissions at P-1 and P-2 each shall not exceed 3.8 pounds per hour, nor 0.0017 lb/MM BTU of natural gas fired. (BACT)

    (g) Sulfur dioxide (SO_2) mass emissions at P-1 and P-2 each shall not exceed 6.2 pounds per hour or 0.00277 lb/MM BTU of natural gas fired. (BACT)

    (h) Particulate matter (PM_{10}) mass emissions at P-1 and P-2 each shall not exceed 16.3 pounds per hour or 0.0073 lb/MM BTU of natural gas fired. (BACT)

22. The following conditions shall apply to NO_x emissions resulting from or attributable to transient, non-steady state operating conditions. (BACT for NO_x)

    (a) CEM NO_x emission concentration data points that result from or are attributable to transient, non-steady state conditions shall not be subject to the emission limitations specified in Condition 21(b). In any event, the nitrogen oxide concentration at P-1 and P-2 each shall not exceed 2.5 ppmv, corrected to 15% O_2, on a dry basis, averaged over any rolling 3-hour period. All CEM NO_x emission concentration data points shall be utilized when determining compliance with this emission concentration limit.

(b) The emission limitation specified in Condition 22(a) shall be valid for a period not to exceed 24 months from the end of the Commissioning period. At such time the emission limitation specified in Condition 21(b) shall apply for all operating conditions except gas turbine start-up and shutdown periods, unless specific transient, non-steady state conditions are identified pursuant to conditions 22(f) and (g).

(c) Definitions

A transient, non-steady state condition shall occur when the following conditions exist:

1) One or more equipment design features is unable to support rapid changes in operation and respond to and adjust all operating parameters required to maintain the steady-state NOx emission limit specified in condition 21(b). A change in operation shall be limited to one or more of the following: a change in combustion turbine load greater than 6 MW/minute; a change in SCR system space velocity greater than 50 ft/minute; initiation/shutdown of the evaporative cooler; initiation/shutdown of the duct burners; and a change in duct burner firing rate greater than 600,000 BTU/minute. Additional non-steady state conditions may be defined based upon operational experience and mutual written agreement of the owner/operator, the District, ARB, and EPA.
2) For purposed of this condition, transient, non-steady state conditions shall not include the start-up and shutdown periods that are the subject of condition 23.

(d) The owner/operator shall maintain continuous emission monitor (CEM) data and complete records of plant emission performance under transient, non-steady state conditions. The owner/operator shall record the NO_x emission concentration and document the cause of each transient, non-steady state condition with operational data. A description of the specific parameters that will be monitored to document a transient, non-steady state condition shall be submitted to the District, ARB, and EPA for approval at least 60 days prior to the end of the Commissioning period.

(e) Within 6 months of the end of the Commissioning period, the owner/operator shall compile and submit source test data, using a District-approved test protocol, to assess NO_x emissions under transient, non-steady state conditions. A source test protocol shall be submitted to the District and EPA for approval at least 60 days prior to testing.

(f) Within 15 months of the end of the Commissioning period, the owner/operator shall submit a plan to the District and EPA designed to minimize emissions during transient, non-steady state conditions. The plan shall identify reasonable measures that will be taken to control NO_x emissions. This plan shall be based upon the CEM and source test data developed in accordance with condition 22(e) and actual operating experience during the preceding months of plant operation. The plan shall be developed in consultation with the manufacturers selected for the gas turbine, HRSG, control systems, and air pollution control units. After the plan has been approved by the District and EPA, the owner/operator shall use the procedures described in the plan to minimize NO_x emissions during transient, non-steady state conditions.

(g) On a semi-annual basis, for the first 24 months after the end of the Commissioning period, the owner/operator shall provide a report to the District with continuous emission monitoring and source test data developed in accordance with this condition. The District will use the data and related operating experience to establish maximum NO_x emission limits for transient, non-steady state conditions for the following 6 month period. The District will consider operations at similar (e.g., electrical generation and fuel-type) facilities in determining the revised emission limits. In no event shall the NO_x emission limits established pursuant to section (g) be less than the NO_x emission limits specified in Condition 21(b). In addition, if appropriate, on a semi-annual basis the district will use all data and related operating experience to establish (i) a revised definition of transient, non-steady state conditions to which the NO_x emission limitations established pursuant to this section (g) shall apply, and (ii) the data collection and recordkeeping requirements that the owner/operator shall use to document the occurrence of transient non-steady state conditions.

23. The pollutant emission rates from each of the Gas Turbines (S-1 and S-3) during a start-up or shutdown shall not exceed the limits established below. (PSD)

	Start-Up (lb/start-up)	Shutdown (lb/shutdown)
Oxides of Nitrogen (as NO_2)	240	20
Carbon Monoxide (CO)	2,514	44.1
Precursor Organic Compounds (as CH_4)	48	8

Within three months of the end of the Commissioning period, the owner/operator shall submit a plan designed to minimize emissions during the transient conditions encountered during gas turbine start-ups and shutdowns. This plan shall indicate what steps will be taken to start controlling NO_x emissions as soon as feasible, including when ammonia can be fed to the SCR system without producing ammonia slip in excess of 10 ppmvd @ 15% O_2. This plan shall be based upon the experience gathered from the source tests performed per condition #13 and actual operating experience gained during the first six-months of operation. This plan shall also be developed in consultation with the manufacturers of the gas turbines, HRSGs, control systems, and air pollution control units. This plan shall be submitted to the CEC CPM for approval. After the plan has been approved, the owner/operator shall use the procedures included in the plan to minimize NO_x emissions during gas turbine start-ups and shutdowns. Within 24 months of the end of the Commissioning period, the owner/operator shall submit a report to the District and the CEC CPM that establishes reasonable maximum hourly mass emission rates for start-up and shutdown conditions. The revised mass emission rates shall be based upon source test and continuous emission monitoring data. Pending approval of the District and the CEC

CPM, these revised mass emission rates shall be established as new emission limitations that will supersede the limits included in this condition.

24. The Gas Turbines (S-1 and S-3) shall not be in start-up mode simultaneously. (PSD)

Conditions for the Auxiliary Boiler (S-5)

25. The Auxiliary Boiler (S-5) shall be fired exclusively on natural gas. (BACT for SO_2 and PM_{10})

26. The heat input rate to the Auxiliary Boiler (S-5) shall not exceed 320 million BTU per hour, averaged over any rolling 3-hour period. (Cumulative Increase)

27. The cumulative heat input rate to the Auxiliary Boiler (S-5) shall not exceed 480,000 million BTU per year. (Cumulative Increase)

28. The owner/operator of the Auxiliary Boiler (S-5) shall meet all of the requirements listed in (a) through (g) below, except during an Auxiliary Boiler Start-up or an Auxiliary Boiler Shutdown. (BACT, PSD)

    (a) Nitrogen oxide emissions at P-3 (the exhaust point for the Auxiliary Boiler) shall not exceed 3.5 pounds per hour, calculated as NO_2. (PSD for NO_x)

    (b) The nitrogen oxide concentration at P-3 shall not exceed 9.0 ppmv, measured as NO_x, corrected to 3% O_2, on a dry basis, averaged over any rolling 3-hour period. (BACT for NO_x)

    (c) Carbon monoxide emissions at P-3 shall not exceed 11.8 pounds per hour. (PSD for CO)

    (d) The carbon monoxide concentration at P-3 shall not exceed 50 ppmv, corrected to 3% O_2, on a dry basis, averaged over any rolling 3-hour period. (BACT for CO)

    (e) Precursor organic compound (POC) emissions at P-3 shall not exceed 1.7 pounds per hour. (cumulative increase)

    (f) Sulfur dioxide (SO_2) mass emissions at P-3 shall not exceed 0.5 pounds per hour. (cumulative increase)

    (g) Particulate matter (PM_{10}) mass emissions at P-3 shall not exceed 1.6 pounds per hour. (cumulative increase)

    (h) Ammonia (NH_3) emissions at P-3 shall not exceed 10 ppmv, corrected to 3% O_2, on a dry basis, averaged over any rolling 3-hour period. This ammonia concentration shall be verified by the continuous recording of the ammonia injection rate at the A-5 SCR System. The correlation between the auxiliary boiler heat input rate, A-5 SCR System

ammonia injection rate, and corresponding ammonia emission concentration at P-3 shall be determined in accordance with permit condition 38. (TRMP)

29. The Auxiliary Boiler (S-5), its burners, combustion chamber, and exhaust system shall be designed and constructed so that the boiler can be retrofitted with an oxidizing catalyst in the event the Auxiliary Boiler cannot consistently comply with the emission limitations specified in condition 28. (BACT for CO)

Conditions for All Sources
(S-1, S-2, S-3, S-4, and S-5)

30. The combined heat input rate to the Gas Turbines (S-1 and S-3), HRSGs (S-2 and S-4), and Auxiliary Boiler (S-5) shall not exceed 109,157 million BTU per calendar day. (PSD, CEC Offsets)

31. The cumulative heat input rate to the Gas Turbines (S-1 and S-3), HRSGs (S-2 and S-4), and Auxiliary Boiler (S-5) combined shall not exceed 34,490,400 million BTU per year. (Offsets)

32. Total combined emissions from the Gas Turbines, HRSGs, and Auxiliary Boiler (S-1, S-2, S-3, S-4, and S-5), including emissions generated during Gas Turbine Start-ups, Gas Turbine Shutdowns, Auxiliary Boiler Start-ups, and Auxiliary Boiler Shutdowns, shall not exceed the following limits during any calendar day:

    (a) 1,342 pounds of NO_x (as NO_2) per day (CEQA)
    (b) 6,445 pounds of CO per day (PSD)
    (c) 271.3 pounds of POC (as CH_4) per day (CEQA)
    (d) 742 pounds of PM_{10} per day (PSD)
    (e) 282.6 pounds of SO_2 per day (BACT)

    ~~During days with two cold start-ups (the Gas Turbines have been out of service for more than 72 hours) daily combined NO_x emissions (as NO_2) from the Gas Turbines, HRSGs, and Auxiliary Boiler (S-1, S-2, S-3, S-4, and S-5) shall not exceed 1330 pounds per day. The number of days where the combined NO_x emissions are greater 1190 lb/day and less than 1330 lb/day shall be limited to 10 per consecutive twelve month period.~~

33. Cumulative emissions from the Gas Turbines, HRSGs, and the Auxiliary Boiler combined (S-1, S-2, S-3, S-4, and S-5), including emissions generated during Gas Turbine Start-ups, and Gas Turbine Shutdowns, shall not exceed the following limits during any consecutive twelve-month period:

    (a) 175.7 tons of NO_x (as NO_2) per year (Offsets, PSD)
    (b) 506.4 tons of CO per year (Cumulative Increase)
    (c) 33.9 tons of POC (as CH_4) per year (Offsets)
    (d) 131.6 tons of PM_{10} per year (Offsets, PSD)
    (e) 47.11 tons of SO_2 per year (Cumulative Increase)

34. The maximum projected annual toxic air contaminant emissions from the Gas Turbines, HRSGs, and the Auxiliary Boiler combined (S-1, S-2, S-3, S-4, and S-5) shall not exceed the following limits:

    (a) 3,817 pounds of formaldehyde per year
    (b) 460.9 pounds of benzene per year
    (c) 78.5 pounds of Specified polycyclic aromatic hydrocarbons (PAHs) per year

    unless the owner/operator meets the requirements of (d), (e), and (f) below:

    (d) The owner/operator shall perform a health risk assessment using the emission rates determined by source test and the most current Bay Area Air Quality Management District (District) approved procedures and unit risk factors in effect at the time of the analysis. The calculated excess cancer risk shall not exceed 1.0 in one million.

    (e) The owner/operator shall perform a second risk analysis using the emission rates determined by source test and the procedures and unit risk factors in effect when the Determination of Compliance was issued. The calculated excess cancer risk shall not exceed 1.0 in one million.

    (f) Both of these risk analyses shall be submitted to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will satisfy the conditions stated in parts (d) and (e) above, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

35. The owner/operator shall demonstrate compliance with conditions 15 through 18, 21(a) through 21(d), 23, 24, 26, 28(a) through 28(d), 32(a), 32(b), 33(a), and 33(b) by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up and Shutdown periods) for all of the following parameters:

    (a) Firing Hours and Fuel Flow Rates for each of the following sources: S-1 and S-2 combined, S-3 and S-4 combined, and S-5.
    (b) Oxygen (O_2) Concentrations, Nitrogen Oxides (NO_x) Concentrations, and Carbon Monoxide (CO) Concentrations at each of the following exhaust points: P-1, P-2 and P-3.
    (c) Ammonia injection rate at A-1 and A-3 SCR Systems

    The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total Firing Hours, the average hourly Fuel Flow Rates, and pollutant emission concentrations.

    The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

(c) Heat Input Rate for each of the following sources: S-1 and S-2 combined, S-3 and S-4 combined, and S-5.

(d) Corrected NO_x concentrations, NO_x mass emissions (as NO_2), corrected CO concentrations, and CO mass emissions at each of the following exhaust points: P-1, P-2, and P-3.

For each source, source grouping, or exhaust point, the owner/operator shall record the parameters specified in conditions 35(c) and 35(d) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

(e) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.

(f) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined, the Auxiliary Boiler, and all five sources (S-1, S-2, S-3, S-4, and S-5) combined.

(g) the average NO_x mass emissions (as NO_2), CO mass emissions, and corrected NO_x and CO emission concentrations for every clock hour and for every rolling 3-hour period.

(h) on an hourly basis, the cumulative total NO_x mass emissions (as NO_2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, the Auxiliary Boiler, and all five sources (S-1, S-2, S-3, S-4, and S-5) combined.

(i) For each calendar day, the average hourly Heat Input Rates, Corrected NO_x emission concentrations, NO_x mass emissions (as NO_2), corrected CO emission concentrations, and CO mass emissions for each Gas Turbine and associated HRSG combined and the Auxiliary Boiler.

(j) on a daily basis, the cumulative total NO_x mass emissions (as NO_2) and cumulative total CO mass emissions, for each calendar year for all five sources (S-1, S-2, S-3, S-4, and S-5) combined.

(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

36. To demonstrate compliance with conditions 23, 32(c) through 32(e), and 33(c) through 33(e), the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter (PM_{10}) mass emissions (including condensable particulate matter), and Sulfur Dioxide (SO_2) mass emissions from each power train and the auxiliary boiler. The owner/operator shall use the actual Heat Input Rates calculated pursuant to condition 35, actual Gas Turbine Start-up Times, actual Gas Turbine Shutdown Times, and CEC and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

(a) For each calendar day, POC, PM_{10}, and SO_2 Emissions shall be summarized for: each power train (Gas Turbine and its respective HRSG combined); the Auxiliary Boiler; and the five sources (S-1, S-2, S-3, S-4, and S-5) combined.

(b) on a daily basis, the cumulative total POC, PM_{10}, and SO_2 mass emissions, for each year for all five sources (S-1, S-2, S-3, S-4, and S-5) combined.

(Offsets, PSD, Cumulative Increase)

37. To demonstrate compliance with Condition 34, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAH's. Maximum projected annual emissions shall be calculated using the maximum Heat Input Rate of 39,390,400 MM BTU/year and the highest emission factor (pounds of pollutant per MM BTU of Heat Input) determined by any source test at the Gas Turbine, HRSG, or Auxiliary Boiler. (TRMP)

38. Within 60 days of start-up of the LMEC, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 and P-3 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 21(e) and 28(h). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-1 or A-3 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-1 or P-2 and the correlation between the heat input rate of the auxiliary boiler, A-5 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-3. The source test shall be conducted over the expected operating range of the turbine (at a minimum, 60%, 80%, and 100% load) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. Continuing compliance with condition 21(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (TRMP)

39. Within 60 days of start-up of the LMEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1 and P-2 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load to determine compliance with Conditions 21(a), (b), (c), (d), (f), (g), & (h) and while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 21(c), (d), & (f) and to verify the accuracy of the continuous emission monitors required in condition 35. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and emissions, methane, ethane, and particulate matter (PM_{10}) emissions including condensable particulate matter. Upon request of the owner/operator, the District may waive the source test requirement for sulfur dioxide and/or particulate matter during any year if the District determines that prior source test results demonstrate that the sources have achieved compliance by a sufficiently wide margin. (BACT, offsets)

40. Within 60 days of start-up of the LMEC and on an annual basis thereafter, the owner/operator shall conduct a District approved source test on exhaust point P-3 while the Auxiliary Boiler (S-5) is operating at maximum allowable operating rates to determine compliance with the emission limitations of Condition 28(a) through 28(g) and to verify the accuracy of the continuous emission monitors required in condition 35. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and emissions, and particulate matter (PM_{10}) emissions including condensable particulate matter. (BACT, offsets)

41. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM_{10} emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 30 days of conducting the tests. (BACT)

42. Within 60 days of start-up of the LMEC and on an biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 34. Unless the requirements of condition 42(b) have been met, the owner/operator shall determine the formaldehyde, benzene, and Specified PAH emission rates (in pounds/MM BTU). If any of the above pollutants are not detected (below the analytical detection limit), the emission concentration for that pollutant shall be deemed to be one half (50%) of the detection limit concentration. (TRMP)

    (a) The owner/operator shall calculate the maximum projected annual emission rate for each pollutant by multiplying the pollutant emission rate (in pounds/MM BTU; determined by source testing) by 34,490,400 MM BTU/year.

    (b) If three consecutive biennial source tests demonstrate that the emission rates calculated pursuant to part (a) for any of the compounds listed below are less than the annual emission rates shown, then the owner/operator may discontinue future testing for that pollutant:

Benzene	≤	221 pounds/year
Formaldehyde	≤	1,834 pounds/year
Specified PAH's	≤	38 pounds/year

    (TRMP)

43. The owner/operator shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)

44. The owner/operator shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emissions, monitor excesses, breakdowns, etc.), source test and analytical records, emission calculation records, records of plant upsets and related incidents. The

owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)

45. The owner/operator shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Not withstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)

46. The stack heights of the emission points P-1 and P-2 shall be at least 150 feet above mean sea level (approximately 138.8 feet above grade level at the stack base). The stack height of the

emission point P-3 shall be at least 100.6 feet above mean sea level (approximately 88.6 feet above grade level at the stack base). (PSD, TRMP)

47. The Owner/Operator of LMEC shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall be subject to BAAQMD review and approval.
(Regulation 1-501)

48. Within 180 days of the issuance of the Authority to Construct, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous monitors, sampling ports, platforms, and source tests required by Conditions 38, 39, 40, and 42. All source testing and monitoring shall be conducted in accordance with the BAAQMD Manual of Procedures. (Regulation 1-501)

49. Prior to the issuance of the BAAQMD Authority to Construct for the Los Medanos Energy Center, the Owner/Operator shall demonstrate that valid emission reduction credits in the amount of 25.88 tons/year of Nitrogen Oxides, and 8.05 tons/year of PM_{10} or equivalent as defined by District Regulations 2-2-302.1, 2-2-302.2, and 2-2-303.1 are under their control through option to purchase contracts or equivalent binding legal documents. (Offsets)

50. Prior to the issuance of the BAAQMD Permit to Operate for the Pittsburg District Energy Facility, the Owner/Operator shall provide emission reduction credits in the amount of 25.88 tons/year of Nitrogen Oxides, and 8.05 tons/year of PM_{10} or equivalent as defined by District Regulations 2-2-302.1, 2-2-302.2, and 2-2-303.1. (Offsets)

51. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.1, the owner/operator of LMEC shall submit an application to the District for a Federal (Title V) Operating Permit within 12 months of the date of issuance of the BAAQMD Permit to Operate for the LMEC. (Regulation 2-6-404.1)

52. The heat input to the fire pump diesel engine resulting from maintenance and testing activities shall not exceed 211 MM BTU totaled over any consecutive twelve month period. (TRMP)

RECOMMENDATION

- Issue a **modifed, conditional Authority to Construct** for the following sources:

S-1 Combustion Gas Turbine #1, General Electric Frame 7FA Model PG 7241 or equivalent; 1,925.1 MM BTU per hour (HHV), equipped with dry low-NO_x Combustors, abated by A-1 Selective Catalytic Reduction System and A-2 Oxidation Catalyst

S-2 Heat Recovery Steam Generator #1, equipped with dry low-NO_x Duct Burners, 333 MM BTU per hour (HHV), abated by A-1 Selective Catalytic Reduction System and A-2 Oxidation Catalyst

S-3 Combustion Gas Turbine #2, General Electric Frame 7FA Model PG 7241 or equivalent; 1,925.1 MM BTU per hour (HHV), equipped with dry low-NO_x Combustors, abated by A-3 Selective Catalytic Reduction System and A-4 Oxidation Catalyst

S-4 Heat Recovery Steam Generator #2, equipped with dry low-NO_x Duct Burners, 333 MM BTU per hour (HHV), abated by A-3 Selective Catalytic Reduction System and A-4 Oxidation Catalyst

S-5 Auxiliary Steam Boiler, 320 MM BTU per hour (HHV), equipped with low-NO_x burners, abated by A-5 Selective Catalytic Reduction System

- Issue a **letter of exemption** for the following equipment:

Fire Pump Diesel Engine, Cummins Model 6CTA8.3-F3; 300 bhp, 2.11 MM BTU/hr heat input

(exempt per Regulation 2-1-114.2.3.1)

Emergency Generator, Caterpillar Model G3512 90 LE, natural gas fired, 600 KW, 6.44 MM BTUhr heat input

(exempt per Regulation 2-1-114.2.3.1)

8-Cell Cooling Tower

(exempt per Regulation 2-1-128.4)

- Issue a **banking certificate** in the amount of **53.25 tons per year of POC** emission reduction credits to Calpine Corporation.
- Issue a **banking certificate** in the amount of **25.1 tons per year of POC** emission reduction credits to Calpine Construction Finance Company, L.P.

By: _____ _____

Air Quality Engineer II **Date**