APPENDIX C

CTG OPERATIONAL EMISSION CALCULATIONS AND EVALUATION OF LOCALIZED AIR QUALITY IMPACTS

This appendix presents the calculations of CTG emissions resulting from the currently proposed project modifications. It describes calculation of emissions during CTG cold startups, non-cold startups and shutdowns. It also describes the revised calculation of SO_x and PM10 emissions during normal CTG operations. Additionally, Mitigation Measure AQ-5 in the January 2002 Final EIR required the use of diesel fuel with a sulfur content of 15 parts per million by weight (ppmw) or less. However, the calculation of mitigated SO_x emissions during diesel-fuel readiness testing were not provided in the January 2002 Final EIR. Therefore, this appendix also describes the calculation of this emission rate. The calculation of CO, NO_x, and VOC emissions during normal CTG operation as well emissions of CO, NO_x, VOC and PM10 during diesel-fuel readiness testing are the same as presented in Appendix C to the January 2002 Final EIR.

This appendix then presents estimated peak daily CTG emissions and atmospheric dispersion modeling used to evaluate localized air quality impacts.

C.1 COLD STARTUP EMISSIONS

Peak hourly and total NO_x emissions are estimated to be 225 lb/hr and 600 lb/startup, respectively, based on actual operating data from the facility.

Uncontrolled CO emissions are anticipated to be 100 lb/hr during a cold startup. The CO oxidation catalyst operating temperature is anticipated to be reached after the first hour of startup. The CO control factor after the first hour is based on the manufacturers' guaranteed exhaust concentration of 6 parts per million by volume dry (ppmvd) at full load with a CO input to the oxidation catalyst of 9 ppmvd. Therefore, the controlled CO emission rate during the last five hours of a cold startup was assumed to be 100 lb/hr x (6 ppmvd / 9 ppmvd) = 66.67 lb/hr. Total CO emissions a cold startup would then be 100 lb for the first hour + 5 hrs x 66.67 lb/hr = 433.35 lb/startup.

VOC emissions are estimated to be 3.47 lb/hr throughout a cold startup. Therefore, total VOC emissions would be 6 hrs x 3.47 lb/hr = 20.82 lb/startup.

SO_x emissions were calculated using an emission factor of 0.60 lb/million standard cubic feet (lb/MMscf) developed by SCAQMD (2003). After the SCR catalyst reaches operating temperature, which is anticipated to occur after the first two hours of a cold startup, 60 percent of the SO_x produced from fuel combustion is anticipated to be oxidized to SO_3 in the SCR system. Thus, 40 percent of the SO_x produced would remain as SO_x, so the emission factor during the third through sixth hours of a cold startup would be 40 percent x 0.60 lb/MMscf / 100 = 0.24 lb/MMscf.

PM10 emissions produced directly by fuel combustion were calculated using an emission factor of 0.0066 pounds per million British Thermal Units (lb/MMBtu) of heat input from Table 3.1-2a of Section 3.1, "Stationary Gas Turbines," of the U.S. Environmental Protection Agency's Compilation of Air Pollutant Emission Factors (AP-42, USEPA 2000). This emission factor is converted to emissions per million standard cubic feet (MMscf) of fuel by multiplying by the 1,050 Btu/scf higher heating value (HHV) of the natural gas: 0.0066 lb/MMBtu x 1,050 Btu/scf = 6.93 lb/MMscf.

In addition to PM10 emissions produced directly by fuel combustion, SO_3 produced by oxidation of SO_x in the SCR system will react with water vapor to form sulfuric acid, which will then react with ammonia "slip" in the exhaust when ammonia injection is occurring to produce particulate $(NH_4)_2SO_4$. Ammonia injection is anticipated to occur during the last four hours of a cold startup. During this period, the additional PM10 emissions caused by $(NH_4)_2SO_4$ formation is equal to 0.60 lb SO_x/MMscf x 60 percent oxidized / 100 x 132 lb $(NH_4)_2SO_4$/lb-mole / 64 lb SO_2/lb-mole = 0.742 lb/MMscf. Therefore, the total PM10 emission factor when the SCR system is operating and ammonia injection is occurring is 6.93 lb/MMscf + 0.742 lb/MMscf = 7.67 lb/MMscf.

Table C-1 shows fuel use during each hour of a cold startup, estimated from manufacturers' information, and the resulting SO_x and PM10 emissions.

Table C-1
SO_x and PM10 Emissions During Cold Startup

Hour	Fuel Use (MMscf)	SO_x Emission Factor (lb/MMscf)	PM10 Emission Factor (lb/MMscf)	SO_x Emissions (lb/hr)	PM10 Emissions (lb/hr)
1	0.3740	0.60	6.93	0.22	2.59
2	0.5329	0.60	6.93	0.32	3.69
3	0.5329	0.24	7.67	0.13	4.09
4	0.5329	0.24	7.67	0.13	4.09
5	0.8210	0.24	7.67	0.20	6.30
6	1.4140	0.24	7.67	0.34	10.85
Total (lb/startup)				**1.34**	**31.61**

C.2 NON-COLD STARTUP EMISSIONS

Peak hourly and total NO_x emissions are estimated to be 170 lb/hr and 300 lb/startup, respectively, based on actual operating data from the facility.

Uncontrolled CO emissions during a non-cold startup are anticipated to be the same as during a cold startup (100 lb/hr). The CO oxidation catalyst is anticipated to be operational during the second and third hours. Therefore, total CO emissions during a non-cold startup are anticipated to be 100 lb/hr + 2 hrs x 66.67 lb/hr = 233.34 lb/startup.

Hourly VOC emissions during a non-cold startup are anticipated to be the same as during a cold startup (3.47 lb/hr). Therefore, total VOC emissions during a non-cold startup are anticipated to be 3 hrs x 3.47 lb/hr = 10.41 lb.

SO_x and PM10 emission factors during a non-cold startup are anticipated to be the same as during a cold startup, with the SCR system operational during the third hour. Table C-2 shows fuel use during each hour of a cold startup, estimated from manufacturers' information, and the resulting SO_x and PM10 emissions.

Table C-2
SO_x and PM10 Emissions During Non-Cold Startup

Hour	Fuel Use (MMscf)	SO_x Emission Factor (lb/MMscf)	PM10 Emission Factor (lb/MMscf)	SO_x Emissions (lb/hr)	PM10 Emissions (lb/hr)
1	0.4535	0.60	6.93	0.27	3.14
2	0.5329	0.60	6.93	0.32	3.69
3	1.1175	0.24	7.67	0.27	8.57
			Total (lb/startup)	**0.86**	**15.41**

C.3 SHUTDOWN EMISSIONS

NO_x emissions are based on actual operating data. CO emissions during CTG shutdown were estimated from anticipated fuel use and control device efficiency for each five-minute interval during the shutdown process. VOC emissions during the five-minute intervals were estimated based on fuel use and anticipated exhaust gas concentration. SO_x and PM10 emissions during the five-minute intervals were estimated from fuel use. Attachment C.1 provides the details of the CO, VOC, SO_x and PM10 emission calculations during CTG shutdown.

C.4 SO_X AND PM10 EMISSIONS DURING NORMAL OPERATIONS

SO_x emissions during normal operations were calculated using the emission factor of 0.60 lb/MMscf. When the duct burners are operational, 65 percent of the SO_x produced from fuel combustion is anticipated to be oxidized to SO_3 in the SCR system. Thus, 35 percent of the SO_x produced would remain as SO_x, so the emission factor during normal operation with duct burners operating would be 35 percent x 0.60 lb/MMscf / 100 = 0.21 lb/MMscf.

PM10 emissions produced directly by fuel combustion during normal operations were calculated using the emission factor of 6.93 lb/MMscf. The additional PM10 emissions caused by $(NH_4)_2SO_4$ formation is equal to 0.60 lb SO_x/MMscf x 65 percent oxidized / 100 x 132 lb $(NH_4)_2SO_4$/lb-mole / 64 lb SO_2/lb-mole = 0.804 lb/MMscf. Therefore, the total PM10 emission factor during normal operations with duct burners operating is 6.93 lb/MMscf + 0.804 lb/MMscf = 7.73 lb/MMscf.

Fuel use during normal operations with duct burners operating is anticipated to be 1.957 MMscf/hr. SO_x emissions are therefore estimated to be 0.21 lb/MMscf x 1.957 MMscf/hr = 0.41 lb/hr. PM10 emissions are estimated to be 7.73 lb/MMscf x 1.957 MMscf/hr = 15.14 lb/hr.

C.5 SO_X EMISSIONS DURING DIESEL FUEL READINESS TESTING

SO_x emissions produced by diesel fuel combustion were calculated using an emission factor of 1.01S lb/MMBtu from Table 3.1-2a of Section 3.1, "Stationary Gas Turbines," of AP-42, where S is the weight percent sulfur in the fuel. The resulting emission factor for 15 ppmw diesel fuel is 1.01 x 15 ppwm x 1 percent/10,000 ppmw = 0.0015 lb/MMBtu. This emission factor is converted to emissions per thousand gallons (Mgal) of fuel by multiplying by the 139,000 MMBtu/Mgal higher heating value of the diesel fuel: 0.0015 lb/MMBtu x 139 MMBtu/Mgal = 0.21 lb/Mgal.

Diesel fuel use during each one-hour readiness test is anticipated to be 13.902 Mgal. Therefore, SO_x emissions during a one-hour diesel-fuel readiness would be 0.21 lb/Mgal x 13.902 Mgal = 2.92 lb/test.

C.6 PEAK DAILY CTG EMISSIONS

Peak hourly and total emissions during cold and non-cold startups of one CTG are listed in Table C-3 along with startup emissions from the January 2002 FEIR. Emissions during shutdown of one CTG are listed in Table C-4, and emissions during normal operations and diesel-fuel readiness testing are listed in Table C-5. As seen in Table C-5, the lower SO_x emission factor and the reduction in SO_x emissions from oxidation in the SCR system used in the current analysis reduced estimated SO_x emissions during normal operations from those estimated in the January 2002 FEIR. PM10 emissions are also slightly lower because of the use of the lower SO_x emission factor and a resulting decrease in oxidized SO_x emissions converted to PM10.

Table C-3
Emissions During One CTG Startup

	Cold Startup		Non-Cold Startup		Startup in FEIR[a]	
Pollutant	Maximum Hourly (lb/hr)	Total During One CTG Startup[b] (lb/startup)	Maximum Hourly (lb/hr)	Total During One CTG Startup[c] (lb/startup)	Maximum Hourly (lb/hr)	Total During One CTG Startup[d] (lb/startup)
CO	100.00	433.35	100.00	233.34	100	326.2
NO_x	225.00	600.00	170.00	300.00	20	78.0
VOC	3.47	20.82	3.47	10.41	4.12	14.6
SO_x	0.34	1.34	0.32	0.86	2.49	4.8
PM10	10.85	31.61	8.57	15.41	14.7	25.8

[a] Source: Table 4.2-6 from January 2002 FEIR; No changes due to October 2003 Addendum
[b] Cold startup duration is six hours
[c] Non-cold startup duration is three hours
[d] Startup duration is four hours

Table C-4
Emissions During One CTG Shutdown

Pollutant	Total During Shutdown[a] (lb/shutdown)
CO	7.38
NO_x	22.1
VOC	1.24
SO_x	0.11
PM10	3.50
[a] Shutdown duration is 0.5 hour	

Table C-5
Emissions During One CTG Normal Operation and Diesel Fuel Readiness Testing

Pollutant	Normal Operation (lb/hr)		Diesel Fuel Readiness Testing[a] (lb/hr)	
	Proposed	FEIR[b]	Proposed	FEIR[b]
CO	28.16	28.16	26.3	26.3
NO_x	19.32	19.32	313	313
VOC	5.34	5.34	5.20	5.20
SO_x	0.41	2.13	2.92[c]	2.92[c]
PM10	15.14	16.32	23.22	23.22

[a] Diesel fuel readiness test duration is one hour per test
[b] Source: January 2002 FEIR Tables 4.2-8 and 4.2-10; No changes due to October 2003 Addendum
[c] After implementation of mitigation measure AQ-5, requiring use of 15 parts-per-million sulfur ultra-low-sulfur diesel fuel

An individual CTG could be operated in the following eight combinations of operating modes during a single day:

a. 24 hours of normal operations only
b. 23 hours of normal operations and one hour of diesel fuel readiness testing
c. Six-hour cold startup followed by 18 hours of normal operations
d. Three-hour non-cold startup followed by normal operations
e. 23.5 hours of normal operations followed by a 0.5-hour shutdown
f. 22.5 hours of normal operations, one hour of diesel fuel readiness testing, and a 0.5-hour shutdown
g. Six-hour cold startup followed by 17.5 hours of normal operations and a 0.5 hour shutdown
h. Three-hour non-cold startup followed by normal operations and a 0.5-hour shutdown

Note that a CTG will not undergo a cold or non-cold startup and diesel fuel readiness testing on the same day, so none of these daily combinations includes both a startup and a diesel fuel readiness test.

Potential daily operating scenarios involving both CTGs were identified by assuming that one CTG is operated in one of these eight combinations of operating modes and the other CTG is operated in the same or another combination. For example, one scenario is defined as 24 hours of normal operations (combination a) for one CTG and 23 hours of normal operations plus one hour of diesel fuel readiness testing (combination b) for the other CTG. Mathematically, a total of 36 operating scenarios could be defined[1]. However, only one turbine can undergo a cold startup during a day, and the other turbine would undergo a non-cold startup after the cold startup of the first turbine is completed. This means that combinations c and g for one turbine could only occur with combinations d and h for the other turbine, which leaves the 25 daily operating scenarios defined in Table C-6.

Table C-6

CTG Daily Operating Scenarios

Scenario[a]	First CTG	Second CTG
1 (a-a)	24 hours normal operations	24 hours normal operations
2 (a-b)	24 hours normal operations	23 hours normal operations and one hour diesel fuel readiness testing
3 (a-d)	24 hours normal operations	3 hours non-cold startup and 21 hours normal operations
4 (a-e)	24 hours normal operations	23.5 hours normal operations and 0.5 hour shutdown
5 (a-f)	24 hours normal operations	22.5 hours normal operations, one hour diesel fuel readiness testing and 0.5 hour shutdown
6 (a-h)	24 hours normal operations	3 hours non-cold startup, 20.5 hour normal operations, and 0.5 hour shutdown
7 (b-b)	23 hours normal operations and one hour diesel fuel readiness testing	23 hours normal operations and one hour diesel fuel readiness testing
8 (b-d)	23 hours normal operations and one hour diesel fuel readiness testing	3 hours non-cold startup and 21 hours normal operations
9 (b-e)	23 hours normal operations and one hour diesel fuel readiness testing	23.5 hours normal operations and 0.5 hour shutdown
10 (b-f)	23 hours normal operations and one hour diesel fuel readiness testing	22.5 hours normal operations, one hour diesel fuel readiness testing and 0.5 hour shutdown
11 (b-h)	23 hours normal operations and one hour diesel fuel readiness testing	3 hours non-cold startup, 20.5 hour normal operations, and 0.5 hour shutdown
12 (c-d)	6 hours cold startup and 18 hours normal operations	3 hours non-cold startup after cold startup of first CTG and 15 hours normal operations
13 (c-h)	6 hours cold startup and 18 hours normal operations	3 hours non-cold startup after cold startup of first CTG, 14.5 hours normal operations and 0.5 hour shutdown
14 (d-d)	3 hours non-cold startup and 21 hours normal operations	3 hours non-cold startup after non-cold startup of first CTG and 18 hours normal operations
15 (d-e)	3 hours non-cold startup and 21 hours normal operations	23.5 hours normal operations and 0.5 hour shutdown
16 (d-f)	3 hours non-cold startup and 21 hours normal operations	22.5 hours normal operations, one hour diesel fuel readiness testing and 0.5 hour shutdown
17 (d-g)	3 hours non-cold startup after cold startup of second CTG and 15 hours normal operations	6 hours cold startup, 17.5 hours normal operations and 0.5 hour shutdown

[1] The 36 possible pairs are: a-a, a-b, a-c, a-d, a-e, a-f, a-g, a-h, b-b, b-c, b-d, b-e, b-f, b-g, b-h, c-c, c-d, c-e, c-f, c-g, c-h, d-d, d-e, d-f, d-g, d-h, e-e, e-f, e-g, e-h, f-f, f-g, f-h, g-g, g-h, and h-h.

Table C-6 (Continued)
CTG Daily Operating Scenarios

Scenario[a]	First CTG	Second CTG
18 (d-h)	3 hours non-cold startup and 21 hours normal operations	3 hours non-cold startup after non-cold startup of first CTG, 17.5 hours normal operations and 0.5 hour shutdown
18 (e-e)	23.5 hours normal operations and 0.5 hour shutdown	23.5 hours normal operations and 0.5 hour shutdown
20 (e-f)	23.5 hours normal operations and 0.5 hour shutdown	22.5 hours normal operations, one hour diesel fuel readiness testing and 0.5 hour shutdown
21 (e-h)	23.5 hours normal operations and 0.5 hour shutdown	3 hours non-cold startup, 20.5 hour normal operations and 0.5 hour shutdown
22 (f-f)	22.5 hours normal operations, one hour diesel fuel readiness testing and 0.5 hour shutdown	22.5 hours normal operations, one hour diesel fuel readiness testing and 0.5 hour shutdown
23 (f-h)	22.5 hours normal operations, one hour diesel fuel readiness testing and 0.5 hour shutdown	3 hours non-cold startup, 20.5 hour normal operations and 0.5 hour shutdown
24 (g-h)	6 hours cold startup, 17.5 hours normal operations and 0.5 hour shutdown	3 hours non-cold startup after cold startup of first CTG, 14.5 hours normal operation and 0.5 hour shutdown
25 (h-h)	3 hours non-cold startup, 20.5 hour normal operation and 0.5 hour shutdown	3 hours non-cold startup after non-cold startup of first CTG, 17.5 hours normal operation and 0.5 hour shutdown
[a] Letter in parenthesis are daily combinations of operating modes for each turbine as described in thext		

Daily emissions of each criteria pollutant for each of the operating scenarios were calculated to identify the scenario that leads to the peak daily emissions of each criteria pollutant. The emissions for each scenario and each criteria pollutant are summarized in Table C-7. The following equations, showing the calculations of emissions for the scenarios that result in peak daily emissions, are examples of how the emissions in Table C-7 were calculated:

Peak Daily CO (Scenario 12)

First CTG: 1 cold startup x 433.35 lb/cold startup +
18 hrs normal operations x 28.16 lb/hr
= 940.23 lb/day
Second CTG: 1 non-cold startup x 233.34 lb/non-cold startup +
15 hrs normal operations x 28.16 lb/hr
= 655.74 lb/day
Both CTGs: 940.23 lb/day + 655.74 lb/day
= 1,595.97 lb/day

Peak Daily VOC (Scenario 1)

First CTG: 24 hrs normal operations x 5.34 lb/hr
= 128.16 lb/day
Second CTG: 24 hrs normal operations x 5.34 lb/hr
= 128.16lb/day

Both CTGs: 128.16 lb/day + 128.16 lb/day
= 256.32 lb/day

Peak Daily NO_x (Scenario 24)

First CTG: 1 cold startup x 600 lb/cold startup +
17.5 hrs normal operations x 19.32 lb/hr +
1 shutdown x 22.1 lb/shutdown
= 960.20 lb/day

Second CTG: 1 non-cold startup x 300 lb/non-cold startup +
14.5 hrs normal operations x 19.32 lb/hr +
1 shutdown x 22.1 lb/shutdown
= 602.24 lb/day

Both CTGs: 960.20 lb/day + 602.24 lb/day
= 1,562.44 lb/day

Peak Daily SO_x (Scenario 7)

First CTG: 23 hrs normal operations x 0.41 lb/hr +
1 diesel fuel readiness test x 2.92 lb/diesel fuel test
= 12.35 lb/day

Second CTG: 23 hrs normal operations x 0.41 lb/hr +
1 diesel fuel readiness test x 2.92 lb/diesel fuel test
= 12.35 lb/day

Both CTGs: 12.35 lb/day + 12.35 lb/day
= 24.70 lb/day

Peak Daily PM10 (Scenario 7)

First CTG: 23 hrs normal operations x 15.14 lb/hr +
1 diesel fuel readiness test x 23.22 lb/diesel fuel test
= 371.44 lb/day

Second CTG: 23 hrs normal operations x 15.14 lb/hr +
1 diesel fuel readiness test x 23.22 lb/diesel fuel test
= 371.44 lb/day

Both CTGs: 371.44 lb/day + 371.44 lb/day
= 742.88 lb/day

Daily emissions for each operating scenario are listed in Table C-7, and the resulting peak daily emissions of each criteria pollutant is indicated in bold.

Table C-7

CTG Daily Emissions by Operating Scenario

Scenario	Daily Emissions CO (lb/day)	VOC (lb/day)	NO_x (lb/day)	SO_x (lb/day)	PM10 (lb/day)
1	1,351.68	**256.32**	927.36	19.68	726.72
2	1,349.82	256.18	1,221.34	22.19	734.80
3	1,500.54	250.71	1,169.40	19.31	696.71
4	1,344.98	254.89	939.80	19.59	722.65
5	1,343.12	254.75	1,233.78	22.10	730.73
6	1,493.84	249.28	1,181.84	19.22	692.64
7	1,347.96	256.04	1,515.32	**24.70**	**742.88**
8	1,498.68	250.57	1,463.38	21.82	704.79
9	1,343.12	254.75	1,233.78	22.10	730.73
10	1,341.26	254.61	1,527.76	24.61	738.81
11	1,491.98	249.14	1,475.82	21.73	700.72
12	**1,595.97**	207.45	1,537.56	15.73	546.64
13	1,589.27	206.02	1,550.00	15.64	542.57
14	1,564.92	229.08	1,353.48	17.71	621.28
15	1,493.84	249.28	1,181.84	19.22	692.64
16	1,491.98	249.14	1,475.82	21.73	700.72
17	1,323.02	217.10	1,359.90	19.27	609.88
18	1,558.22	227.65	1,365.92	17.62	617.21
19	1,338.28	253.46	952.24	19.49	718.58
20	1,336.42	253.32	1,246.22	22.00	726.66
21	1,487.14	247.85	1,194.28	19.12	688.57
22	1,334.56	253.18	1,540.20	24.51	734.74
23	1,485.28	247.71	1,488.26	21.63	696.65
24	1,582.57	204.59	**1,562.44**	15.54	538.50
25	1,551.52	226.22	1,378.36	17.52	613.14

C.7 LOCALIZED AIR QUALITY IMPACTS

To determine emission rates to be used for the dispersion modeling to evaluate localized air quality impacts, the 2002 FEIR analyzed CO, NO_x, SO_x and PM10 emissions from combinations of operating modes that could occur during the averaging periods for the Ambient Air Quality Standards (AAQS) for CO, NO_2, SO_2 and PM10, respectively, to identify the highest emission rates during those averaging periods. Emissions were modeled with no adjustments made for the emission reductions associated with the removal of existing equipment at the facility, allowing for prediction of the "worst-case" impact to ambient air quality at the modeled receptors.

The operating scenarios for each CTG (and cooling tower operations for PM10) and average hourly emissions for each modeled criteria pollutant that were evaluated in the January 2002 FEIR are listed in Table C-8. For averaging periods longer than one hour, the average hourly emissions are calculated by dividing the total emissions during the averaging period by the length of the averaging period, in hours. For example, the average hourly emissions for the annual PM10 averaging period are total annual PM10 emissions resulting from the listed operating scenario divided by 8,760 hours per year.

Table C-8
Operating Scenarios and Average Hourly Emissions Evaluated for Air Quality Impacts Analysis in January 2002 FEIR

Pollutant	Averaging Period	Operating Scenario[a]	Hourly Average Emissions During Averaging Period (lb/hr)
NO_2	1-hour (hr)	CTG01 in Diesel Testing, CTG02 in Normal Operation	332.6
NO_2	Annual	Both CTGs in Normal Operation + 12 Diesel Tests	39.44
CO	1-hr	CTG01 in Normal Startup, CTG02 in Normal Operation	128.16
CO	8-hr	CTG01 in Normal Startup, CTG02 in Normal Operation	128.16
SO_2[b]	1-hr	CTG01 in Diesel Testing, CTG02 in Normal Operation	100.79
SO_2[b]	3-hr	CTG01 in Diesel Testing, CTG02 in Normal Operation	100.79
SO_2[b]	24-hr	CTG01 in Diesel Testing, CTG02 in Normal Operation	100.79
SO_2[b]	Annual	Both CTGs in Normal Operation + 12 Diesel Tests	4.52
PM10	24-hr	Both CTGs in Normal Operation (23 hours each)+ Cooling Tower in Operation + both CTGs Diesel Tested (1 hour duration)	36.17
PM10	Annual	Both CTGs in Normal Operation + Cooling Tower in Operation + 12 Diesel Tests	35.61

[a] Source: January 2002 FEIR Table 4.2-16
[b] SO_x emissions during diesel-fuel readiness testing do not account for reductions from the use of 15 ppm ultra-low sulfur diesel fuel as required by Mitigation Measure AQ-5

The operating scenarios for the currently proposed project modifications that would lead to the highest hourly average emissions rates for the averaging periods for the AAQS are listed in Table C-9, along with the resulting hourly average emissions. The operating scenario for annual NO_x emissions is the most reasonably foreseeable annual operating scenario that would lead to the highest annual NO_x emissions. The hourly average emission rates in Table C-9 are the same as or lower than the rates in Table C-8, with the exception of annual NO_x emissions. Since CO, SO_x and PM10 average hourly emissions for all averaging periods in Tables C-8 and C-9 from the currently proposed project modifications were equal to or less than average hourly emissions for these pollutants calculated in the 2002 FEIR, localized air quality impacts are equal to or less than those calculated in the 2002 FEIR. As a result, further modeling for CO, SO_x and PM10 is not required, and the currently proposed project modifications would not cause significant adverse CO, SO_x or PM10 ambient air quality impacts.

Table C-9

Operating Scenarios and Average Hourly Emissions Leading to Highest Hourly Average Emissions for Ambient Air Quality Standard Averaging Periods for Currently Proposed Project Modifications

Pollutant	Averaging Period	Operating Scenario	Hourly Average Emissions During Averaging Period (lb/hr)
NO_2	1-hour (hr)	CTG01 in 1 hr Diesel Testing, CTG02 in 1 hr Normal Operation	332.6
NO_2	Annual	CTG01 and CTG02 each in 144 hours cold startup (24 cold starts each), 810 hours non-cold startup (270 non-cold startups each), 12 hours diesel fuel readiness testing (12 tests each), 147 hours shutdown (294 shutdowns), 3,759 hours normal operation, and 3,888 hours not operating (72 hours before each cold startup and 8 hours before each non-cold startup)	40.7
CO	1-hr	CTG01 in first hour of Cold Startup, CTG02 in 1 hr Normal Operation	128.16
CO	8-hr	CTG01 in 3 hrs Non-Cold Startup + 5 hrs Normal Operation; CTG02 in 3 hrs Non-Cold Startup + 2 hrs Normal Operation	82.98
SO_2	1-hr	CTG01 in 1 hr Diesel Testing, CTG02 in 1 hr Normal Operation	3.33
SO_2	3-hr	CTG01 and CTG02 each in 1 hr Diesel Testing + 2 hrs Normal Operation	2.49
SO_2	24-hr	CTG01 and CTG02 each in 1 hr Diesel Testing + 23 hrs Normal Operation	1.03
SO_2	Annual	CTG01 and CTG02 each in 12 hrs Diesel Testing + 8,748 hrs Normal Operation	0.83
PM10	24-hr	CTG01 and CTG02 each in 1 hr Diesel Testing + 23 hrs Normal Operation; Cooling Tower Operating 24 hrs	33.90
PM10	Annual	CTG01 and CTG02 each in 12 hrs Diesel Testing + 8,748 hrs Normal Operation; Cooling Tower Operating 8,760 hrs	33.25

Air quality dispersion modeling was conducted to evaluate the potential impacts of the currently proposed project modifications on annual NO_2 concentrations. Additionally, the potential impacts of NO_x emissions on one-hour NO_2 concentrations during a cold startup were also evaluated. This evaluation of NO_2 impacts during a cold startup was conducted because: (1) the peak hourly NO_x emissions during a cold startup (300 lb/hr) are close to the peak hourly NO_x emissions analyzed in the January 2002 FEIR (332.6 lb/hr); and (2) the CTG exhaust flow rate during a cold startup is lower than the flow rate during diesel-fuel readiness testing, which causes lower dispersion of the emissions, which could, in turn, lead to higher ground-level NO_2 concentrations.

Modeling Methodology

Air dispersion modeling for the current Addendum was performed using the USEPA's Industrial Source Complex Short Term 3 Ozone Limiting Method (ISC3-OLM) model (version 96113). This model assumes that 10 percent of the NO_x emissions from combustion exhaust is emitted as NO_2 and the remaining as NO. This is a conservative assumption since it is generally accepted that only five percent of the exhaust is actually NO_2. The ISC3-OLM model then uses ozone concentration data collected at a nearby monitoring station and assumes that the remaining NO emissions react with the ozone to form NO_2. If there is an insufficient level of ozone to react with all of the emitted NO, then some of the emitted NO will not react to form NO_2.

Details of how the modeling was performed and the results of the modeling are provided in the following subsections. Output listings of model runs are available for public inspection by contacting the SCAQMD's Public Information Center at (909) 396-2039.

Modeling Options

The options used in the ISC3-OLM dispersion modeling are summarized in Table C-10. U.S. EPA regulatory default modeling options were selected, except for the calm processing option. The SCAQMD's modeling guidance requires that the calm processing modeling option not be used.

The U.S. EPA's guidance was followed to address the potential influence on the ambient air concentrations of structures located near point emission sources. The latest building downwash program (Version 3.15) developed by Lakes Environmental was used to identify the structures required to be included in the ISCST3 model to address building downwash effects. The building downwash program was also used to estimate the direction-specific building dimensions, which are required as inputs by the ISCST3 model, to address the influence of nearby structures on the ambient air concentrations.

Table C-10
Dispersion Modeling Options for ISC3-OLM

Feature	Option Selected
Terrain processing selected	Yes
Meteorological data input method	Card Image
Rural-urban option	Urban
Wind profile exponents values	Defaults
Vertical potential temperature gradient values	Defaults
Program calculates final plume rise only	Yes
Program adjusts all stack heights for downwash	Yes
Concentrations during calm period set = 0	No
Aboveground (flagpole) receptors used	No
Buoyancy-induced dispersion used	Yes
Years of surface data	1999, 2001, 2002
Years of upper air data	1999, 2001, 2002

Meteorological and Ozone Data for ISC3-OLM

Three years of meteorological and ozone data, from 1999, 2001 and 2002, were used for the dispersion modeling. Surface meteorological data from the Burbank-Glendale-Pasadena airport monitoring station for 1999, 2000 and 2001 was used for performing the dispersion modeling along with ozone data from the SCAQMD East Fernando Valley monitoring station. Upper air sounding data used to estimate hourly mixing heights were gathered at the San Diego Miramar Naval Air Station. These years were selected because the SCAQMD requires the use of the most recent three years with complete, available data when using the ozone-limiting method. Complete meteorological and ozone data were not available for 2000 or 2003.

Receptors for ISC3-OLM

Appropriate model receptors must be selected to determine the worst-case modeling impacts. A grid of receptors was placed along the fence line with 100 meter spacing and extending out to five kilometers from the fence line with 1,000 meter spacing. The location with the highest concentration was then found. Additional modeling analysis was then performed using a refined grid (100 meter spacing) of receptors centered on the location of highest impact from the 1,000 meter spacing modeling analysis. No receptors were placed within the VGS site property line.

Terrain heights for all receptors were determined from commercially available digital terrain elevations developed by the U.S. Geological Survey by using its Digital Elevation Model (DEM). The DEM data provide terrain elevations with one-meter vertical resolution and 30 meters horizontal resolution based on a Universal Transverse Mercator (UTM) coordinate system. For each receptor location, the terrain elevation was set to the elevation for the closest DEM grid point.

Source Parameters

The source parameter inputs and NO_x emission rates used for the dispersion modeling to calculate impacts of NO_x emissions during cold startup on hourly average NO_2 concentrations are summarized in Table C-11. Source parameter inputs and NO_x emission rates for the dispersion modeling to calculate annual average NO_2 impacts are summarized in Table C-12. The annual average NO_x emission rate for each CTG operating mode, in grams per second, was calculated by dividing annual emissions during the operating mode, in grams, by the number of seconds in a year. The CTGs were modeled as point sources.

Table C-11
Dispersion Modeling Source Location and Stack Parameters for Hourly NO_x Modeling During Cold Startups

Source ID	Easting (m)	Northing (m)	Elevation (m)	Release Height (m)	Temp (K)	Stack Vel (m/s)	Stack Dia (m)	NO_x (g/s)
CTG01	371935	3790125	284	42.7	341	9.2	5.8	37.8
CTG02	371965	3790150	285	42.7	341	9.2	5.8	37.8
Note - Although two turbines are shown in the table, only one turbine will be in cold startup at any time. NO_2 concentrations caused by emissions from each turbine were examined to identify the highest concentration caused by emissions from either turbine.								

Table C-12
Dispersion Modeling Source Location and Stack Parameters for Annual NO_x Modeling

CTG Mode	Source ID	Easting (m)	Northing (m)	Elevation (m)	Release Height (m)	Temp (K)	Stack Vel (m/s)	Stack Dia (m)	NO_x (g/s)
Cold Start	CTG01	371935	3790125	284	42.7	346	10.6	5.8	0.21
Cold Start	CTG02	371965	3790150	285	42.7	346	10.6	5.8	0.21
Non-cold Start	CTG01	371935	3790125	284	42.7	346	10.7	5.8	1.63
Non-cold Start	CTG02	371965	3790150	285	42.7	346	10.7	5.8	1.63
Normal	CTG01	371935	3790125	284	42.7	358	20.9	5.8	1.05
Normal	CTG02	371965	3790150	285	42.7	358	20.9	5.8	1.05
Shutdown	CTG01	371935	3790125	284	42.7	346	10.7	5.8	0.05
Shutdown	CTG02	371965	3790150	285	42.7	346	10.7	5.8	0.05
Diesel Testing	CTG01	371935	3790125	284	42.7	415	22.2	5.8	0.05
Diesel Testing	CTG02	371965	3790150	285	42.7	415	22.2	5.8	0.05

Dispersion Modeling Results

The ISC3-OLM model was used to estimate annual-average NO_2 concentration increases caused by emissions from the proposed project for 1999, 2001 and 2002. The highest modeled annual-average NO_2 concentration increase caused by the proposed project during these three years was then added to the highest annual-average NO_2 concentration recorded at the East San Fernando Valley monitoring station during the years 2001 through 2003 (the most recent three years with complete NO_2 monitoring data) for comparison with the annual-average NO_2 ambient AAQS.

Results of the annual-average NO_2 modeling are summarized in Table C-13. The highest modeled annual-average NO_2 concentration increase caused by the proposed project during 1999, 2000 or 2002 was 0.9 $\mu g/m^3$ during 1999. The highest annual-average NO_2 concentration recorded at the East San Fernando Valley monitoring station during the years 2001 through 2003 was 77.1 $\mu g/m^3$ during 2001 The resulting total NO_2 concentration (modeled increase plus existing background) of 78.0 $\mu g/m^3$ was below the annual-average AAQS of 100 $\mu g/m^3$. Therefore, the currently proposed project modifications would not cause significant adverse annual NO_2 air quality impacts.

Table C-13
Results of Modeled Ambient Annual-Average NO_2 Impacts for Currently Proposed Project Modifications

Maximum Predicted Impact ($\mu g/m^3$)[a]	Maximum Annual-Average Concentration at East San Fernando Valley Monitoring Station ($\mu g/m^3$)[b]	Total Concentration ($\mu g/m^3$)
0.9 (1999)	77.1 (2001)	78.0

[a] Highest modeled annual-average concentration during 1999, 2000 or 2001
[b] Highest measured annual average concentration from 2001 through 2003

For comparison with the one-hour average NO_2 AAQS, the ISC3-OLM model was used to estimate maximum hourly-average NO_2 concentrations during each month of 1999, 2001 and 2002 for a total of 36 modeling runs. For these modeling runs, the NO_x emission rate was set to the 300 lb/hour maximum emission rate during a cold startup. The highest one-hour average impact for each month was added to the highest one-hour average NO_2 concentration measured during the same month from 2001 through 2003 at the East San Fernando Valley monitoring station for comparison with the AAQS.

The modeling results for one-hour average impacts indicated that NO_x emissions from the proposed project modifications would cause or contribute to a violation of the state AAQS (AAQS) for NO_2 (470 $\mu g/m^3$) in the months of January and December. In order to receive permitting approval for the proposed project modifications, the project must comply with SCAQMD Rule 1303 modeling requirements which do not allow approval of a project if modeling shows that the emissions from the project cause or contribute to an exceedance of any AAQS. To avoid violating SCAQMD Rule 1303, the SCAQMD will impose the following permit conditions: limit the cold startup operation to one gas turbine at a time and cold startups cannot occur during the four-hour period from 3 a.m. to 7 a.m. during the months of December and January. Under these limitations, air quality impacts from the proposed project modifications would comply with SCAQMD Rule 1303, i.e., would not cause or contribute to a violation of any NO_2 AAQS. LADWP has accepted these change of permit conditions for startup operations.

NO_2 modeling was rerun incorporating the startup limitations. The highest one-hour average impact for each month from February to November was added to the highest one-hour average NO_2 concentration measured during the month from 2001 through 2003 at the East San Fernando Valley monitoring station for comparison with the significance threshold. The highest one-hour average impact for each of December and January was added to the highest one-hour average NO_2 concentration measured during the month from 2001 through 2003 (except during the hours of 3 a.m. to 7 a.m.) at the East San Fernando Valley monitoring station. Modeled one-hour average NO_2 ambient air quality impacts for the currently proposed project modifications are summarized in Table C-14.

Table C-14
Results of Modeled Ambient One-Hour Average NO_2 Impacts for Currently Proposed Project Modifications with Startup Limitations

Month	Maximum Predicted Impact (μg/m³)[a]	Maximum Monthly One-Hour Average Concentration at East San Fernando Valley Monitoring Station (μg/m³)[b]	Total Concentration (μg/m³)
January	114.0 (1999)	236.9 (2003)	350.9
February	109.1 (1999)	253.8 (2002)	362.9
March	114.4 (2001)	173.0 (2001)	287.4
April	108.8 (2001)	180.5 (2001)	289.3
May	118.3 (1999)	223.7 (2001)	342.0
June	107.4 (2001)	193.6 (2002)	301.0
July	107.3 (2002)	167.3 (2002)	274.6
August	116.3 (2002)	208.7 (2001)	325.0
September	113.6 (2002)	338.4 (2002)	452.0
October	129.0 (1999)	253.8 (2003)	382.8
November	83.6 (2002)	248.2 (2001)	331.8
December	126.5 (2001)	263.2 (2003)	389.7
Highest Total Concentration			**452.0**

[a] Maximum modeled during the month for 1999, 2001 and 2002.
[b] Maximum measured during the month from 2001 through 2003; For December and January the data does not include the hours of 3am to 7am.

C.8 REFERENCES

South Coast Air Quality Management District. 2003. General Instruction Book for the AQMD 2002-2003 Annual Emissions Reporting Program, Appendix B.

U.S. Environmental Protection Agency. 2000. Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources, Section 3.1, “Stationary Gas Turbines,” April.

ATTACHMENT C.1

SHUTDOWN EMISSION DETAILS

LADWP VALLEY COMBINED CYCLE GENERATING FACILTY (CCGF)
CRITERIA POLLUTANT EMISSIONS
NORMAL SHUT DOWN SCENARIO
Natural Gas Use by the Combustion Turbine

Device ID Number:	VCC 1
No. of Devices:	2, Emissions shown for one
Process Equipment Description:	GE PG7241 FA, 171,700 KW
Fuel Type:	Natural Gas
Process Units:	MMSCF

Control Equipment:	Selective Catalytic Reduction, CO Catalyst, and Dry Low NOx Combustor
Yearly Emis. Est. Equation:	F_y x EF
Max Hourly Emis. Est. Equation:	F_m x EF

Parameter Symbols/Names	**Values**	
F_y = Total Yearly Amount of Fuel Burned (one CT)	NA	MMSCF
F1 = Fuel, Time 0 to 5 minutes (5 minutes)	0.132	MMSCF
F2 = Fuel, Time 5 to 10 minutes (5 minutes)	0.112	MMSCF
F3 = Fuel, Time 10 to 15 minutes (5 minutes)	0.086	MMSCF
F4 = Fuel, Time 15 to 20 minutes (5 minutes)	0.069	MMSCF
F5 = Fuel, Time 20 to 30 minutes (10 minutes)	0.057	MMSCF
Process Operation Schedule	SCR on for entire shudown cycle	

Criteria Species Name	0 to 5 min Emission Factor (lb/MMscf)	5 to 10 min Emission Factor (lb/MMscf)	10 to 15 min Emission Factor (lbs/MMscf)	15 to 20 min Emission Factor (lbs/MMscf)	20 to 30 min Emission Factor (lbs/MMscf)	
CO	14.39	14.39	14.39	14.39	28.77	
VOC	2.73	2.73	2.73	2.73	2.73	
PM_{10}	7.67	7.67	7.67	7.67	7.67	
SO_2	0.24	0.24	0.24	0.24	0.24	
NH_3	7.25	7.25	7.25	7.25	7.25	

Criteria Species Name	0 to 5 min Emissions (lbs)	5 to 10 min Emissions (lbs)	10 to 15 min Emissions (lbs)	15 to 20 min Shutdown (lbs)	20 to 30 min Shutdown (lbs)	Total (lbs)
CO	1.897	1.609	1.236	0.990	1.649	7.38
VOC	0.360	0.305	0.235	0.188	0.156	1.24
PM_{10}	1.011	0.858	0.659	0.528	0.440	3.50
SO_2	0.032	0.027	0.021	0.017	0.014	0.11
NH_3	0.956	0.811	0.623	0.499	0.415	3.30

LADWP VALLEY COMBINED CYCLE GENERATING FACILTY (CCGF)
DEVELOPMENT OF EMISSION FACTORS
NORMAL SHUTDOWN
Natural Gas Use by the Combustion Turbines

1. The new combustion turbines (CTs) are GE PG7241 FAs 171.7 MW (171,700 kW) turbine [1].
2. The heating input required is 9,205 Btu/kW-hr (LHV) and the power output is 178 MW [1].
3. The CTs will have dry Lo NOx combustors and SCR/CO catalyst. [2]
4. The CTs will use natural gas with a HHV of 1050 Btu/scf [2].
5. Emission limits are 6 ppmv for carbon monoxide (CO), 2 ppmv for volatile organic compounds (VOC) and 5 ppmv for ammonia (NH_3)[3] for controlled operations.
6. Emission limits are assumed to be at 15% O_2.
7. Manufacturer's emissions data for CO were taken as concentration in stated stack gas flow rate.
8. Manufacturer's value for VOC emissions used for all cases since AP-42 factors are less.

Calculate Maximum Firing Rate (MFR) for the CT in Btu/hr

Maximum Firing Rate = 178,000 kW X 9205 Btu/kW-hr

Size (kW)	Factor (Btu/kW-hr)	LHV (Btu/scf)	HHV (Btu/scf)	HHV (Btu/lb)	MFR (Btu/hr)
178000	9205	953	1,050	23137	1,638,490,000

Maximum Hourly Fuel Consumption Rate (MMscf) = MFR/(LHV x 1,000,000)

Maximum Hourly Fuel Consumption Rate (MMscf/hr) = 1.719 MMscf/hr

Fuel Consumption during normal shut off = Fuel (lbs/hr) x time period (hr)

Stack Gas Flow = Stack Gas Flow Rate (lbs/sec) x 379 (scf/lb-mole) / MW of Stack Gas (lbs/lb-mole)

Time (minutes)	Fuel [4] (% of max)	Fuel (MMscf/hr)	Fuel (MMscf)
0 to 5	92	1.581	0.1318
5 to 10	78	1.341	0.1118
10 to 15	60	1.031	0.0859
15 to 20	48	0.825	0.0688
20 to 30	20	0.344	0.0573

Exhaust Volume (DSCF/MMBtu) = 8710 DSCF/MMBtu x 20.9/(20.9 -%O_2) [7]
Exhaust Volume (DSCF/MMBtu) = 30,854 SCF/MMBtu at 15% Oxygen

Time period (minutes)	Time Period Fuel Use (MMscf)	Time Period Heat Input (MMBtu)	Exhaust Vol. (SCF/Time)
0 to 5	0.132	138.4	4,270,194
5 to 10	0.112	117.4	3,622,260
10 to 15	0.086	90.2	2,783,031
15 to 20	0.069	72.2	2,227,659
20 to 30	0.057	60.2	1,857,411

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Calculate Molecular Weight of Natural Gas

Compound	Mole% [5]	MW	Weighted MW
methane	94	16	**15**
ethane	3	30	**0.9**
propane	2	44	**0.9**
CO_2	1	44	**0.4**
Total			**17.2**

$$\text{EL (lbs/MMBtu)} = \frac{\text{Exhaust Volume x Concentration x MW of Pollutant}^{(6)}}{1{,}000{,}000 \times 379}$$

CO Emissions

Time Period (minutes)	Exhaust Vol (WSCF/MMBtu)	Conc. [3] (ppmv)	MW (lb/lb-mole)	EL (lb/MMBtu)
0 to 5	30,854	**6.0**	28	**0.0137**
5 to 10	30,854	**6.0**	28	**0.0137**
10 to 15	30,854	**6.0**	28	**0.0137**
15 to 20	30,854	**6.0**	28	**0.0137**
20 to 30	30,854	**12**	28	**0.0274**

Convert Emission Limit (EL) in lb/MMBtu to Emission Factor in lb/MMscf, EF = EL x HHV (Btu/scf)

Time Period (minutes)	Duration (minutes)	EL (lb/MMBtu)	HHV (Btu/scf)	EF (lb/MMscf)
0 to 5	5	0.0137	1050	**14.39**
5 to 10	5	0.0137	1050	**14.39**
10 to 15	5	0.0137	1050	**14.39**
15 to 20	5	0.0137	1050	**14.39**
20 to 30	10	0.0274	1050	**28.77**

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Convert Emission Limits (EL) from ppmv to lb/MMBtu for VOC and NH_3.

EL (lbs/MMBtu) = $\frac{\text{Exhaust Volume x Concentration x MW of Pollutant}^{(7)}}{\text{1,000,000 x 379}}$

Exhaust Volume (DSCF/MMBtu) = 8710 DSCF/MMBtu x 20.9/(20.9 -%O_2) [8]

NH_3 and VOC Emissions

Pollutant	Oxygen (%)	Exhaust Vol (DSCF/MMBtu)	Conc. [3] (ppmv)	MW (lb/lb-mole)	EL (lb/MMBtu)
VOC (CH_4)	15	**30,854**	2	16	**0.0026**
NH_3	15	**30,854**	5	17	**0.0069**

Pollutant	EL (lb/MMBtu)	HHV (Btu/scf)	EF (lb/MMscf)
VOC (CH_4)	0.0026	1050	**2.73**
NH_3	0.0069	1050	**7.25**

Calculate PM10 and SO2 Emissions

Pollutant	Emission Factor [7] (lb/MMBtu)	HHV (Btu/scf)	Emission Factor (lb/MMscf)
PM10	0.0066	1050	**6.93**
SO_2			**0.60**
SO_2 Conversion Factor = 60%			**0.24**

Calculate PM_{10} from Conversion of SO_2 to ammonium sulfate
SO_2 to SO_3 =60% molar conversion [6]
SO_3 to ammonium sulfate: 1 mole SO_3 = 1 mole of ammonium sulfate [8]

SO_2 (lbs/BTU)	SO_2 (lb-mole/MMBtu)	SO_3 (lb-mole/MMBtu)	PM10 (lb/MMBtu)	**PM10 (lbs/MMscf)**
0.000571	8.92E-06	5.35E-06	7.07E-04	**0.742**

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Exhaust Volume (WSCF/MMBtu) = 10,610 WSCF/MMBtu x 20.9/(20.9 -%O_2) [8]
Actual Oxygen = 12.82 **%**[1]
Stack Gas Flow Rate, ACF = **Stack Gas Flow (SCF) x** **[Stack Gas Temp (^oR)]**

^oR = ^oF + 460
Standard Temp = 60 ^oF

Determine Stack Gas Velocity

Time Period	Duration (minutes)	Exhaust Vol (WSCF/MMBtu)	Heat Input (MMBtu/sec)	Exhaust Flow (WSCFS)	Stack Temp. [4] (^oF)	Exhaust Flow (WACFS)
0 to 5	5	**27,444**	0.4613	**12,660**	185	**15,703**
5 to 10	5	**27,444**	0.3913	**10,739**	185	**13,320**
10 to 15	5	**27,444**	0.3007	**8,252**	185	**10,236**
15 to 20	5	**27,444**	0.2407	**6,606**	175	**8,067**
20 to 30	10	**27,444**	0.1003	**2,753**	125	**3,097**

Time Period	Stack Inside Diameter [9] (FT)	Stack Exit Velocity (FT/SEC)	Stack Exit Velocity (M/SEC)	Stack Inside Diameter (M)	Stack Height [9] (FT)	Stack Height (M)
0 to 5	18	**61.71**	**18.81**	**5.49**	140	**42.67**
5 to 10	18	**52.34**	**15.95**	**5.49**	140	**42.67**
10 to 15	18	**40.22**	**12.26**	**5.49**	140	**42.67**
15 to 20	18	**31.70**	**9.66**	**5.49**	140	**42.67**
20 to 30	18	**12.17**	**3.71**	**5.49**	140	**42.67**

Average Stack Gas Velocity = $(V_1T_1+V_2T_2+V_3T_3+V_4T_{4+}V_5T_5)/(T_1+T_2+T_3+T_4+T_5)$
Average Stack Gas Velocity (ft/sec) = **35.05**
Average Stack Gas Velociy (m/sec) = **10.68**

Average Stack Gas Temperature = $(Temp_1T_1+Temp_2T_2+Temp_3T_3+Temp_4T_{4+}Temp_5T_5)/(T_1+T_2+T_3+T_4+T_5)$
Average Stack Gas Temperature (^oF) = **163**

(1) Specification from GE technical bulletin and Cycle Deck Run for 22 ^oF.
(2) Information provided by LA DWP in a meeting held on 1-24-01.
(3) Specifications from LA DWP (Generation - 2000 Project Overview).
CO w/o control assumed at 12 ppm (2 x controlled value).
(4) GE Shutdown Data for Turbine 7FA (3-13-00). Turbine exhaust temperature used as the basis for stack outlet.
(5) SCR Bid specification (no. 9628) from LA DWP. Natural gas LHV calculated to be 953 Btu/scf. Expected sulfur content used.
(6) PM10 and Sulfur Dioxide emission factor is from AP-42, Table 3.1-2a.
(7) Taken from SCAQMD Title V Technical Guidance Manual, page A-20, 1998.
(8) EPA Method 19, 40 CFR Part 60.
(9) Information supplied by R. Gentner on 8-23-01.