# Appendix A

## Emission Factor Derivations

The following physical constants and standard conditions were utilized to derive the criteria-pollutant emission factors used to calculate criteria pollutant and toxic air contaminant emissions.

| | |
|---|---|
| standard temperature[a]: | 70°F |
| standard pressure[a]: | 14.7 psia |
| molar volume: | 385.3 dscf/lbmol |
| ambient oxygen concentration: | 20.95% |
| dry flue gas factor[b]: | 8600 dscf/MM BTU |
| natural gas higher heating value: | 1030 BTU/dscf |

[a]standard conditions per BAAQMD Regulation 1, Section 228.

[b]F-factor is based upon the assumption of complete stoichiometric combustion of natural gas. In effect, it is assumed that all excess air present before combustion is emitted in the exhaust gas stream. Value shown reflects the typical composition and heat content of utility-grade natural gas in San Francisco bay area.

Table A-1 summarizes the regulated air pollutant emission factors that were used to calculate mass emission rates for each source. All units are pounds per million BTU of natural gas fired based upon the high heating value (HHV). All emission factors reflect abatement by applicable control equipment.

### Table A-1
### Controlled Regulated Air Pollutant Emission Factors for Gas Turbines and HRSGs

| Pollutant | Source | | | |
|---|---|---|---|---|
| | Gas Turbine | | Gas Turbine & HRSG Combined | |
| | lb/MM BTU | lb/hr | lb/MM BTU | lb/hr |
| Nitrogen Oxides (as $NO_2$) | 0.00723[a] | 13.73 | 0.00723[a] | 19.02 |
| Carbon Monoxide | 0.0088[b] | 16.71 | 0.0088[b] | 23.15 |
| Precursor Organic Compounds | 0.0014 | 2.65 | 0.00252 | 6.64 |
| Particulate Matter ($PM_{10}$) | 0.00474 | 9 | 0.00437 | 11.5 |
| Sulfur Dioxide | 0.0007 | 1.33 | 0.0007 | 1.84 |
| Sulfuric Acid Mist ($H_2SO_4$) | 0.00107 | 2.03 | 0.00107 | 2.82 |

[a]based upon the permit condition stack gas emission limit of 2.0 ppmvd $NO_x$ @ 15% $O_2$ that reflects the use of dry low-$NO_x$ combustors at the CTG, low-$NO_x$ burners at the HRSG, and abatement by the proposed A-1 and A-2 Selective Catalytic Reduction Systems with ammonia injection

[b]based upon the permit condition stack gas emission limit of 4 ppmvd CO @ 15% $O_2$

## Regulated Air Pollutants

### NITROGEN OXIDE EMISSION FACTORS

#### Gas Turbine and Heat Recovery Steam Generator Combined

The combined $NO_x$ emissions from the GT and HRSG will be limited to 2.0 ppmv, dry @ 15% $O_2$. This emission limit will also apply when the HRSG duct burners are in operation. This concentration is converted to a mass emission factor as follows:

(2.0 ppmvd)(20.95 - 0)/(20.95 - 15) = 7.04 ppmv $NO_x$, dry @ 0% $O_2$

$(7.04/10^6)$(1 lbmol/385.3 dscf)(46.01 lb $NO_2$/lbmol)(8600 dscf/MM BTU)

= **0.00723 lb $NO_2$/MM BTU**

The $NO_x$ mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:

(0.00723 lb/MM BTU)(1,898.8 MM BTU/hr) = **13.73 lb $NO_x$/hr**

The $NO_x$ mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of the gas turbine and HRSG and is calculated as follows:

(0.00723 lb/MM BTU)(2,630.8 MM BTU/hr) = **19.02 lb $NO_x$/hr**

### CARBON MONOXIDE EMISSION FACTORS

#### Gas Turbine and Heat Recovery Steam Generator Combined

The combined CO emissions from the GT and HRSG duct burner will be limited by permit condition to a maximum controlled CO emission concentration of 4 ppmv, dry @ 15% $O_2$ during all operating modes except gas turbine start-up and shutdown. The emission factor corresponding to this emission concentration is calculated as follows:

(4 ppmv)(20.95 - 0)/(20.95 - 15) = 14.08 ppmv, dry @ 0% $O_2$

$(14.08/10^6)$(lbmol/385.3 dscf)(28 lb CO/lbmol)(8600 dscf/MM BTU)

= **0.0088 lb CO/MM BTU**

The CO mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:

(0.0088 lb/MM BTU)(1,898.8 MM BTU/hr) = **16.71 lb CO/hr**

The CO mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of each gas turbine and HRSG and is calculated as follows:

(0.0088 lb/MM BTU)(2,630.8 MM BTU/hr) = **23.15 lb CO/hr**

## PRECURSOR ORGANIC COMPOUND (POC) EMISSION FACTORS

### Gas Turbine

Calpine estimates a maximum POC (non-methane, non-ethane hydrocarbon) emission rate of 2.65 lb/hour for full load operation of the gas turbine alone.

The mass emission rate converts to an emission factor as follows:

POC = (2.65 lb/hr)/(1,898.8 MM BTU/hr) = **0.0014 lb/MM BTU**

Converting to a concentration yields:

[(0.0014 lb/MM BTU)($10^6$)(385.3 dscf/lbmol)]/[(16 lb $CH_4$/lb-mol)(8600 dscf/MM BTU)]

= 3.92 ppmvd @ 0% $O_2$

Converting to 15% $O_2$:

(3.92 ppmvd)(20.95 – 15)/(20.95) = 1.11 ppmvd @ 15% $O_2$

### Gas Turbine and Heat Recovery Steam Generator Combined

Calpine estimates a maximum POC (non-methane, non-ethane hydrocarbon) emission rate of 6.64 lb/hr for full load operation of the gas turbine with duct burner firing and steam injection power augmentation.

This converts to an emission factor of:

(6.64 lb/hr)/(2,630.8 MM BTU/hr) = **0.00252 lb/MM BTU**

Converting to a concentration yields:

[(0.00252 lb/MM BTU)($10^6$)(385.3 dscf/lbmol)]/[(16 lb $CH_4$/lb-mol)(8600 dscf/MM BTU)]

= 7.05 ppmvd @ 0% $O_2$

Converting to 15% $0_2$: (7.05 ppmvd)(20.95 – 15)/(20.95) = 2 ppmvd @ 15% $O_2$

## PARTICULATE MATTER ($PM_{10}$) EMISSION FACTORS

### Gas Turbine

Calpine has proposed a maximum $PM_{10}$ emission rate of 9 lb/hr at maximum load for each gas turbine based upon recent source tests conducted at the Los Medanos Energy Center in Pittsburg, CA and the Sutter Power Plant located near Yuba City, CA.

The corresponding $PM_{10}$ emission factor is therefore:

(9 lb $PM_{10}$/hr)/(1,898.8 MM BTU/hr) = **0.00474 lb $PM_{10}$/MM BTU**

The following stack data will be used to calculate the grain loading at standard conditions for full load gas turbine operation without duct burner firing to determine compliance with BAAQMD Regulation 6-310.3.

The following worst-case stack gas characteristics (with respect to grain loading) during full load operation w/o duct burner firing occur at the lowest expected typical ambient temperature of 45°F.

| | |
|---|---|
| $PM_{10}$ mass emission rate: | 9 lb/hr |
| Exhaust gas flow rate: | 887,080 acfm @ 13.42% $O_2$ and 189°F |
| moisture content: | 8.78% by volume |

Converting flow rate to standard conditions:

(887,080 acfm)(70 + 460 °R/189 + 460 °R)(1 – 0.0878) = 660,821 dscfm

Converting to grains/dscf:

(9 lb $PM_{10}$/hr)(1 hr/60 min)(7000 gr/lb)/(660,821 dscfm) = 0.0016 gr/dscf

Converting to 6% $O_2$ basis:

(0.0016 gr/dscf)[(20.95 - 6)/(20.95 – 13.42)] = 0.0032 gr/dscf @ 6% $O_2$

## Gas Turbine and HRSG Combined

Calpine has proposed a maximum $PM_{10}$ emission rate of 11.5 lb/hr at the maximum combined firing rate of 2,630.8 MM BTU/hr during duct burner firing and steam injection power augmentation based upon recent source tests conducted at the Los Medanos Energy Center in Pittsburg, CA and the Sutter Power Plant located near Yuba City, CA.

The corresponding $PM_{10}$ emission factor is therefore:

(11.5 lb $PM_{10}$/hr)/(2,630.8 MM BTU/hr) = **0.00437 lb $PM_{10}$/MM BTU**

It is assumed that this $PM_{10}$ emission factor includes the potential formation of secondary $PM_{10}$ such as particulate sulfates.

The following stack data will be used to calculate the grain loading for full load turbine operation with duct burner firing at standard conditions to determine compliance with BAAQMD Regulation 6-310.3.

The following worst-case stack gas characteristics (with respect to grain loading) during full load with duct burner firing occur at the highest expected "typical" ambient temperature of 98°F.

| | |
|---|---|
| $PM_{10}$ mass emission rate: | 11.5 lb/hr |
| typical flow rate: | 911,489 acfm @ 9.88% $O_2$ and 155°F |
| typical moisture content: | 11.95% by volume |

Converting flow rate to standard conditions:

(911,489 acfm)(70 + 460 °R/155 + 460 °R)(1 - 0.1195) = 892,119 dscfm

Converting to grains/dscf:

(11.5 lb $PM_{10}$/hr)(1 hr/60 min)(7000 gr/lb)/(892,119 dscfm) = 0.0015 gr/dscf

Converting to 6% $O_2$ basis:

(0.0015 gr/dscf)[(20.95 - 6)/(20.95 – 11.95)] = 0.0025 gr/dscf @ 6% $O_2$

## SULFUR DIOXIDE EMISSION FACTORS

Gas Turbine & Heat Recovery Steam Generator

The $SO_2$ emission factor is based upon an expected maximum natural gas sulfur content of 2500 gr/$10^6$ scf of natural gas and a higher heating value of 1022 BTU/scf.

The sulfur emission factor is calculated as follows:

(2500 gr/$10^6$ scf)(2 lb $SO_2$/lb S)(scf/1022 BTU)(1 lb/7000 gr)($10^6$ BTU/MM BTU)

= **0.0007 lb $SO_2$/MM BTU**

The corresponding mass $SO_2$ emission rate at the maximum combined firing rate of 2,630.8 MM BTU/hr is:

(0.0007 lb $SO_2$/MM BTU)(2,630.8 MM BTU/hr) = 1.84 lb/hr

The corresponding $SO_2$ mass emission rate at the maximum gas turbine firing rate of 1,898.8 MM BTU/hr is:

(0.0007 lb $SO_2$/MM BTU)(1,898.8 MM BTU/hr) = 1.33 lb/hr

This is converted to an emission concentration as follows:

(0.0007 lb $SO_2$/MM BTU)(385.3 dscf/lb-mol)(lb-mol/64.06 lb $SO_2$)($10^6$ BTU/8600 dscf)

= 0.49 ppmvd $SO_2$ @ 0% $O_2$

which is equivalent to:

(0.49 ppmvd)(20.95 - 15)/20.95 = 0.14 ppmv $SO_2$, dry @ 15% $O_2$

## SULFURIC ACID MIST EMISSION FACTORS

Gas Turbine & Heat Recovery Steam Generator

The $H_2SO_4$ emission factor is based upon an expected maximum natural gas sulfur content of 2500 gr/$10^6$ scf of natural gas and a higher heating value of 1022 BTU/scf. To predict absolute worst-case emissions, it is assumed that all of the sulfur contained in the fuel is converted to sulfuric acid mist.

The sulfuric acid mist emission factor is calculated as follows:

(2500 gr/$10^6$ scf)(98 lb $H_2SO_4$/32 lb S)(scf/1022 BTU)(1 lb/7000 gr)($10^6$ BTU/MM BTU)

= **0.00107 lb $SO_2$/MM BTU**

The corresponding mass $SO_2$ emission rate at the maximum combined firing rate of 2,630.8 MM BTU/hr is:

(0.00107 lb $SO_2$/MM BTU)(2,630.8 MM BTU/hr) = 2.82 lb/hr

The corresponding $SO_2$ mass emission rate at the maximum gas turbine firing rate of 1,898.8 MM BTU/hr is:

(0.00107 lb $SO_2$/MM BTU)(1,898.8 MM BTU/hr) = 2.03 lb/hr

# Table A-2
# Controlled Regulated Air Pollutant Emission Factors for

# S-7 Auxiliary Boiler

| Pollutant | lb/MM BTU | lb/hr |
|---|---|---|
| Nitrogen Oxides (as $NO_2$) | 0.0114 | 1.47 |
| Carbon Monoxide | 0.0386 | 5.0 |
| Precursor Organic Compounds | 0.0044 | 0.6 |
| Particulate Matter ($PM_{10}$) | 0.0205 | 2.65 |
| Sulfur Dioxide | 0.0007 | 0.09 |
| Sulfuric Acid Mist ($H_2SO_4$) | 0.00107 | 0.14 |

[a]based upon the permit condition stack gas emission limit of 9 ppmvd $NO_x$ @ 3% $O_2$ that reflects the use of dry low-$NO_x$ combustors and abatement by the proposed A-8 Selective Catalytic Reduction Systems with ammonia injection

[b]based upon the permit condition stack gas emission limit of 50 ppmvd CO @ 3% $O_2$ that reflects the use of dry low-$NO_x$ combustors and abatement by the proposed A-7 Oxidation Catalyst

## NITROGEN OXIDE EMISSION FACTOR

The auxiliary boiler $NO_x$ emissions will be limited to the BACT level of 9 ppmv, dry @ 3% $O_2$. This concentration is converted to a mass emission factor as follows:

(9 ppmvd)(20.95 - 0)/(20.95 - 3) = 10.5 ppmv, dry @ 0% $O_2$

$[(10.5/10^6)/385.3$ dscf/lbmol](46.01 lb $NO_2$/lbmol)(8600 dscf/MM BTU)

= **0.0108 lb $NO_2$/MM BTU**

The applicant calculated a slightly higher emission rate of **0.0114 lb $NO_2$/MM BTU**.

The corresponding $NO_x$ mass emission rate based upon the maximum firing rate of an auxiliary boiler is calculated as follows:

(0.0114 lb/MM BTU)(129 MM BTU/hr) = **1.47 lb $NO_x$/hr**

## CARBON MONOXIDE EMISSION FACTOR

Pursuant to current BACT Guidelines and vendor guarantees, the auxiliary boiler will achieve a CO emission concentration of 50 ppmv, dry @ 3% $O_2$. The emission factor corresponding to this emission concentration is calculated as follows:

(50 ppmv)(20.95 - 0)/(20.95 - 3) = 58.35 ppmv, dry @ 0% $O_2$

$(58.35/10^6)$(lbmol/385.3 dscf)(28 lb CO/lbmol)(8600 dscf/MM BTU)

= **0.0365 lb CO/MM BTU**

The applicant calculated a slightly higher emission rate of **0.0386 lb CO/MM BTU**.

The corresponding CO mass emission rate in lb/hr based upon the maximum firing rate of an auxiliary boiler is calculated as follows:

(0.0386 lb/MM BTU)(129 MM BTU/hr) = **5 lb CO/hr**

## PRECURSOR ORGANIC COMPOUND (POC) EMISSION FACTOR

The maximum POC (as $CH_4$) emission factor for the auxiliary boiler is based upon a vendor specification of **0.0044 lb POC/MM BTU**.

This converts to a **POC mass emission rate** of:

(0.0044 lb/MM BTU)(129 MM BTU/hr) = **0.6 lb/MM BTU**

Converting to a concentration yields:

[(0.0044 lb/MM BTU)($10^6$)(385.3 dscf/lbmol)]/[(16 lb $CH_4$/lb-mol)(8600 dscf/MM BTU)]

= 12.32 ppmvd @ 0% $O_2$

Converting to 3% $O_2$:

(12.32 ppmvd)(20.95 – 3)/(20.95) = 10.55 ppmvd @ 3% $O_2$

## PARTICULATE MATTER ($PM_{10}$) EMISSION FACTOR

The $PM_{10}$ emission factor is based upon a vendor guarantee of 2.65 lb/hr at maximum load.

The **$PM_{10}$ emission factor** is therefore:

(2.65 lb $PM_{10}$/hr)/(129 MM BTU/hr) = **0.0205 lb $PM_{10}$/MM BTU**

The applicant calculated a slightly higher emission rate of **0.0206 lb $PM_{10}$/MM BTU**.

The following stack data will be used to calculate the grain loading at standard conditions for full load auxiliary boiler operation to determine compliance with BAAQMD Regulation 6-310.3.

| | |
|---|---|
| $PM_{10}$ mass emission rate: | 2.65 lb/hr |
| typical flow rate: | 40,678 acfm |
| volume % water vapor: | 16.5 |
| stack temperature: | 325°F |

correcting flow rate to standard conditions:

(40,678 acfm)(1 – 0.165)(70 + 460/325 + 460)

Converting to grains/dscf:

(2 lb $PM_{10}$/hr)(1 hr/60 min)(7000 gr/lb)/(40,678 dscfm) = 0.0055 gr/dscf

Converting to 6% $O_2$ basis:

(0.0055 gr/dscf)[(20.95 - 6)/(20.95 – 3)] = 0.0046 gr/dscf @ 6% $O_2$

## SULFUR DIOXIDE EMISSION FACTOR

As in the case of the CTG and HRSG, the maximum sulfur content of natural gas will be limited to 0.25 gr/100 scf. The **$SO_2$ emission factor** for the auxiliary boiler is therefore also **0.0007 lb $SO_2$/MM BTU**.

This converts to a $SO_2$ mass emission rate of:

(0.0007 lb $SO_2$/MM BTU)(129 MM BTU/hr) = 0.09 lb $SO_2$/hr

## Toxic Air Contaminants

The following toxic air contaminant emission factors were used to calculate worst-case emissions rates used for air pollutant dispersion models that estimate the resulting increased health risk to the maximally exposed population. To ensure that the risk is properly assessed, the emission factors are conservative and may overestimate actual emissions.

### Table A-3
### TAC Emission Factors[a] for Gas Turbines and HRSG Duct Burners

| Contaminant | Emission Factor (lb/MM scf) |
|---|---|
| Acetaldehyde[c] | 6.86E-02 |
| Acrolein | 6.43E-03 |
| Ammonia[b] | 13.7 |
| Benzene[c] | 1.36E-02 |
| 1,3-Butadiene[c] | 1.27E-04 |
| Ethylbenzene | 1.79E-02 |
| Formaldehyde[c] | 1.10E-01 |
| Hexane | 2.59E-01 |
| Naphthalene | 1.66E-03 |
| PAHs[c] | |
| Anthracene | 3.38E-05 |
| Benzo(a)anthracene | 2.26E-05 |
| Benzo(a)pyrene | 1.39E-05 |
| Benzo(b)fluoranthrene | 1.13E-05 |
| Benzo(k)fluoranthrene | 1.10E-05 |
| Chrysene | 2.52E-05 |
| Dibenzo(a,h)anthracene | 2.35E-05 |
| Indeno(1,2,3-cd)pyrene | 2.35E-05 |
| Propylene | 7.70E-01 |
| Propylene Oxide[c] | 4.78E-02 |
| Toluene | 7.10E-02 |
| Xylene | 2.61E-02 |

[a]California Air Toxics Emission Factors (CATEF) Database as compiled by California Air Resources Board under the Air Toxics Hotspot Program

[b]based upon maximum allowable ammonia slip of 10 ppmv, dry @ 15% $O_2$ for A-1, A-2, and A-3 SCR Systems

[c]carcinogenic compound

### Table A-4 TAC Emission Factors[a] for Auxiliary Boiler

| Contaminant | Emission Factor (lb/MM scf) |
|---|---|

| | |
|---|---|
| Acetaldehyde[c] | 8.90E-03 |
| Acrolein | 8.00E-04 |
| Ammonia[b] | 4.8 |
| Benzene[c] | 4.31E-02 |
| Ethylbenzene | 2.00E-02 |
| Formaldehyde[c] | 2.21E-01 |
| Hexane | 1.30E-01 |
| Naphthalene | 3.00E-04 |
| PAHs[c] | 1.00E-04 |
| Propylene | 1.55E-01 |
| Toluene | 7.80E-03 |
| Xylene | 5.80E-03 |

[a]California Air Toxics Emission Factors (CATEF) Database as compiled by California Air Resources Board under the Air Toxics Hotspot Program

[b]based upon maximum allowable ammonia slip of 10 ppmv, dry @ 15% $O_2$ for A-4 SCR System

[c]carcinogenic compound

## Table A-5 TAC Emission Factors for 10-Cell Cooling Tower

| Toxic Air Contaminant | Maximum Concentration in Cooling Tower Return Water (ppm) | Emission Factor[a] (lb/hr) |
|---|---|---|
| Ammonia | 6 | 4.24E-03 |
| Arsenic[b] | 0.016 | 1.13E-05 |
| Cadmium[b] | 0.008 | 5.65E-06 |
| Trivalent chromium | 0.136 | 9.60E-05 |
| Copper | 0.032 | 2.26E-05 |
| Lead[b] | 0.0218 | 1.54E-05 |
| Mercury | 0.008 | 5.65E-06 |
| Nickel | 0.08 | 5.65E-05 |
| Silver | 0.08 | 5.65E-05 |
| Zinc | 0.056 | 3.95E-05 |

[a]based upon maximum drift rate of 0.0005% and operation of cooling tower at maximum water circulation rate of 282,300 gallons per minute; for example:

$NH_3$ = $(6/10^6)(0.000005)(282{,}300\ gal/min)(60\ min/hr)(8.337\ lb/gal)$
= 4.24E-03 lb/hr

[b]carcinogenic compound

## AMMONIA SLIP EMISSION FACTORS

### Combustion Gas Turbine & Heat Recovery Steam Generator

Each Gas Turbine/HRSG power train will exhaust through a common stack and be subject to a maximum ammonia exhaust concentration limit of 10 ppmvd @ 15% $O_2$.

| | |
|---|---|
| $NH_3$ emission concentration limit: | 10 ppmvd @ 15% $O_2$ |
| Dry gas flow rate (w/o duct burner): | 760,204 dscfm @ 13.4% $O_2$ by volume |
| Dry gas flow rate (w/duct burner): | 748,200 dscfm @ 10.32% $O_2$ by volume |

Correcting ammonia concentration to actual oxygen content at full load with duct burner firing:

(10 ppmvd)(20.95 – 10.32)/(20.95 – 15) = 17.87 ppmvd @ 10.32% $O_2$

The ammonia mass emission rate at full load with duct burner firing is therefore:

(17.87 ppmvd/$10^6$)(760,204 dscfm)(60 min/hr)(lb-mol/385.3 dscf)(17 lb $NH_3$/lb-mol) = **35.94 lb $NH_3$/hr**

Based upon the maximum combined heat input for a gas turbine/HRSG of 2,630.8 MM BTU/hr, this mass emission rate converts to the following emission factor:

(35.94 lb $NH_3$/hr)/(2,630.8 MM BTU/hr) = **0.0137 lb $NH_3$/MM BTU**
= **13.7 lb $NH_3$/MM scf**

Correcting ammonia concentration to actual oxygen content at full load without duct burner firing:

(10 ppmvd)(20.95 – 13.4)/(20.95 – 15) = 12.69 ppmvd @ 13.4% $O_2$

The ammonia mass emission rate at full load without duct burner firing is therefore:

(12.69 ppmvd/$10^6$)(760,204 dscfm)(60 min/hr)(lb-mol/385.3 dscf)(17 lb $NH_3$/lbmol) = **25.68 lb $NH_3$/hr**

Based upon the maximum heat input for a gas turbine of 1,898.8 MM BTU/hr, this mass emission rate converts to the following emission factor:

(25.68 lb $NH_3$/hr)/(1,898.8 MM BTU/hr) = **0.0137 lb $NH_3$/MM BTU**
= **13.7 lb $NH_3$/MM scf**

## Auxiliary Boiler

The S-7 Auxiliary Boiler abated by A-8 SCR System will be subject to a maximum ammonia exhaust concentration limit of 5 ppmvd @ 15% $O_2$.

| | |
|---|---|
| $NH_3$ emission concentration limit: | 10 ppmvd @ 3% $O_2$ |
| Dry gas flow rate @ full load: | 23,128 dscfm @ 2.5% $O_2$ by volume |

Correcting ammonia concentration to actual oxygen content at full load:

(10 ppmvd)(20.95 – 2.5)/(20.95 – 3) = 10.28 ppmvd @ 2.5% $O_2$

The ammonia mass emission rate at full load with duct burner firing is therefore:

(10.28 ppmvd/$10^6$)(23,128 dscfm)(60 min/hr)(lb-mol/385.3 dscf)(17 lb $NH_3$/lb-mol) = **0.62 lb $NH_3$/hr**

Based upon the maximum heat input for the auxiliary boiler of 129 MM BTU/hr, this mass emission rate converts to the following emission factor:

(0.62 lb $NH_3$/hr)/(129 MM BTU/hr) = **0.0048 lb $NH_3$/MM BTU**
= **4.8 lb $NH_3$/MM scf**

**Table A-6**
**Regulated Air Pollutant Emission Factors for Fire Pump Diesel Engine**

| Pollutant | Emission Factor | |
|---|---|---|
| | g/bhp-hr | lb/hr |
| Nitrogen Oxides (as $NO_2$) | 6[a] | 3.96 |
| Carbon Monoxide | 1[a] | 0.66 |
| Precursor Organic Compounds | 0.4[a] | 0.26 |
| Particulate Matter ($PM_{10}$) | 0.15[a] | 0.1 |
| Sulfur Dioxide | 0.17 | 0.1[b] |

[a] per 2000 CARB-Certification test results; Clarke Model JDFP-06WR; 300 bhp

[b]based upon maximum expected diesel fuel sulfur content of 0.05% by weight and calculated as follows:
(0.0005 lb S/lb fuel)(14.2 gal/hr)(6.88 lb/gal)(2 lb $SO_2$/lb S) = 0.1 lb $SO_2$/hr

**Table A-7**
**Toxic Air Contaminant Emission Factors for Fire Pump Diesel Engine**

| Toxic Air Contaminant | Emission Factor[a] (lb/MM BTU) |
|---|---|
| Benzene | 9.33E-04 |
| Toluene | 4.09E-04 |
| Xylenes | 2.85E-04 |
| Propylene | 2.58E-03 |
| 1,3-Butadiene | 3.91E-05 |
| Formaldehyde | 1.18E-03 |
| Acetaldehyde | 7.67E-04 |
| Acrolein | 9.25E-05 |
| Total PAHs | 1.68E-04 |

[a]AP-42 Table 3.3-2, "Speciated Organic Compound Emission Factors for Uncontrolled Diesel Engines"

# Appendix B

## Emission Calculations

Individual and combined heat input rate limits for the Gas turbines, HRSGs, and auxiliary boilers are given below in **Table B-1**. These are the basis of permit conditions limiting heat input rates.

### Table B-1 Maximum Allowable Heat Input Rates

| Source | MM BTU/hour-source | MM BTU/day-source | MM BTU/year-source |
|---|---|---|---|
| S-1, S-3, and S-5 Gas Turbines | 1,898.8 | 15,190.4[a] | 6,949,608[b] |
| S-1 CTG and S-2 HRSG<br>S-3 CTG and S-4 HRSG<br>S-5 CTG and S-6 HRSG | 2,630.8[c] | 63,139.2[d] | 13,417,080[e] |
| S-7 Auxiliary Boiler | 129 | 3,096[f] | 387,000[g] |
| Turbines and HRSGs combined | 7,892.4 | 189,417.6[h] | 61,100,064 |
| All Sources Combined | 8,021.4 | 190,449.6[i] | 61,487,064 |

[a]based upon specified maximum rated heat input of 1898.8 MM BTU/hr and 8 hour per day operation without duct burner firing

[b]based upon 3,660 hours of operation at full load (1898.8 MM BTU/hr), without duct burner firing

[c]maximum combined firing rate for each gas turbine and corresponding HRSG duct burner

[d]based upon maximum duct burner firing of 24 hours per day

[e]based upon maximum annual duct burner firing of 5,100 hr/year-HRSG; calculated as:

(5,100 hr/yr)(2,630.8 MM BTU/hr) = 13,417,080 MM BTU/year

[f]based upon 24 hr/day maximum operation @ full load

[g]based upon maximum 3000 hours of operation per year

[h]based upon 24 hr/day duct burner firing for all three power trains

[i]based upon combined 80 firing-hour limit for gas turbines and auxiliary boiler; calculated as follows:

(3 turbine/HRSG)(24 hrs)(2,630,8 MM BTU/hr) + (1 Aux. Boiler)(8 hr/day)(129 MM BTU/hr)
= 190,449.6 MM BTU/day

## B-1.0 Gas Turbine Start-Up and Shutdown Emission Rate Calculations

The maximum nitrogen oxide, carbon monoxide, and precursor organic compound mass emission rates from a gas turbine occur during start-up periods. The $PM_{10}$, sulfur dioxide, ammonia, and toxic compound emissions are a function of fuel use rate only and do not exceed typical full load emission rates during start-up. The $NO_x$, CO, and UHC (POC) emission rates shown in Table B-3 are Calpine estimates and were used for the permitted Sutter Power Project and the Metcalf Energy Center.

### Table B-2 Gas Turbine Start-Up Emission Rates (lb/start-up)

| Pollutant | Cold Start-Up[a] | Hot Start-Up[b] |
|---|---|---|
| $NO_x$ (as $NO_2$) | 240 | 80 |
| CO | 2,514[c] | 902 |
| UHC (as $CH_4$) | 48 | 16 |
| $PM_{10}$[d] | 33 | 11 |
| $SO_x$ (as $SO_2$)[e] | 4 | 1.33 |

[a]cold start not to exceed three hours

[b]hot start not to exceed one hour

[c]based upon emission rate of 838 lb CO/hour per Sutter Power Project and Metcalf Energy Center

[d]as a conservative estimate, based upon full load emission factor of 0.0058 lb $PM_{10}$/MM BTU and maximum heat input rate of 1,898.8 MM BTU/hr

[e]based upon full load emission factor of 0.0007 lb $SO_2$/MM BTU and maximum heat input rate of 1,898.8 MM BTU/hr

After considering source test data of Crockett Cogeneration gas turbine, it is assumed that turbine shutdown emission rates for $NO_x$, CO, and POC do not exceed full load emission rates. **Table B-4** is a comparison of baseload emission rates and shutdown emission rates based upon source test data.

### Table B-3 Gas Turbine Shutdown Emission Rates (lb/hr)

| Pollutant | Baseload Emission Rate[a] | Crockett Cogeneration Source Tests[b] |
|---|---|---|
| $NO_x$ | 17.2 | 5.2 |
| CO | 25.12 | 29.5 |
| UHC (as $CH_4$) | 2.65 | 2.6 |

[a]Calpine EAEC limits

[b]G.E. Frame 7F turbine; testing of gas turbine shutdown emission rates occurred June 1997

## B-2.0 Operating Scenarios and Regulated Air Pollutant Emissions for Gas Turbines and HRSGs

The Gas Turbine/HRSG air pollutant emission rates (except for $NO_x$) shown in **Table B-4** are the basis of permit condition limits and emission offset requirements and were also used as inputs for the ambient air quality impact analysis. To provide maximum operational flexibility, no limitations will be imposed on the type or quantity of turbine start-ups. Instead, the facility must comply with rolling consecutive twelve month mass emission limits at all times. The mass emission limits are based upon the emission estimates calculated for the following power plant operating envelope.

- 3,260 hours of baseload (100% load) operation per year for each gas turbine
- 5,100 hours of duct burner firing per HRSG per year with steam injection power augmentation at gas turbine combustors
- 250 one-hour hot start-ups per gas turbine per year
- 50 three-hour cold start-ups per gas turbine per year

### Table B-4 Maximum Annual Regulated Air Pollutant Emissions for Gas Turbines and HRSGs

| Source (Operating Mode) | $NO_2$ (lb/yr) | CO (lb/yr) | POC (lb/yr) | $PM_{10}$ (lb/yr) | $SO_2$ (lb/yr) | $H_2SO_4$ (lb/yr) |
|---|---|---|---|---|---|---|
| S-1, S-3, & S-5 Gas Turbines (750 total 1-hr hot start-ups) | 60,000 | 676,500 | 12,000 | 6,750 | 997.5 | 1,522.5 |
| S-1, S-3, & S-5 Gas Turbines (150 total 3-hr cold start-ups) | 36,000 | 377,100 | 7,200 | 4,050 | 598.5 | 913.5 |
| S-1, S-3, & S-5 Gas Turbines (9,780 total hours @ 100% load) | 134,279.4[a] | 163,423.8 | 25,917 | 88,020 | 13,007.4 | 19,853.4 |
| S-1 Gas Turbine & S-2 HRSG<br>S-3 Gas Turbine & S-4 HRSG<br>S-5 Gas Turbine & S-6 HRSG<br>(15,300 total hours w/duct burner firing and steam injection power augmentation) | 291,006[a] | 354,195 | 101,592 | 175,950 | 28,152 | 43,146 |
| Total Emissions (lb/yr) | 521,285.4 | 1,571,218.8 | 146,709 | 274,770 | 42,755.4 | 65,435.4 |
| (ton/yr) | **260.643** | **785.609** | **73.354** | **137.385[b,e]** | **21.378[c,e]** | **32.717[d,e]** |

[a]based upon an average NOx emission concentration of 2.0 ppmvd @ 15% $O_2$

[b]includes secondary particulate formation i.e., sulfate particulates

[c]worst-case estimate; assumes that all fuel-bound sulfur is converted to sulfur dioxide

[d]worst-case estimate; assumes that all fuel-bound sulfur is converted to sulfuric acid mist

[e]because fuel-bound sulfur must be divided among these pollutants, it is not physically possible for he $PM_{10}$, $SO_2$, and $H_2SO_4$ emission rates to reach these worst-case levels simultaneously

## B-3.0 Fire Pump Diesel Engine and Emergency Generator Emissions

## Table B-5 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 $NO_2$) | 6 | 3.96 | 396 |
| Carbon Monoxide | 1 | 0.66 | 66 |
| Precursor Organic Compounds | 0.4 | 0.26 | 26 |
| Particulate Matter[b] ($PM_{10}$) | 0.15 | 0.1 | 10 |
| Sulfur Dioxide | 0.17 | 0.1[b] | 10 |

[a]based upon 100 hours of operation per year for testing and maintenance

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

## Table B-6 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 | 0.185 |
| Toluene | 4.09E-04 | 0.08 |
| Xylenes | 2.85E-04 | 0.06 |
| Propylene | 2.58E-03 | 0.51 |
| 1,3-Butadiene | 3.91E-05 | 0.008 |
| Formaldehyde | 1.18E-03 | 0.25 |
| Acetaldehyde | 7.67E-04 | 0.24 |
| Acrolein | 9.25E-05 | 0.02 |
| Total PAHs | 1.68E-04 | 0.033 |

[a]based upon maximum fuel use rate of 1.988 MM BTU/hr and maximum 100 operating hours per year

## Table B-7 Regulated Air Pollutant Emissions for Natural Gas Fired Emergency Generator Engine

| Pollutant | Emission Factor | | Annual Emissions[a] |
|---|---|---|---|
| | g/bhp-hr | lb/hr | lb/yr |
| Nitrogen Oxides (as $NO_2$) | 0.82 | 2.76 | 276 |
| Carbon Monoxide | 2.6 | 8.75 | 875 |
| Precursor Organic Compounds | 0.44 | 1.5 | 150 |
| Particulate Matter ($PM_{10}$) | - | 0.11[b] | 11 |
| Sulfur Dioxide | 0.0024[c] | 0.008 | 0.8 |

[a]based upon 100 hours of operation per year for reliability-related activities per Regulation 9-8-330.2; engine rated at 1,529 bhp; maximum heat input rate of 11.5 MM BTU/hr

[b]based upon emission rate of 0.01 lb/MM BTU, AP-42, Table 3.2-2, "Uncontrolled Emission Factors for 4-Stroke, Lean-Burn Engines"

[c]assuming maximum sulfur content of 0.25 gr/100 scf and natural gas heat content of 1020 BTU/scf:

(0.25 gr S/100 scf)(2 lb $SO_2$/lb S)(1 lb/7000 gr)(1000 g/2.2 lb)(11,274.5 scf/hr)/(1,529 bhp)
= 0.0024 g/bhp-hr

## B-4.0 Cooling Tower $PM_{10}$ Emissions

It is conservatively assumed that all particulate matter emissions are $PM_{10}$.

Cooling tower circulation rate: 282,300 gpm
maximum total dissolved solids: 3400 ppm
Drift Rate: 0.0005 %

Water mass flow rate:

(282,300 gal/min)(60 min/hr)(8.34 lb/gal) = 141,262,920 lb/hr

Cooling Tower Drift:

(141,262,920 lb/hr)(0.000005) = 706.3 lb/hr

**$PM_{10}$** = (3400 ppm)(706.3 lb/hr)/($10^6$)
= 2.40 lb/hr
= 57.6 lb/day (24 hr/day operation)
= 21,024 lb/yr (8,760 operating hours per year)
= **10.512 ton/yr**

## B-5.0 Worst-Case Toxic Air Contaminant (TAC) Emissions

The maximum toxic air contaminant emissions resulting from the combustion of natural gas at the S-1, S-3, & S-5 Gas Turbines and S-2, S-4, & S-6 HRSGs are summarized in **Table B-8**. These emission rates were used as input data for the health risk assessment modeling and are based upon a maximum annual heat input rate of 20,366,688 MM BTU per year (19,947.8 MM scf/yr based upon a fuel HHV of 1021 BTU/scf) for each gas turbine/HRSG pair. The derivation of the emission factors is detailed in Appendix A.

**Table B-8**
**Worst-Case TAC Emissions for Gas Turbines and HRSGs**

| Toxic Air Contaminant | Emission Factor (lb/MM scf) | lb/yr-power train[a] | g/sec |
|---|---|---|---|
| Acetaldehyde[c] | 6.86E-02 | 1,368.4 | 1.97E-02 |
| Acrolein | 6.43E-03 | 128 | 1.84E-03 |
| Ammonia[b] | 13.7 | 273,285 | 3.93E+00 |
| Benzene[c] | 1.36E-02 | 271 | 3.90E-03 |
| 1,3-Butadiene[c] | 1.27E-04 | 2.53 | 3.64E-05 |
| Ethylbenzene | 1.79E-02 | 357 | 5.14E-03 |
| Formaldehyde[c] | 1.10E-01 | 2,194 | 3.16E-02 |
| Hexane | 2.59E-01 | 5,166 | 7.43E-02 |
| Naphthalene | 1.66E-03 | 33.1 | 4.76E-04 |
| PAHs[c] | | | |
| Anthracene | 3.38E-05 | 0.67 | 9.70E-06 |
| Benzo(a)anthracene | 2.26E-05 | 0.45 | 6.48E-06 |
| Benzo(a)pyrene | 1.39E-05 | 0.28 | 3.99E-06 |
| Benzo(b)fluoranthrene | 1.13E-05 | 0.23 | 3.24E-06 |
| Benzo(k)fluoranthrene | 1.10E-05 | 0.22 | 3.16E-06 |
| Chrysene | 2.52E-05 | 0.5 | 7.23E-06 |
| Dibenzo(a,h)anthracene | 2.35E-05 | 0.47 | 6.74E-06 |
| Indeno(1,2,3-cd)pyrene | 2.35E-05 | 0.47 | 6.74E-06 |
| Propylene | 7.70E-01 | 15,360 | 2.21E-01 |
| Propylene Oxide[c] | 4.78E-02 | 954 | 1.37E-02 |
| Toluene | 7.10E-02 | 1,416 | 2.04E-02 |
| Xylene | 2.61E-02 | 521 | 7.49E-03 |

[a]from each gas turbine/HRSG power train (S-1 & S-2, S-3 & S-4, and S-5 & S-6)

[b]based upon the worst-case ammonia slip from the SCR system of 10 ppmvd @ 15% $O_2$

[c]carcinogenic compounds

The maximum toxic air contaminant emissions resulting from the combustion of natural gas at the S-7 Auxiliary Boiler are summarized in **Table B-9**. These emission rates were used as input data for the health risk assessment modeling and are based upon a maximum annual heat input rate of 387,000 MM BTU per year (387 MM scf/yr based upon a fuel HHV of 1022 BTU/scf).

## Table B-9 Worst-Case TAC Emissions for Auxiliary Boiler

| Air Contaminant | Emission Factor (lb/MM scf) | lb/yr | g/s |
|---|---|---|---|
| Acetaldehyde[c] | 8.90E-03 | 3.44 | 4.92E-05 |
| Acrolein | 8.00E-04 | 0.3 | 4.45E-06 |
| Ammonia[b] | 4.8 | 1,857.6 | 2.67E-02 |
| Benzene[c] | 4.31E-02 | 16.7 | 2.40E-04 |
| Ethylbenzene | 2.00E-02 | 7.74 | 1.11E-04 |
| Formaldehyde[c] | 2.21E-01 | 85.5 | 1.23E-03 |
| Hexane | 1.30E-01 | 50.3 | 7.24E-04 |
| Naphthalene | 3.00E-04 | 0.12 | 1.67E-06 |
| Total PAHs[c] | 1.00E-04 | 0.04 | 5.57E-07 |
| Propylene | 1.55E-01 | 60 | 8.63E-04 |
| Toluene | 7.80E-03 | 3 | 4.34E-05 |
| Xylene | 5.80E-03 | 2.2 | 3.23E-05 |

The projected toxic air contaminant emissions from the exempt 10-cell cooling tower are summarized in **Table B-10**. The emissions are based upon an water circulation rate of 282,300 gpm and 8,760 hours of operation per year.

## Table B-10 Worst-Case TAC Emissions for 19-Cell Cooling Tower

| Toxic Air Contaminant | Emission Factor (lb/hr) | Annual Emission Rate (lb/yr) | Risk Screening Trigger Level (lb/yr) |
|---|---|---|---|
| Ammonia | 4.24E-03 | 37.1 | 19,300 |
| Arsenic[a] | 1.13E-05 | 0.1 | 0.024 |
| Cadmium[a] | 5.65E-06 | 0.05 | 0.046 |
| Trivalent chromium | 9.60E-05 | 0.84 | None specified |
| Copper | 2.26E-05 | 0.2 | 463 |
| Lead[a] | 1.54E-05 | 0.14 | 29 |
| Mercury | 5.65E-06 | 0.05 | 57.9 |
| Nickel | 5.65E-05 | 0.5 | 0.73 |
| Silver | 5.65E-05 | 0.5 | N/S[b] |
| Zinc | 3.95E-05 | 0.35 | 6,760 |

[a]carcinogenic compound

## B-6.0 Maximum Facility Emissions

The maximum annual facility regulated air pollutant emissions for the proposed gas turbines and HRSGs are shown in **Table B-11**. The total permitted emission rates shown below are the basis of permit condition limits and emission offset requirements, if applicable.

## Table B-11 Maximum Annual Facility Regulated Air Pollutant Emissions (ton/yr)

| Source | $NO_2$ | CO | POC | $PM_{10}$ | $SO_2$ | $H_2SO_4$ |
|---|---|---|---|---|---|---|
| S-1 CTG and S-2 HRSG[a] | 86.881 | 261.87 | 24.45 | 45.795 | 7.13 | 10.9 |
| S-3 CTG and S-4 HRSG[a] | 86.881 | 261.87 | 24.45 | 45.795 | 7.13 | 10.9 |
| S-5 CTG and S-6 HRSG[a] | 86.881 | 261.87 | 24.45 | 45.795 | 7.13 | 10.9 |
| Sub-Total | **260.643** | **785.609** | **73.354** | **137.385** | **21.378** | **32.717** |
| S-7 Auxiliary Boiler | 2.205 | 7.5 | 0.9 | 3.975 | 0.135 | 0.21 |
| S-8 Cooling Tower | 0 | 0 | 0 | 10.512 | 0 | 0 |
| S-9 Diesel Fire Pump Engine | 0.218 | 0.131 | 0.036 | 0.01 | 0.006 | 0 |
| S-10 Emergency Generator | 0.138 | 0.438 | 0.075 | 0.005 | negligible | negligible |
| Total Facility Emissions | **263.204[b]** | **793.678** | **74.365** | **151.887** | **21.52** | **32.927** |

[a]includes gas turbine start-up and shutdown emissions

[b]per applicant's request, permit conditions will limit annual facility NOx emissions from permitted sources to 263 tons per year, based upon an average $NO_x$ emission concentration of 2.0 ppmvd @ 15 % $O_2$

## Table B-12 Baseload Air Pollutant Emission Rates for Gas Turbines, HRSGs, and Auxiliary Boiler

### (Excluding Gas Turbine Start-up Emissions)

| | $NO_2$ | CO | POC | $PM_{10}$ | $SO_2$ |
|---|---|---|---|---|---|
| S-1, S-3, and S-5 Gas Turbines[a] | | | | | |
| lb/hr-source | 13.73 | 16.71 | 2.65 | 9 | 1.33 |
| lb/day-source | 329.5 | 401 | 63.6 | 216 | 31.92 |
| S-1 & S-2, S-3 & S-4, and S-5 & S-6 Gas Turbine/HRSG Power Train | | | | | |
| lb/hr-power train | 19.02 | 23.15 | 6.64 | 11.5 | 1.84 |
| lb/day-power train[b] | 456.5 | 555.6 | 127.4 | 276 | 40.1 |
| S-7 Auxiliary Boiler | | | | | |
| lb/hr | 1.47 | 5.0 | 0.6 | 2.65 | 0.09 |
| lb/day[c] | 35.3 | 120 | 14.4 | 63.6 | 2.2 |
| lb/yr[d] | 4,410 | 15,000 | 1,800 | 7,950 | 270 |

[a]based upon maximum heat input rate of 1898.8 MM BTU/hr for each gas turbine

[b]based upon a maximum combined heat input rate for each gas turbine/HRSG power train of 2,630.8 MM BTU/hr and maximum 24 hours per day duct burner firing

[c]based upon maximum 24 hr/day operation at full load

[d]based upon 3000 hr/yr operation

The maximum daily regulated air pollutant emissions per source including gas turbine start-up emissions are shown in **Table B-13**.

## Table B-13
## Maximum Daily Regulated Air Pollutant Emissions per Power Train (lb/day)

| Source (operating mode) | $NO_2$ | CO | POC | $PM_{10}$ | $SO_2$ |
|---|---|---|---|---|---|
| Gas Turbine (3-hr Cold Start-up) | 240 | 2,514 | 48 | 27 | 4 |
| Gas Turbine & HRSG (20 hours Full load w/Duct Burner Firing and steam injection power augmentation) | 380 | 463 | 132.8 | 230 | 36.8 |
| Gas Turbine (1-hr Hot Start-up) | 80 | 902 | 16 | 9 | 1.3 |
| Total | **700** | **3,879** | **196.8** | **266 (276)[b]** | **42.1 (44.2)[b]** |

[a]based upon one 1-hour hot start-up, one 3-hour cold start-up, and 20 hours of full load operation with duct burner firing @ 2,630.8 MM BTU/hr with steam injection power augmentation. For example, CO emissions are calculated as follows:

(902 lb/hr)(1 hr/hot SU) + (838 lb/hr)(3 hr/cold SU) + (23.15 lb CO/hr)(24 hr/day) = 3,879 lb CO/day

[b]highest emissions for these pollutants actually occur during 24-hr per day operation of all three gas turbines at full load with duct burner firing; calculated as follows:

$PM_{10}$ = (11.5 lb/hr)(24 hr/day) = 276 lb/day

$SO_2$ = (1.84 lb/hr)(24 hr/day) = 44.2 lb/day

**Table B-14** summarizes the worst-case daily regulated air pollutant emissions from permitted sources. These are the basis of permit condition daily mass emission limits.

## Table B-14 Worst-Case Daily Regulated Air Pollutant Facility Emissions from Permitted Sources (lb/day)

| Source (Operating Mode) | $NO_2$ | CO | POC | $PM_{10}$ | $SO_2$ |
|---|---|---|---|---|---|
| S-1 Gas Turbine (Cold Start-up) | 240 | 2,514 | 48 | 27 | 4 |
| S-1 Gas Turbine & S-2 HRSG (20 hours @ Full load w/Duct Burner Firing and steam injection power augmentation) | 380 | 463 | 132.8 | 230 | 36.8 |
| S-1 Gas Turbine (Hot Start-up) | 80 | 902 | 16 | 9 | 1.3 |
| S-3 Gas Turbine (Cold Start-up[a]) | 240 | 2,514 | 48 | 27 | 4 |
| S-3 Gas Turbine & S-4 HRSG (18 hours @ Full load w/Duct Burner Firing and steam injection power augmentation) | 342 | 416.7 | 119.5 | 207 | 33.1 |
| S-3 Gas Turbine (Hot Start-up) | 80 | 902 | 16 | 9 | 1.3 |
| S-5 Gas Turbine (Cold Start-up[a]) | 240 | 2,514 | 48 | 27 | 4 |
| S-5 Gas Turbine & S-6 HRSG (16 hours @ Full load w/Duct Burner Firing and steam injection power augmentation) | 304 | 370.4 | 106.2 | 184 | 29.4 |
| S-5 Gas Turbine (Hot Start-up) | 80 | 902 | 16 | 9 | 1.3 |
| Sub-Total: Gas Turbines/HRSGs | **1,986** | **11,498.1** | **550.5** | **729 (828[d])** | **115.2 (132.5[d])** |
| S-7 Auxiliary Boiler | 35.3 | 120 | 14.4 | 63.6 | 2.2 |
| S-8 Cooling Tower | 0 | 0 | 0 | 57.6 | 0 |
| S-9 Emergency Generator[b] | 2.76 | 8.75 | 1.5 | 0.11 | 0.8 |
| S-10 Diesel Fire Pump Engine[b] | 6.46 | 6.78 | 2.91 | 0.05 | 0.01 |
| Total[c] | **2,030.5** | **11,633.6** | **569.3** | **949.4[e]** | **135.5[e]** |

[a]turbine start-ups will stagger by two hours

[b]based upon maximum of 1 hour of exercising per day

[c]because the generator and fire pump will not be exercised on the same day, total reflects higher emission rate for each pollutant

[d]highest emissions actually occur during 24-hr per day operation of all three gas turbines at full load with duct burner firing; calculated as follows:

$PM_{10}$ = (3 turbine/HRSG)(11.5 lb/hr)(24 hr/day) = 828 lb/day

$SO_2$ = (3 turbine/HRSG)(1.84 lb/hr)(24 hr/day) = 132.5 lb/day

[e]reflects emission rates calculated in footnote d

# B-7.0 Modeling Emission Rates

The $NO_2$ emission rates shown in **Table B-15** were used to model the air quality impacts of the EAEC to determine compliance with State and Federal annual ambient air quality standards for $NO_2$. A screening impact analysis of gas turbine/HRSG duct burner emission rates and stack gas characteristics showed that the worst-case annual average impacts for $NO_2$ occur under the following equipment operating scenario.

### Table B-15 $NO_2$ Emission Rates for Worst-Case Annual-Average Impacts

| Source (Operating Mode) | $NO_2$ | | |
|---|---|---|---|
| | lb/yr | lb/hr | g/s |
| Gas Turbine (250 hot start-ups/turbine) | 20,000 | | |
| Gas Turbine (50 cold start-ups/turbine) | 12,000 | | |
| Gas Turbine (3,260 firing hours/turbine @ 1,898.8 MM BTU/hr) | 44,831.5 | | |
| Gas Turbine and associated HRSG (5,100 hours/turbine w/duct burner firing @ 2,630.8 MM BTU/hr) | 97,104 | | |
| Each CTG & HRSG Total Emissions | 173,935.5 | 19.856 | 2.502 |
| S-7 Auxiliary Boiler (3000 hr/yr @ 129 MMBTU/hr) | 4,410 | 0.503 | 0.063 |
| S-9 Fire Pump Diesel Engine (100 firing hours/year) | 436 | 0.05 | 6.27E-03 |
| S-10 Emergency Generator (200 firing hours/year) | 1,292 | 0.148 | 0.0186 |

The $PM_{10}$ and $SO_2$ emission rates shown in **Table B-16** were used to model the corresponding air quality impacts to determine compliance with the State and Federal annual ambient air quality standards for $PM_{10}$ and $SO_2$. Based upon a screening impact analysis of gas turbine/HRSG duct burner emission rates and stack gas characteristics, it was determined that the worst-case annual average impacts for $PM_{10}$ and $SO_2$ occur under the equipment operating scenario shown below.

### Table B-16 $PM_{10}$ and $SO_2$ Emission Rates for Worst-Case Annual-Average Impacts

| Source (Operating Mode) | $PM_{10}$ | | | $SO_2$ | | |
|---|---|---|---|---|---|---|
| | lb/yr | lb/hr | g/s | lb/yr | lb/hr | g/s |
| Gas Turbine (250 hot start-ups) | 2,250 | | | 332.5 | | |
| Gas Turbine (50 cold start-ups) | 1,350 | | | 199.5 | | |
| Gas Turbine (3,260 hours @ 100% load) | 29,340 | | | 4,335.8 | | |
| Gas Turbine & HRSG (5,100 hours w/duct burner firing @ 2,630.8 MM BTU/hr) | 58,650 | | | 9,384 | | |
| Gas Turbine & HRSG Total Emission | 91,590 | 10.5 | 1.32 | 14,251.8 | 16.572 | 2.09 |
| S-7 Auxiliary Boiler (3000 hr/yr @ 129 MMBTU/hr) | 7,950 | 0.9075 | 0.114 | 270 | 0.03 | 0.0039 |
| S-8 19-Cell Cooling Tower | 21,024 | 2.40 | 1.59E-02[a] | 0 | 0 | 0 |
| S-9 Fire Pump Diesel Engine (100 firing hours/year) | 19 | 2.17E-03 | 2.73E-04 | 1.3 | 1.48E-03 | 1.87E-04 |
| S-10 Emergency Generator (200 firing hours/year) | 104 | 1.19E-02 | 1.50E-03 | 1.8 | 2.05E-04 | 2.59E-05 |

[a]emission rate per cell

The $PM_{10}$ and $SO_2$ emission rates shown in **Table B-17** were used to model the corresponding air quality impacts to determine compliance with the state and federal 24-hour ambient air quality standards for $PM_{10}$ and $SO_2$. Based upon a screening impact analysis of gas turbine/HRSG duct burner emission rates and stack gas characteristics, it

was determined that the worst-case impacts for $PM_{10}$ and $SO_2$ over a 24-hour averaging period occur under the equipment operating scenario shown below.

### Table B-17 $PM_{10}$ and $SO_2$ Emission Rates for Worst-Case 24-hour Average Impacts

| Source (Operating Mode) | $PM_{10}$ | | | $SO_2$ | | |
|---|---|---|---|---|---|---|
| | lb/day | lb/hr | G/s | lb/day | lb/hr | g/s |
| S-1, S-3, & S-5 Gas Turbines (100% load w/o duct burner firing @ 1,898.8 MM BTU/hr; 98oF) | 216 | 9 | 1.134 | | | |
| S-1, S-3, & S-5 Gas Turbines (70% load @ 1,479.4 MM BTU/hr; 45oF) | | | | 24.85 | 1.036 | 0.131 |
| S-7 Auxiliary Boiler (Max. 8 hr day @ 129 MM BTU/hr) | 21.2 | 0.883 | 0.113 | 0.72 | 0.03 | 0.00378 |
| S-8 19-Cell Cooling Tower | 57.6 | 2.40 | 1.59E-02[a] | 0 | 0 | 0 |
| S-9 Fire Pump Diesel Engine[b] | - | - | - | 0.13 | 0.13 | 1.64E-02 |
| S-10 Emergency Generator[b] | 0.52 | 0.52 | 6.55E-02 | - | - | - |
| Total: | 295.3 | | | 25.7 | | |

[a]emission rate per cell

[b]based upon 1 hour of full-load operation per 24-hour period; fire pump and generator will not operate within same 24-hour period

The carbon monoxide emission rates shown in **Table B-18** were used to model the corresponding air quality impacts to determine compliance with the State and Federal 8-hour ambient air quality standards for CO. Based upon a screening impact analysis of gas turbine/HRSG duct burner emission rates and stack gas characteristics, it was determined that the worst-case impacts for CO over an 8-hour averaging period occur under the equipment operating scenario shown below. Although each turbine/HRSG power train will be subject to a CO emission limit of 4 ppmvd, the modeling emission rates are based upon a CO emission concentration of 6 ppmvd.

### Table B-18 CO Emission Rates for Worst-Case 8-hour Average Impacts

| Source (Operating Mode) | CO | | |
|---|---|---|---|
| | lb | lb/hr | g/s |
| Each Gas Turbine (3-hour Cold Start-up) | 2,514 | | |
| Each Gas Turbine & HRSG (Full Load Operation w/Duct Burner Firing[a]) | 167.2 | | |
| Total: | 2,681.2 | 335.2 | 42.23 |
| S-10 Emergency Generator (1 hr of full-load operation per 8-hr period) | 3 | 0.375 | 4.7E-02 |
| S-9 Fire Pump Diesel Engine (not in operation) | 0 | 0 | 0 |
| S-7 Auxiliary Boiler (8 hr @ 129 MM BTU/hr) | 40 | 5 | 0.63 |

[a]based upon worst-case assumption of 5 hours of operation @ 98°F at maximum combined heat input of 2,533.8 MM BTU/hr; actual start-ups will be staggered by 2 hours

The $NO_2$, CO, and $SO_2$ emission rates shown in Table **B-19** were used to model the corresponding air quality impacts to determine compliance with the State and Federal 1-hour ambient air quality standards for $NO_2$, CO, and $SO_2$. Based upon a screening impact analysis of gas turbine/HRSG duct burner emission rates and stack gas characteristics, it was determined that the worst-case impacts for CO and $NO_2$ over a 1-hour period occur when both

turbines are operating at full load with duct burner firing at an ambient temperature of 90°F. The emergency generator and fire pump will not be excercised on the same day. Therefore, the higher emission rate for each pollutant of the two engines is used for modeling. Although each turbine/HRSG power train will be subject to a CO emission limit of 4 ppmvd, the modeling emission rates are based upon a CO emission concentration of 6 ppmvd.

**Table B-19**
**$NO_2$, CO, and $SO_2$ Emission Rates for Worst-Case 1-hour Average Impacts**

| Source (Operating Mode) | $NO_2$ | | CO | | $SO_2$ | |
|---|---|---|---|---|---|---|
| | lb/hr | g/s | lb/hr | g/s | lb/hr | g/s |
| S-1 Gas Turbine & S-2 HRSG (100% Load w/Duct Burner Firing and steam injection power augmentation @ 98oF; 2,533.8 MM BTU/hr) | 22.9 | 2.89 | 33.45 | 4.214 | 1.77 | 0.225 |
| S-3 Gas Turbine & S-4 HRSG (100% Load w/Duct Burner Firing and steam injection power augmentation @ 98oF; 2,533.8 MM BTU/hr) | 22.9 | 2.89 | 33.45 | 4.214 | 1.77 | 0.225 |
| S-5 Gas Turbine & S-6 HRSG (100% Load w/Duct Burner Firing and steam injection power augmentation @ 98oF; 2,533.8 MM BTU/hr) | 22.9 | 2.89 | 33.45 | 4.214 | 1.77 | 0.225 |
| S-7 Auxiliary Boiler | 1.47 | 0.185 | 5 | 0.63 | 0.09 | 0.0113 |
| S-10 Emergency Generator | n/a | n/a | 6.78 | 0.854 | n/a | n/a |
| S-9 Fire Pump Diesel Engine | 4.36 | 0.55 | n/a | n/a | 0.13 | 0.0164 |

## B-8.0 Maximum Facility Emissions During Commissioning Period

**Table B-20** summarizes the worst-case 1-hour and 8-hour emission rates for the EAEC during the commissioning period, when the SCR systems will not be installed and operational. These emission rates were used as inputs in air quality impact models that were used to determine if the EAEC would contribute to an exceedance of the 1-hour State $NO_2$ ambient air quality standard, the 1-hour State and Federal CO standards, and the 8-hour State and Federal CO standards during the commissioning of the gas turbines, HRSGs, and related equipment. It is assumed that only one gas turbine will be commissioned at one time.

**Table B-20**
**Worst-Case Short-Term $NO_2$ and CO Emissions from Gas Turbines and Auxiliary Boiler during Commissioning Period**

| | $NO_2$ | | CO | |
|---|---|---|---|---|
| 1-hour Emission Rates | lb/hr | g/s | lb/hr | G/s |
| S-1 Gas Turbine | 362[a] | 45.61 | 902[b] | 113.7 |
| S-3 Gas Turbine | 362[a] | 45.61 | 902[b] | 113.7 |
| S-5 Gas Turbine | 362[a] | 45.61 | 902[b] | 113.7 |
| S-7 Auxiliary Boiler | 33 | 4.158 | 22 | 2.77 |
| 8-hour Emission Rates[c] | | | | |
| S-1 CTG & S-2 HRSG | n/a | n/a | 343.5 | 43.28 |
| S-3 CTG & S-4 HRSG | n/a | n/a | 343.5 | 43.28 |
| S-3 CTG & S-4 HRSG | n/a | n/a | 343.5 | 43.28 |
| S-7 Auxiliary Boiler | n/a | n/a | 22 | 2.77 |

[a]based upon a conservative exhaust gas $NO_x$ emission concentration of 50 ppmvd @ 15% $O_2$ for each turbine when operating without abatement by the SCR system; twice the turbine vendor unabated guaranteed emission rate of 25 ppmvd @ 15 % $O_2$

[b]equal to the turbine hot start-up CO hourly emission rate

[c]based upon one 3-hour cold start-up, followed by 5 hours of 100% load operation of CTG and HRSG at the maximum combined heat input rate of 2,630.8 MM BTU/hr; see Table B-17 for further detail

# Appendix C

## Emission Offsets

### Table C-1 Emission Offset Summary

| | $NO_x$ | CO | POC | $PM_{10}$ | $SO_2$ |
|---|---|---|---|---|---|
| BAAQMD Calculated New Source Emission Increases[a] (ton/yr) | 263.204 | 793.678 | 74.365 | 151.887 | 21.52 |
| Proposed New Source Annual Emission Limits[b] (ton/yr) | 263 | 793.6 | 73.7 | 148 | 21.33 |
| Offset Requirement Triggered | Yes | n/a | Yes | Yes | No |
| Offset Ratio | 1.15:1.0[c] | n/a | 1.15:1.0[c] | 1.0:1.0[d] | N/a |
| Offsets Required (tons) | **302.450** | **0** | **84.755** | **148** | **0** |
| ERCs to be Provided (tons) | **302.450** | **0** | **84.755** | **0[e]** | **444[e]** |

[a]sum of Gas Turbine (S-1, S-3, and S-5), HRSG (S-2, S-4, and S-6), S-7 Auxiliary Boiler, S-8 Cooling Tower, S-9 Fire Pump Diesel Engine, and S-10 Emergency Generator emission increases; see Appendix B, Table B-11

[b]Calpine's emission estimates

[c]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

[d]pursuant to District Regulation 2-2-303

[e]pursuant to Regulation 2-2-303.1, applicant has control of sufficient offsets to provide $SO_2$ ERCs to offset the $PM_{10}$ emission increases at a ratio of 3.0:1.0; interpollutant trade and ratio subject to EPA review and concurrence

## Interpollutant offset ratio ($SO_2$ for $PM_{10}$):

The applicant has requested permission to provide $SO_2$ offsets in lieu of $PM_{10}$. This substitution is authorized by District Regulation 2-2-303.1. Sulfur Dioxide is a *precursor* for the formation of *fine particulate* (in the form of sulfates) in the atmosphere. Not all emitted $SO_2$ contributes to the formation of particulate, however. The District evaluates each proposed interpollutant trade to determine the ratio needed to provide a net air quality benefit as defined in District Regulation 2-2-224.

The methodology used by the District to determine net air quality benefit involves two steps. First, the area impacted by the new source and the area impacted by the offsetting source are determined. Second, the amount of $SO_2$ necessary to provide an air quality benefit equivalent to the required $PM_{10}$ offsets is determined.

If the proposed project has a *direct impact* that is *significant*, the area where the project has a significant impact *is* the impact area (District Regulation 2-2-219). In that case, the area impacted by the offsetting source must include the area where the proposed source has a significant impact; otherwise, the proposed offsets cannot have a net air quality benefit.

If the proposed project has a direct impact that is *not* significant, the *region* is the general area impacted by the proposed source. Because the offsetting source also impacts the region, a showing of a net air quality benefit for the region as a whole satisfies the requirement of District Regulation 2-2-303.1.

The East Altamont Energy Center project has a direct impact for PM10 that is *not* significant (See the attached analysis). As a result, the general area impacted by both sources is the region. The proposed offsets must therefore result in a net air quality benefit for the region as a whole.

Once it has been determined that the offsetting source impacts the same general area as the proposed source, the District must determine the appropriate offset ratio. The amount of $PM_{10}$ that forms as a result of $SO_2$ emissions is determined by measuring the amount of sulfate in collected ground-level particulates, and the amount of $SO_2$ known to have been emitted in the area. The District has determined that this ratio, measured at the site of the proposed source, is 2.0:1.0. The District has determined that this ratio, measured at the site of the offsetting source, is 3.0:1.0.

The District has determined that the appropriate ratio for this project is 3:0:1.0 (see the attached analysis). This offset proposal will have the following impacts:

- A significant benefit in the area directly impacted by the offsetting source (Rodeo).
- A net air quality benefit in the general area impacted by the proposed source (the region)
- No significant impact in the area directly impacted by the proposed source (East Altamont).

The proposed $SO_2$ offsets will result in a net air quality benefit, and may be used to offset the project's $PM_{10}$ increases, at a ratio of 3.0:1.0.

# Appendix D

## Health Risk Assessment

As a result of the combustion of natural gas at the proposed Gas Turbines and HRSGs and the presence of dissolved solids (heavy metals) in the cooling tower water, the proposed East Altamont Energy Center will emit the toxic air contaminants summarized in Table 2, "Maximum Facility Toxic Air Contaminant (TAC) Emissions". In accordance with the requirements of CEQA, the BAAQMD Risk Management Policy, and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing the air pollutant dispersion model ISCST3 and the multi-pathway cancer risk and hazard index model ACE.

The public health impact of the carcinogenic compound emissions is quantified through the increased carcinogenic risk to the maximally exposed individual (MEI) over a 70-year exposure period. A multi-pathway risk assessment was conducted that included both inhalation and noninhalation pathways of exposure, including the mother's milk pathway. Pursuant to the BAAQMD Risk Management Policy, a project which results in an increased cancer risk to the MEI of less than one in one million over a 70 year exposure period is considered to be not significant and is therefore acceptable.

The public health impact of the noncarcinogenic compound emissions is quantified through the chronic hazard index, which is the ratio of the expected concentration of a compound to the acceptable concentration of the compound. When more than one toxic compound is emitted, the hazard indices of the compounds are summed to give the total hazard index. The acute hazard index quantifies the magnitude of the adverse health affects caused by a brief (no more than 24 hours) exposure to a chemical or group of chemicals. The chronic hazard index quantifies the magnitude of the adverse health affects from prolonged exposure to a chemical caused by the accumulation of the chemical in the human body. The worst-case assumption is made that the exposure occurs over a 70-year period. Per the BAAQMD Toxic Risk Management Policy, a project with a total hazard index of 1.0 or less is considered to be not significant and the resulting impact on public health is deemed acceptable.

In anticipation of pending amendments to District Regulation 2, Rule 1 and Rule 2, a health risk screening was performed to determine the impact of diesel exhaust particulate from the standby fire pump diesel engine. Because the location of maximum impact for the diesel engine does not coincide with the locations of maximum impact for the other sources, the total combined carcinogenic risk for the facility does not exceed 1.0 in one million. As shown in Table D-1, the increased carcinogenic risk was found to be less than one in one million and is therefore considered to be not significant.

The results of the health risk assessment performed by the applicant and reviewed by the District Toxics Evaluation Section staff are summarized in **Table D-1**.

## Table D-1
## Health Risk Assessment Results

| Source | Multi-pathway Carcinogenic Risk (risk in one million) | Chronic Hazard Index | Acute Hazard Index[a] |
|---|---|---|---|
| Gas Turbines, HRSGs, Auxiliary Boiler, Emergency Generator, and Cooling Tower[b] | 0.178 | -- | -- |
| Fire Pump Diesel Engine | 0.913 | -- | -- |
| Maximum Facility Risk: | 0.937[c] | 0.008 | 0.378 |

[a]included for informational purposes only; the BAAQMD TRMP does not require an assessment of the impact due to short-term (< 24 hour) exposure to non-carcinogenic toxic air contaminants

[b]numbers represent combined risk from all sources

[c]because the location of maximum impact for the diesel engine does not coincide with the locations of maximum impact for the other sources, the carcinogenic risk numbers do not add directly to determine the maximum facility cancer risk shown

In accordance with the BAAQMD Toxic Risk Management Policy (TRMP), the increased carcinogenic risk and chronic hazard index attributed to this project are each considered to be not significant since they are each less than 1.0. The BAAQMD TRMP does not require an assessment the impact due to short-term (< 24 hour) exposure to non-carcinogenic toxic air contaminants, which is expressed as the acute hazard index.

Based upon the results given in Table D-1, the East Altamont Energy Center project is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy.

# Appendix E

## SUMMARY OF AIR QUALITY IMPACT ANALYSIS FOR THE EAST ALTAMONT CENTER

*December 18, 2001*

## BACKGROUND

The East Altamont Energy Center, LLC has submitted a permit application (# 2589) for a proposed 1100-MW combined cycle power plant. The facility is to be composed of three natural gas-fired turbines with heat recovery steam generators, one steam turbine and supplemental burners (duct burners), a 19-cell cooling tower, a natural gas fueled emergency generator and a diesel fire pump engine. The proposed project will result in an increase in air pollutant emissions of $NO_2$, CO, $PM_{10}$ and $SO_2$ triggering regulatory requirements for an air quality impact analysis.

## AIR QUALITY IMPACT ANALYSIS REQUIREMENTS

Requirements for air quality impact analysis are given in the District's New Source Review (NSR) Rule: Regulation 2, Rule 2.

The criteria pollutant annual worst case emission increases for the Project are listed in Table I, along with the corresponding significant emission rates for air quality impact analysis.

Table I
Comparison of proposed project's annual worst case emissions
to significant emission rates for air quality impact analysis

| Pollutant | Proposed Project's Emissions (tons/year) | Significant Emission Rate (tons/year) (Reg-2-2-304 to 2-2-306) | EPA PSD Significant Emission Rates for major stationary sources (tons/year) | Significant emission rate? |
|---|---|---|---|---|
| $NO_x$ | 261.8 | 100 | 40 | yes |
| CO | 916.7 | 100 | 100 | yes |
| $PM_{10}$ | 148.0 | 100 | 15 | yes |
| $SO_2$ | 21.3 | 100 | 40 | no |

Table I shows the proposed project emissions and the pollutant significant emission levels for nitrogen oxides ($NO_x$), carbon monoxide (CO), respirable particulate matter ($PM_{10}$) and sulfur dioxide ($SO_2$). The table shows that the $NO_2$, CO and $PM_{10}$ ambient impacts from the project all exceed the significance level and must be modeled. The detailed requirements for an air quality

impact analysis for these pollutants are given in Sections 304, 305 and 306 of the District's NSR Rule and 40 CFR 51.166 of the Code of Federal Regulations.

The District's NSR Rule also contains requirements for certain additional impact analyses associated with air pollutant emissions. An applicant for a permit that requires an air quality impact analysis must also, according to Section 417 of the NSR Rule, provide an analysis of the impact of the source and source-related growth on visibility, soils and vegetation.

## AIR QUALITY IMPACT ANALYSIS SUMMARY

The required contents of an air quality impact analysis are specified in Section 414 of Regulation 2 Rule 2. According to subsection 414.1, if the maximum air quality impacts of a new or modified stationary source do not exceed significance levels for air quality impacts, as defined in Section 2-2-233, no further analysis is required. (Consistent with EPA regulations, it is assumed that emission increases will not interfere with the attainment or maintenance of AAQS, or cause an exceedance of a PSD increment if the resulting maximum air quality impacts are less than specified significance levels). If the maximum impact for a particular pollutant is predicted to exceed the significance impact level, a full impact analysis is required involving estimation of background pollutant concentrations and, if applicable, a PSD increment consumption analysis. EPA also requires a Class I increment analysis of any PSD source which increases $NO_2$ or $PM_{10}$ concentrations by 1 $\mu g/m^3$ or more (24-hour average) in a Class I area.

### Air Quality Modeling Methodology

Maximum ambient concentrations of $NO_2$, CO and $PM_{10}$ were estimated for various plume dispersion scenarios using established modeling procedures. The plume dispersion scenarios addressed include simple terrain impacts (for receptors located below stack height), complex terrain impacts (for receptors located at or above stack height), impacts due to building downwash, and impacts due to inversion breakup fumigation.

Emissions from the turbines will be exhausted from three 175 foot exhaust stacks and the auxiliary boiler will be exhausted from a 120 foot exhaust stack. Emissions from a 19-cell cooling tower will be released at a height of 57 feet. Table II contains the emission rates used in each of the modeling scenarios: turbine commissioning, turbine startup maximum 1-hour, maximum 8-hour, maximum 24-hour, and maximum annual average. Commissioning is the original startup of the turbines and only occurs during the initial operation of the equipment after installation. The startup of one turbine, with the other two turbines at maximum load, was used as the basis for the emissions for startup conditions.

The EPA models SCREEN3 and ISCST3 were used in the air quality impacts analysis. A land use analysis showed that the rural dispersion coefficients were required for the analysis. The models were run using three years of meteorological data (1997 through 1999) collected approximately 8 km south-southeast of the project at the San Joaquin Valley Unified Air Pollution Control District's Tracy Monitoring Station. The Ozone Limiting Method was employed to convert one-hour $NO_x$ impacts into one-hour $NO_2$ impacts. Hourly ozone monitoring data was also available from the Tracy Monitoring site for the same period (1997-1999). Because the exhaust stacks are less than Good Engineering Practice (GEP) stack height, ambient impacts due to building downwash were evaluated. The Ambient Ratio Methodology

(with a default $NO_2/NO_x$ ratio of 0.75) was used for determining the annual-averaged $NO_2$ concentrations. Because complex terrain was located nearby, complex terrain impacts were considered. Inversion breakup fumigation was evaluated using the SCREEN3 model.

Table II

Averaging period emission rates used in modeling analysis (g/s)

| Pollutant Source | Max. (1-hour) | Commissioning[1] (1-hour) | Start-up[2] (1-hour) | Max. (8-hour) | Max. (24-hour) | Max. Annual Average |
|---|---|---|---|---|---|---|
| $NO_x$ | | | | | | |
| Turbine/Duct Burner 1 | 3.00 | 43.3 | 30.2 | — | — | 2.50 |
| Turbine/Duct Burner 2 | 3.00 | — | 2.89 | | | 2.50 |
| Turbine/Duct Burner 3 | 3.00 | — | 2.89 | | | 2.50 |
| Auxiliary Boiler | 0.185 | — | — | | | 0.0635 |
| Emergency Generator | 0.814 | — | — | | | 0.0186 |
| Fire Pump | — | — | — | | | 0.00627 |
| Each Cooling Tower Cell (19 total) | — | — | — | | | — |
| CO | | | | | | |
| Turbine/Duct Burner 1 | 4.38 | 113.6 | 113.6 | 42.3 | — | — |
| Turbine/Duct Burner 2 | 4.38 | — | 4.22 | 42.3 | | |
| Turbine/Duct Burner 3 | 4.38 | — | 4.22 | 42.3 | | |
| Auxiliary Boiler | 0.627 | — | — | 0.627 | | |
| Emergency Generator | 0.854 | — | — | 0.107 | | |
| Fire Pump | — | — | — | — | | |
| Each Cooling Tower Cell (19 total) | — | — | — | — | | |
| $PM_{10}$ | | | | | | |
| Turbine/Duct Burner 1 | — | — | — | — | 1.13 | 1.32 |
| Turbine/Duct Burner 2 | | | | | 1.13 | 1.32 |
| Turbine/Duct Burner 3 | | | | | 1.13 | 1.32 |
| Auxiliary Boiler | | | | | 0.167 | 0.115 |
| Emergency Generator | | | | | 0.00272 | 0.00149 |
| Fire Pump | | | | | — | 0.000266 |
| Each Cooling Tower Cell (19 total) | | | | | 0.0159 | 0.0159 |

[1]Commissioning is the original startup of the turbines and only occurs during the initial operation of the equipment after installation. Only one turbine will be commissioned at a time. [2]Start-up is the beginning of any of the subsequent duty cycles to bring one turbine from idle status up to power production, while the other turbines are at maximum load.

### *Air Quality Modeling Results*

The maximum predicted ambient impacts of the various modeling procedures described above are summarized in Table III for the averaging periods for which AAQS and PSD increments have been set. Shown in Figure 1 are the locations of the maximum modeled impacts.

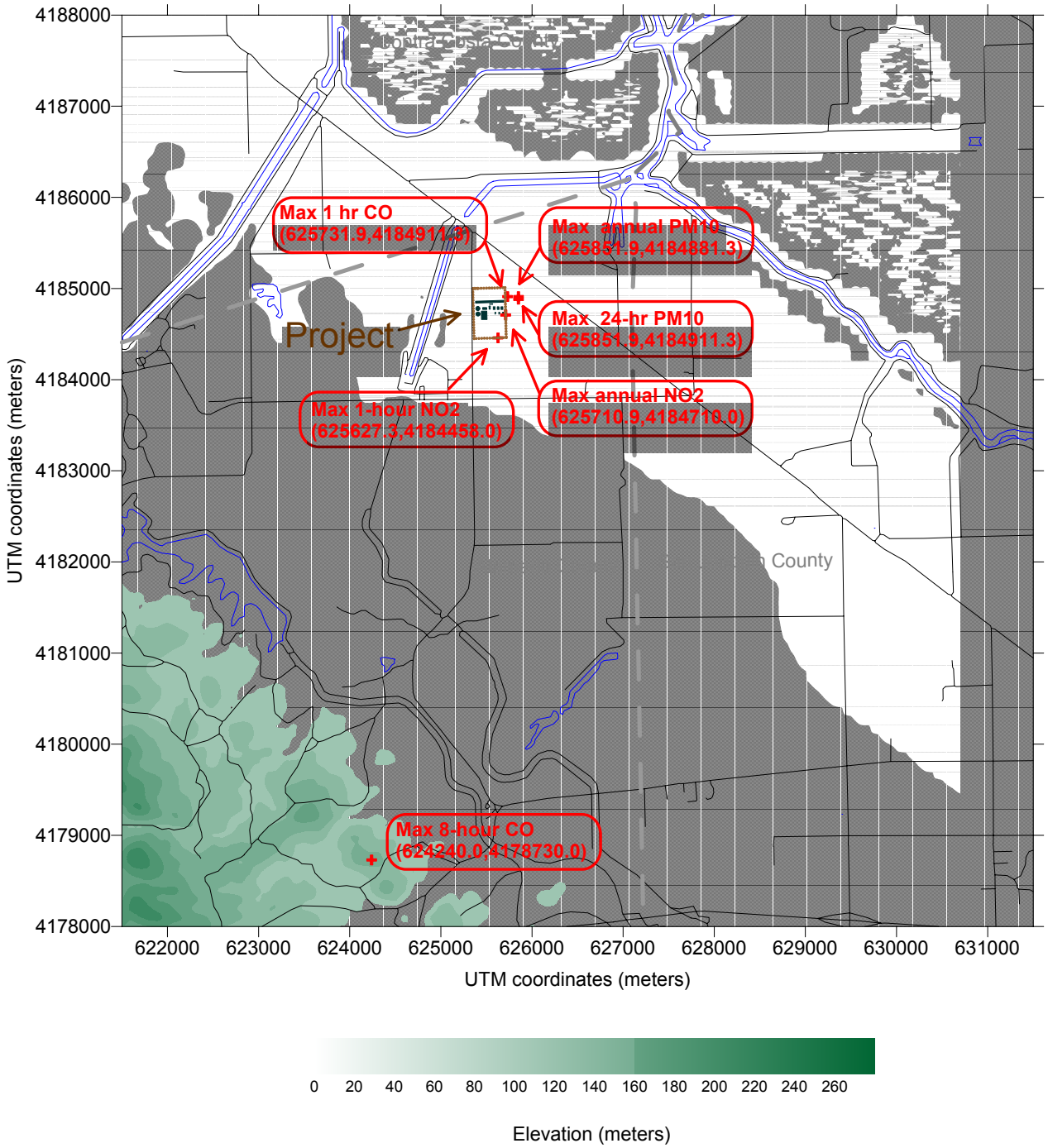


Figure 1. Location of project maximum impacts.

Also shown in Table III are the corresponding significant ambient impact levels listed in Section 233 of the District's NSR Rule. In accordance with Regulation 2-2-414 further analysis is required only for the those pollutants for which the modeled impact is above the significant air quality impact level. Table III shows that the only impact requiring further analysis is the 1-hour $NO_2$ modeled impacts.

TABLE III
Maximum predicted ambient impacts of proposed project (μg/m$^3$)
[maximums are in bold type]

| Pollutant | Averaging Time | Commissioning Maximum Impact | Start-up (1-hour) | Inversion Break-up Fumigation Impact | ISCST3 Modeled Impact | Significant Air Quality Impact Level |
|---|---|---|---|---|---|---|
| $NO_2$ | 1-hour | 127 | 104 | 64 | **236** | 19 |
| | annual | — | — | — | **0.56** | 1.0 |
| CO | 1-hour | 606 | **606** | 73 | 582 | 2000 |
| | 8-hour | — | — | — | **169** | 500 |
| $PM_{10}$ | 24-hour | — | — | 2.0 | **4.97** | 5 |
| | annual | — | — | — | **0.46** | 1 |

Background Air Quality Levels

Regulation 2-2-111 entitled "Exemption, PSD Monitoring," exempts an applicant from the requirement of monitoring background concentrations in the impact area (section 414.3) provided the impacts from the proposed project are less than specified levels. Table IV lists the applicable exemption standard and the maximum impact from the proposed facility. As shown, the modeled $NO_2$ impact is well below the preconstruction monitoring threshold.

TABLE IV
PSD monitoring exemption levels and maximum impacts
from the proposed project for $NO_2$ (μg/m$^3$)

| Pollutant | Averaging Time | Exemption Level | Maximum Impacts from Proposed Project |
|---|---|---|---|
| $NO_2$ | annual | 14 | 0.56 |

The San Joaquin Valley Air Pollution Control District-operated Tracy Monitoring Station, located 8.2 km south-southeast of the project, was chosen as being conservatively representative of the regional background $NO_2$ concentrations. Table V contains the concentrations measured at the station over the past 5 years (1996 through 2000).

TABLE V
Background $NO_2$ ($\mu g/m^3$) at the Tracy Patterson Pass Monitoring Station for the past five years (maximum is in bold type)

| | $NO_2$ |
|---|---|
| Year | Highest 1-hour average |
| 1996 | 115 |
| 1997 | 113 |
| 1998 | **149** |
| 1999 | 139 |
| 2000 | 128 |

Table VI below contains the comparison of the ambient standards with the proposed project impacts added to the maximum background concentrations. The California ambient $NO_2$ standard is not exceeded from the proposed project.

TABLE VI
California and national ambient air quality standards and ambient air quality levels from the proposed EAEC ($\mu g/m^3$)

| Pollutant | Averaging Time | Maximum Background | Maximum project impact | Maximum project impact plus maximum background | California Standard | National Standard |
|---|---|---|---|---|---|---|
| $NO_2$ | 1-hour | 149 | 236 | 385 | 470 | --- |

**CLASS I PSD INCREMENT ANALYSIS**

EPA requires an increment analysis of any PSD source which increases $NO_2$ or $PM_{10}$ concentrations by 1 $\mu g/m^3$ or more (24-hour average) inside a Class I area. Point Reyes National Seashore is located roughly 102 km to the west of the project and Pinnacles National Monument is located roughly 144 km south southeast of the project. Table VII shows the results of an impact analysis using ISCST3 for the maximum 24-hour $NO_2$ and $PM_{10}$ impacts within the Class I areas. All impacts were below the 1 $\mu g/m^3$ increments trigger level.

TABLE VII
Maximum predicted ambient impacts of proposed project ($\mu g/m^3$)

| Pollutant | Averaging Time | Point Reyes National Seashore | Pinnacles National Monument |
|---|---|---|---|
| $NO_2$ | 24-hour | .38 | .21 |
| $PM_{10}$ | 24-hour | .18 | .10 |

## VISIBILITY, SOILS AND VEGETATION IMPACT ANALYSIS

Visibility impacts were assessed using both EPA's VISCREEN visibility screening model and ISCST3. Both analyses show that the proposed project will not cause any impairment of visibility at the Point Reyes National Seashore or at the Pinnacles National Monument.

The project maximum one-hour average $NO_2$, including background, is 385 $\mu g/m^3$. This concentration is below the California one-hour average $NO_2$ standard of 470 $\mu g/m^3$. Crop damage from $NO_2$ requires exposure to concentrations higher than 470 $\mu g/m^3$ for periods longer than one hour.

Maximum project $NO_2$, CO, $SO_2$ and $PM_{10}$ concentrations would be less than all of the applicable national primary and secondary ambient air quality standards, which are designed to protect the public welfare form any known or anticipated effects, including plant damage. Therefore, the facility's impact on soils and vegetation would be insignificant.

## CONCLUSIONS

The results of the air quality impact analysis indicate that the proposed project would not interfere with the attainment or maintenance of applicable AAQS for $NO_2$, CO and $PM_{10}$. The analysis was based on EPA approved models and calculation procedures and was performed in accordance with Section 414 of the District's NSR Rule.

# Appendix F

BACT Cost-Effectiveness Analysis Data

# Appendix G

Compliance Certification