MARSH LANDING GENERATING STATION PROJECT

ATC/PTO APPLICATION

CONTRA COSTA COUNTY, CALIFORNIA

Prepared For:

- Bay Area Air Quality Management District

Prepared on behalf of

Mirant Marsh Landing, LLC

June 25, 2008

URS

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List of Acronyms

$\mu g/m^3$	micrograms per cubic meter
°C	degrees Celsius
°F	degrees Fahrenheit
AAQS	Ambient Air Quality Standards
ACHE	Air-cooled heat exchanger
AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
AFC	Application for Certification
APN	Assessor's Parcel Number
AQRV	Air quality related values
ATC	Authority to construct
BAAQMD	Bay Area Air Quality Management District
BACT	Best available control technology
BPIP-Prime	Building Parameter Input Program – Prime
CAAQS	California Ambient Air Quality Standards
CARB	California Air Resources Board
CCPP	Contra Costa Power Plant
CEC	California Energy Commission
CO	carbon monoxide
CTG	Combustion turbine generator
DAS	Data acquisition system
DEM	digital elevation models
DOC	Determination of compliance
FLAG	Federal Land Managers' Air Quality Related Values Workgroup
FP10	Flex Plant 10
HARP	Hotspots analysis and reporting program
HHV	higher heating value
HI	hazard index
HRA	Health risk assessment
HRSA	Health Risk Screening Analysis
HRSG	Heat recovery steam generator
ISCST3	Industrial Source Complex Short Term 3rd version
IWAQM	Interagency Workgroup on Air Quality Modeling
kg/ha-yr	kilogram per hectare per year
km	kilometers
LORS	Laws, ordinances, regulations, and standards
MLGS	Marsh Landing Generating Station
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NO_x	Nitrogen oxides
NPS	National Park Service
NSR	New source review
NWS	National Weather Service
O_3	ozone

OEHHA	Office of Environmental Health Hazard Assessment
OLM	ozone limiting method
Pb	lead
PG&E	Pacific Gas & Electric
PM_{10}	particulate matter less than 10 μm in diameter
$PM_{2.5}$	particulate matter less than 2.5 μm in diameter
ppb	parts per billion
ppm	parts per million
PSD	Prevention of significant deterioration
RH	relative humidity
ROC	Reactive organic compound
SCR	Selective catalytic reduction
SIL	Significant impact level
SO_x	sulfur oxide
STG	steam turbine generator
TAC	toxic air contaminants
tpy	tons per year
ULN	Ultra Low NOx
USEPA	United States Environmental Protection Agency
USFS	United States Forest Service
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	volatile organic compounds

1.0 INTRODUCTION

Mirant Marsh Landing, LLC proposes to build and operate a new 930 MW natural-gas–fired generation facility with four power blocks: two Siemens FP10 combined-cycle units and two Siemens 5000F simple-cycle units. The proposed Marsh Landing Generating Station (MLGS) units are to be constructed wholly within the existing Contra Costa Power Plant (CCPP) site. This document is an Authority to Construct / Permit to Operate Application to the Bay Area Air Quality Management District (BAAQMD) for the MLGS project.

The existing CCPP is an already permitted major facility. The proposed MLGS is also classified as a major facility and will apply for a new Title V permit.

1.1 *Overview*

Mirant Marsh Landing, LLC proposes to build and operate new natural-gas–fired generation facilities and ancillary systems. The proposed MLGS units are to be constructed wholly within the existing CCPP site. The MLGS will redevelop approximately 27 acres of the CCPP site that are currently occupied by five fuel storage tanks, temporary buildings and other ancillary facilities. The MLGS will be located within the existing CCPP site, Assessor's Parcel Number (APN) 051-031-014, in unincorporated Contra Costa County, California. The location of this facility and the aerial overview of the proposed Marsh landing Generating Station are shown on Figure 1-1 and Figure 1-2.

Construction of the new power generation facility is expected to occur over a 33-month period (from October 2009 through June 2012). Construction is expected to cost approximately $800 million (in 2008 dollars).

The generator output from the MLGS will be stepped-up to 230-kV transmission voltage and consists of four power blocks: two Siemens Flex Plant 10 (FP10) units operating in combined cycle; and two Siemens 5000F combustion turbine units operating in simple-cycle mode. The FP10 units will be intermediate-load power blocks, expected to operate at 40 to 50 percent capacity factor, and generating approximately 550 megawatts (MW) (net) when both are operated together at a temperature of 75 degrees Fahrenheit (°F) and 54 percent relative humidity. The simple-cycle power blocks will provide peaking power and are expected to operate at less than 10 percent capacity factor, generating approximately 380 MW (net) when operated together at 75°F and 54 percent relative humidity. Commercial operation for the FP10 units is expected by summer 2012. Commercial operation for the simple-cycle units could be as early as summer 2011. The MLGS will use air-cooled heat exchanger technology to limit consumptive water use.

Each Siemens FP10 unit includes one combustion turbine generator (CTG) equipped with dry ultra low NO_X (ULN) combustors and inlet air evaporative cooler, one heat recovery steam generator (HRSG), one steam turbine generator (STG), an air-cooled heat exchanger (ACHE), and associated auxiliary systems and equipment. Each HRSG will be equipped with an emissions control system to include a SCR and carbon monoxide (CO) catalyst, an ammonia system, a continuous emissions monitoring system (CEMS), and stack.

Each Siemens 5000F simple-cycle unit will consist of one Siemens 5000F natural-gas–fired CTG. The nominal net generating capacity of each simple-cycle turbines will be approximately 190 net MW. Each Siemens 5000F natural-gas–fired CTG will be equipped with an emissions control system to include a SCR and oxidation catalyst, an ammonia system, tempering air skids, a CEMS, and stack.

The fuel for all CTGs and preheaters will be pipeline-quality natural gas. Natural gas will be delivered to the MLGS by PG&E via a new 12-inch-diameter gas line connection from interstate transmission Line 400, which runs along the eastern boundary of the Gateway Generating Station (GGS) site. The new gas line will continue generally westward to the new MLGS gas metering and gas compression station and new fuel gas preheaters on the MLGS site.

Several of the components of the proposed project will be located outside of the proposed MLGS boundary but within the CCPP, or directly adjacent. Construction laydown and parking areas will all be located within the CCPP site at 3201 Wilbur Avenue on previously disturbed, graded, or paved areas of the power plant site. The gas interconnection line will run east from the MLGS compressor building through the CCPP site to an existing gas transmission line (Line 400) adjacent to the GGS site. The underground gas line will occupy an existing easement across the GGS site. Electric transmission lines will connect directly to the PG&E switchyard adjacent to the MLGS site (see Figure 1-1).

As a part of ongoing maintenance, Mirant Delta, LLC plans to drain, clean and demolish all of the existing tanks at the CCPP (i.e. Tanks 1-8) in 2008. Should this not occur, the demolition of Tanks 1-5 will occur as a part of the MLGS project construction.

In addition, PG&E, on the parcel to the east of the CCPP, is currently constructing the GGS, a new generation facility approved by the CEC in May 2001 (Docket Number 00-AFC-1) and amended in 2007. Construction is expected to be completed in early 2009, prior to construction of the MLGS. Activities associated with the construction and operations of the GGS are not a part of this project.

Emission increases from the MLGS will be offset according to BAAQMD Regulation 2. Details of the emissions increases as a result of the project and offsets are discussed in Section 4.0 and Section 6.0, respectively.

Dispersion modeling was conducted to determine the potential impacts of criteria pollutant and hazardous air pollutant (HAP) emissions. The impacts from the project will not exceed any of the California state or Federal Ambient Air Quality Standards (AAQS). However, the project will trigger Prevention of Significant Deterioration (PSD) Review. Section 7.0 details the AAQS standards and the PSD analysis. The project will not cause any exceedance of PSD significant ground level concentrations. The modeled health risk of toxic air emission increases are below significance levels as discussed in Section 9.0

The proposed MLGS project will trigger Best Available Control technology (BACT) requirements for Nitrogen Oxides (NO_x), Sulfur Oxides (SO_x), Volatile Organic Compound (VOC), Particulate Matter (PM), and Carbon Monoxide (CO). Section 8.0 describes the BACT analysis and proposed technologies that will be included to meet BACT requirements as implemented by the BAAQMD.

1.2 *Applicant Background Information*

1.2.1 Business Name/Location

Mirant Marsh Landing, LLC - Marsh Landing Generating Station

The MLGS will be located within the existing CCPP site, Assessor's Parcel Number (APN) 051-031-014, in unincorporated Contra Costa County, California.

1.2.2 Nature of Business

The proposed Marsh Landing Generating Station facility is an electric power generation facility.

1.2.3 Person to Contact Regarding Application

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Ronald.kino@mirant.com

1.2.4 Type of Entitlement

This document is an application for an Authority to Construct /Permit to Operate for the MLGS project to be issued by the BAAQMD. The project includes two Siemens FP10 units operating in combined cycle; two Siemens 5000F combustion turbine units operating in simple-cycle mode; and two fuel gas preheaters to treat the natural gas fuel stream to the turbines. Each HRSG (FP10 units only) will be equipped with an emissions control system to include an SCR and carbon monoxide (CO) catalyst, an ammonia system, a continuous emissions monitoring system (CEMS), and stack. Each Siemens 5000F natural-gas–fired CTGs will be equipped with an emissions control system to include a SCR and oxidation catalyst, an ammonia system, tempering air skids, a CEMS, and stack. One fuel gas preheater will serve the combined cycle power blocks (two FP-10 units). The other fuel gas preheater will serve the simple cycle power blocks (two Siemens 5000F natural-gas–fired CTGs).

1.2.5 Estimated Construction and Completion Dates

Construction of the new power generation facility is expected to occur over a 33-month period (from October 2009 through June 2012). Commercial operation for the FP10 units is expected by summer 2012. Commercial operation for the simple-cycle units could be as early as summer 2011.

1.2.6 Application Status

This document is an original Authority to Construct /Permit to Operate application.

1.2.7 Operating Schedule

The FP10 units will be intermediate-load power blocks, expected to operate at 40 to 50 percent capacity factor.

The simple-cycle power blocks will provide peaking power and are expected to operate at less than 10 percent capacity factor.

The natural gas-fired fuel preheaters were conservatively assumed to operate at maximum capacity for the turbine operations.

1.2.8 Compliance Certification

Mirant certifies that all facilities owned or operated by the Mirant Delta, LLC within the state are in compliance with applicable federal, state, and BAAQMD emission limits and applicable environmental standards.

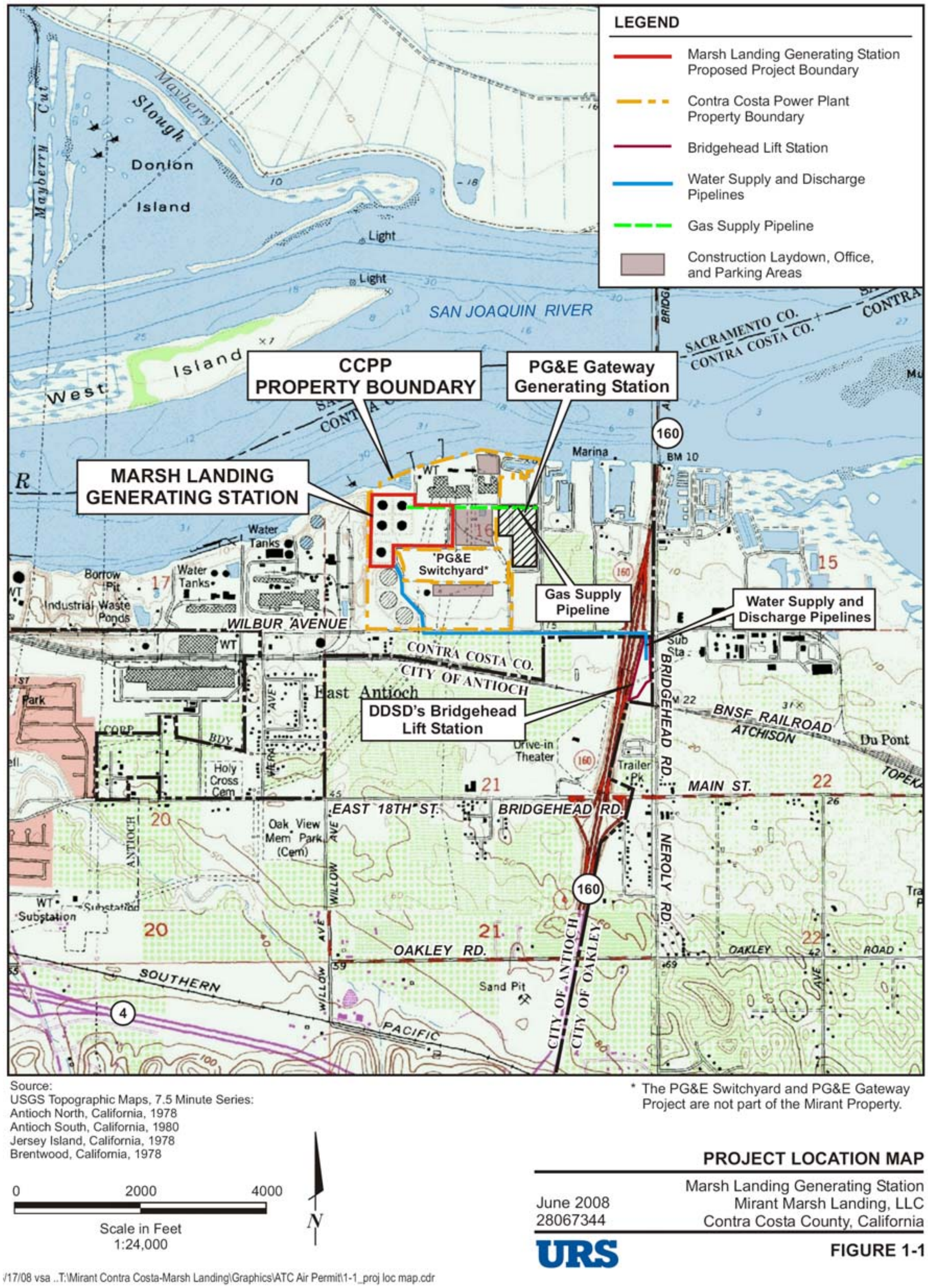
LEGEND
Marsh Landing Generating Station Proposed Project Boundary
Contra Costa Power Plant Property Boundary
Bridgehead Lift Station
Water Supply and Discharge Pipelines
Gas Supply Pipeline
Construction Laydown, Office, and Parking Areas
SAN JOAQUIN RIVER
Donlon Island
Mayberry Slough
Mayberry Cut
West Island
Light
SACRAMENTO CO.
CONTRA COSTA CO.
CCPP PROPERTY BOUNDARY
PG&E Gateway Generating Station
MARSH LANDING GENERATING STATION
PG&E Switchyard
Gas Supply Pipeline
Water Supply and Discharge Pipelines
DDSD's Bridgehead Lift Station
Water Tanks
Borrow Pit
Industrial Waste Ponds
WILBUR AVENUE
CONTRA COSTA CO.
CITY OF ANTIOCH
East Antioch
BNSF RAILROAD
ATCHISON
Du Pont
TOPEKA
Marina
BM 10
160
BRIDGEHEAD RD.
MAIN ST.
EAST 18TH ST.
BRIDGEHEAD RD.
NEROLY RD.
Holy Cross Cem
Oak View Mem Park (Cem)
WILLOW AVE
Drive-in Theater
Trailer Pk
OAKLEY RD.
OAKLEY ROAD
SOUTHERN PACIFIC
Sand Pit
CITY OF ANTIOCH
CITY OF OAKLEY
Substation
4
Source:
USGS Topographic Maps, 7.5 Minute Series:
Antioch North, California, 1978
Antioch South, California, 1980
Jersey Island, California, 1978
Brentwood, California, 1978
* The PG&E Switchyard and PG&E Gateway Project are not part of the Mirant Property.
0 2000 4000
Scale in Feet
1:24,000
N
PROJECT LOCATION MAP
Marsh Landing Generating Station
Mirant Marsh Landing, LLC
Contra Costa County, California
June 2008
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FIGURE 1-1
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AERIAL VIEW OF PROPOSED POWER PLANT

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Marsh Landing Generating Station
Mirant Marsh Landing, LLC
Contra Costa County, California

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FIGURE 1-2

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Note: This figure includes the simulation of PG&E's Gateway Generating Station which is currently under construction

2.0 PROJECT DESCRIPTION

2.1 *Equipment*

The project includes two Siemens Flex Plant 10 (FP10) units operating in combined cycle; two Siemens 5000F combustion turbine units operating in simple-cycle mode; and two natural gas-fired fuel preheaters (one for the combined cycle units and one for the simple cycle units).

Each Siemens FP10 unit includes one combustion turbine generator (CTG) equipped with ultra low NO_X (ULN) combustors and inlet air evaporative cooler, one heat recovery steam generator (HRSG), one steam turbine generator (STG), an air-cooled heat exchanger (ACHE), and associated auxiliary systems and equipment (see Figure 2-1). Each HRSG (FP10 units only) will be equipped with an emissions control system to include a SCR for NO_x control and carbon monoxide (CO) catalyst, an ammonia system, a continuous emissions monitoring system (CEMS), and stack.

The Siemens 5000F simple-cycle units will consist of two Siemens 5000F natural-gas–fired CTGs equipped with ultra low NO_X (ULN) combustors. Each Siemens 5000F natural-gas–fired CTGs will be equipped with an emissions control system to include a SCR and oxidation catalyst, an ammonia system, tempering air skids, a CEMS, and stack.

Exhaust gases from each power block will be discharged from a stack that is expected to be approximately 151 ft tall. Steam from each HRSG (FP10 units only) will be used to drive a steam turbine generator. The process flow diagram for the simple-cycle generation and FP10 units are shown on Figure 2-2 and Figure 2-3, respectively. The heat and material balances for the facility are also shown on the same figures as well as in Table 2-1and Table 2-2. Three cases are shown on the figure for the all power block units: summer design conditions (94°F), average conditions (59°F), and extreme winter conditions (20°F). For the summer and average conditions, evaporative cooling is included for both power blocks. In addition, when operating at 100 percent load, power augmentation may be used in the FP10 units. For the winter case, neither evaporative coolers nor power augmentation are in operation. The winter case is the lowest temperature at which the units would ever be expected to operate.

The two natural gas-fired fuel preheaters will be installed to condition the natural gas fuel to the turbines. These units each will be rated at a fuel energy input of 5 MMBtu/hour. One fuel gas preheater will serve the combined cycle power blocks (two FP-10 units). The other fuel gas preheater will serve the simple cycle power blocks (two Siemens 5000F natural-gas–fired CTGs).

Although in reality the heaters will not be used during some turbine operating periods, it has been conservatively assumed for this analysis that each will operate at maximum capacity for the turbine operations. Based on BAAQMD Regulation 2-1-114, the two natural gas-fired fuel preheaters are exempt from permitting because they are less than 10 MMBtu/hour and fired on natural gas. However, these units will still be discussed in this application as a part of the project.

2.2 *Fuel*

The MLGS will use natural gas that will be delivered via a new 12-inch-diameter gas line connection from interstate transmission Line 400, which runs along the eastern boundary of the GGS site. The new gas line will continue generally westward to the new MLGS gas metering and gas compression station on the MLGS site. The fuel gas has an average high heating value (HHV) between 990 and 1,050 British thermal units (Btu)/scf and will normally range from 1,000 to 1,030 Btu/scf.

The natural gas pressure will be increased by gas compressors to a pressure of approximately 600 pounds per square inch gauge (psig), filtered, and pressure-regulated before entering the CTG.

Safety pressure relief valves will be provided to protect the natural gas system components from overpressurization.

Estimated emissions of sulfur oxides for combustion of this fuel by the project's equipment assumed full oxidation of all fuel sulfur to SO_2 and a natural gas sulfur content of 0.40 grains per 100 standard cubic feet (scf) annual average. For short-term emissions a conservative estimate of a natural gas sulfur content of 1.0 grains per 100 scf was used for the calculations, as 1.0 grain per 100 scf is the upper limit as specified in PG&E's Rule 21 of Section C.

2.3 *Electrical*

The four power blocks (two Siemens FP10 combined-cycle units and two Siemens 5000F simple-cycle units) of the proposed MLGS project will produce an additional 930 MW. Each of the four combustion-gas turbines and two steam turbines will be connected to separate electric generators. The generators for the MLGS will be interconnected to the PG&E switchyard located adjacent to the CCPP site. The MLGS will be interconnected to the transmission grid, and power generated by the facility will be available to serve energy needs throughout California.

2.4 *Process Operation*

The MLGS project includes two Siemens Flex Plant 10 (FP10) units operating in combined cycle; and two Siemens 5000F combustion turbine units operating in simple-cycle mode.

The average net generating capacity of each of the FP10 units will be approximately 275 MW. The actual net output of the system will vary in response to ambient air temperature conditions, use of evaporative coolers, amount of auxiliary load, generator power factor, firing conditions of the combustion turbines, and other operating factors.

The nominal net generating capacity of each simple-cycle turbines will be approximately 190 net MW. The actual output of the system will vary in response to ambient air temperature conditions and the use of evaporative coolers. Full load output of a simple-cycle unit under expected operating conditions will range from approximately 180 net MW to a peak of 220 net MW. The units can also operate at partial load with one or both CTGs running at minimum load.

The process flow diagram for the simple-cycle generation and FP10 units are shown on Figure 2-2 and Figure 2-3, respectively.

2.5 *Emission Control Technology*

This section describes the technologies included in the Marsh Landing Generating Station project to minimize the emission of criteria pollutants, specifically NO_x and CO.

2.5.1 NO_x Emissions Control

In the proposed Simple Cycle and Combined Cycle power blocks, NO_x will be controlled in two methods:

1. By the use of Ultra Low NO_x (ULN) combustors to limit the initial NO_x formation.
2. By the use of Selective Catalytic Reduction (SCR) emissions control equipment to remove NO_x from the combustion gas exhaust.

ULN combustors in the CTGs, followed by SCR in the FP10 HRSGs and at the simple-cycle CTG flue gas outlets, will control stack emissions of NO_X to a maximum 2.5 parts per million by volume, dry (ppmvd) (corrected to 15 percent O_2, 1-hour average excluding startups) for the simple-cycle units, and 2.0 ppmvd for the FP10s. The ULN combustors control NO_X emissions to approximately 9.0 ppmvd at the CTG exhausts by pre-mixing fuel and air immediately before combustion. Pre-mixing inhibits NO_X formation by minimizing the flame temperature and the concentration of oxygen at the flame front.

The SCR process will use aqueous ammonia (NH_3) as a reagent. Stack emissions of ammonia, referred to as "ammonia slip," will not exceed 5 ppmvd for FP10 units and 10 ppm for simple-cycle units. The SCR system includes a catalyst chamber located within each FP10 HRSG, and at the simple-cycle CTG flue gas outlet, catalyst bed, ammonia storage system, ammonia vaporization system, and ammonia injection system. The catalyst chamber contains the catalyst bed and is located in a temperature zone of the FP10 HRSG where the catalyst is most effective over the range of loads at which the plant will operate. Dilution air fans will be used for the simple-cycle CTG SCR system to reduce the flue gas temperature to the effective catalyst operating temperature. The ammonia injection grid is located upstream of the catalyst chamber. It is expected that the 20,000-gallon aqueous ammonia storage tank will have a 10-day storage capacity.

2.5.2 CO and VOC Emissions Control

An oxidation catalyst will be provided in the FP10 HRSG and at the simple-cycle CTG flue gas outlets to limit CO emissions to less than 3 ppmvd, and VOC emissions to less than 2 ppmvd (corrected to 15 percent O_2). These emission levels correspond to current California best available control technology (BACT). This catalytic system will promote the oxidation of CO to carbon dioxide, and VOC to carbon dioxide and water vapor, without the need for additional reagents. The catalyst has a design life of seven to ten years.

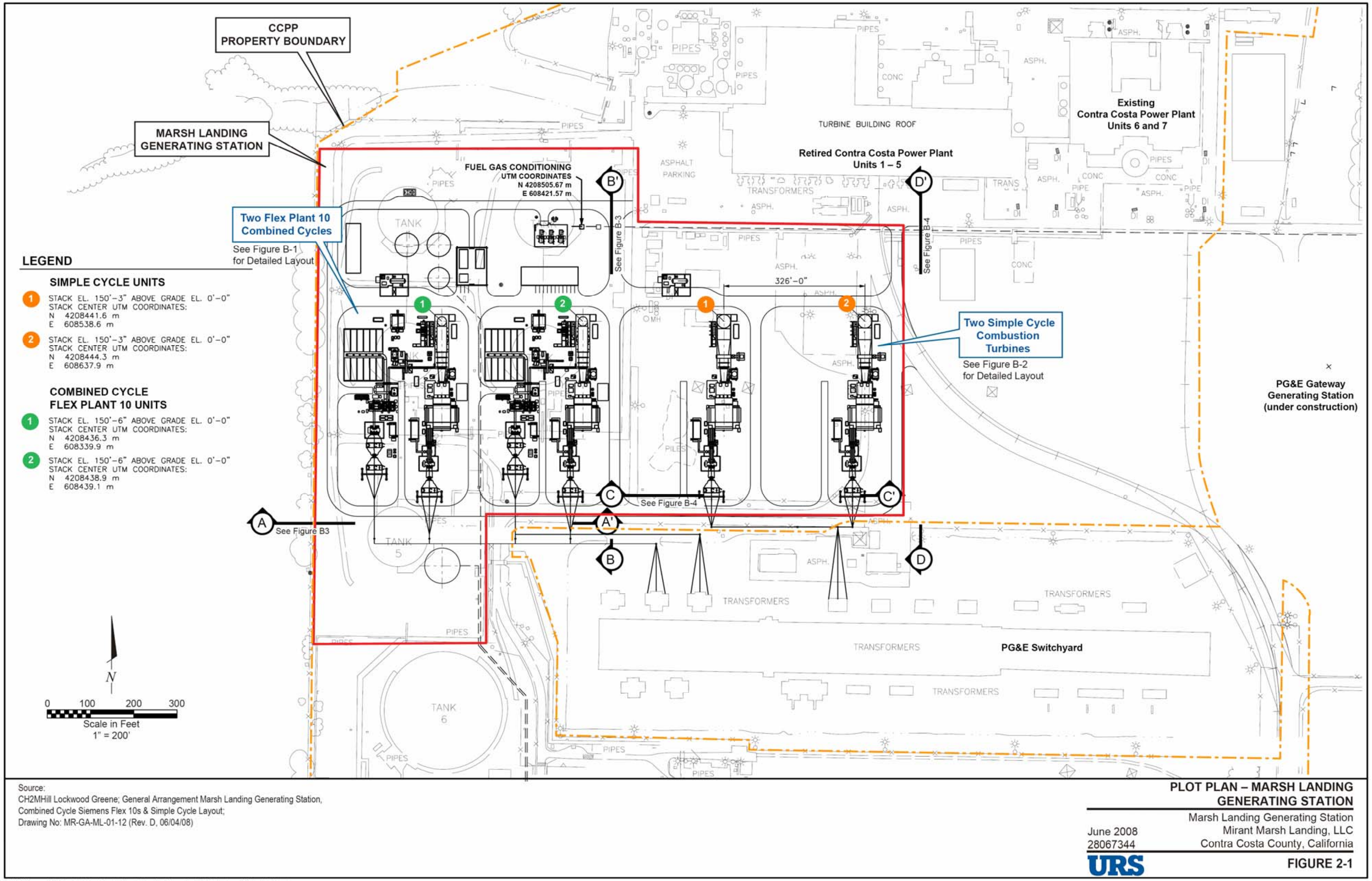
2.5.3 PM10 and SO2 Emissions Control

PM_{10} emissions consist primarily of hydrocarbon particles formed during combustion. PM_{10} emissions will be controlled by inlet air filtration and by the use of natural gas fuel, which contains essentially zero particulate matter.

SO_2 emissions will be controlled by the use of pipeline-quality natural gas, which contains only trace quantities of sulfur from the injected mercaptan odorant.

2.5.4 Continuous Emission Monitoring

The continuous emissions monitoring system (CEMS) uses dilution and/or direct extractive sampling techniques for in-stack or in-duct monitoring. For each CTG, a separate CEMS will sample, analyze, and record fuel gas flow rate, NO_x and CO concentration levels, and percentage of O_2 in the exhaust gas from the stacks. The CEMS systems will transmit data to a data acquisition system (DAS) that will store the data and generate emission reports in accordance with permit requirements. The DAS will also include alarm features that will send signals to the plant DCS when the emissions approach or exceed pre-selected limits.



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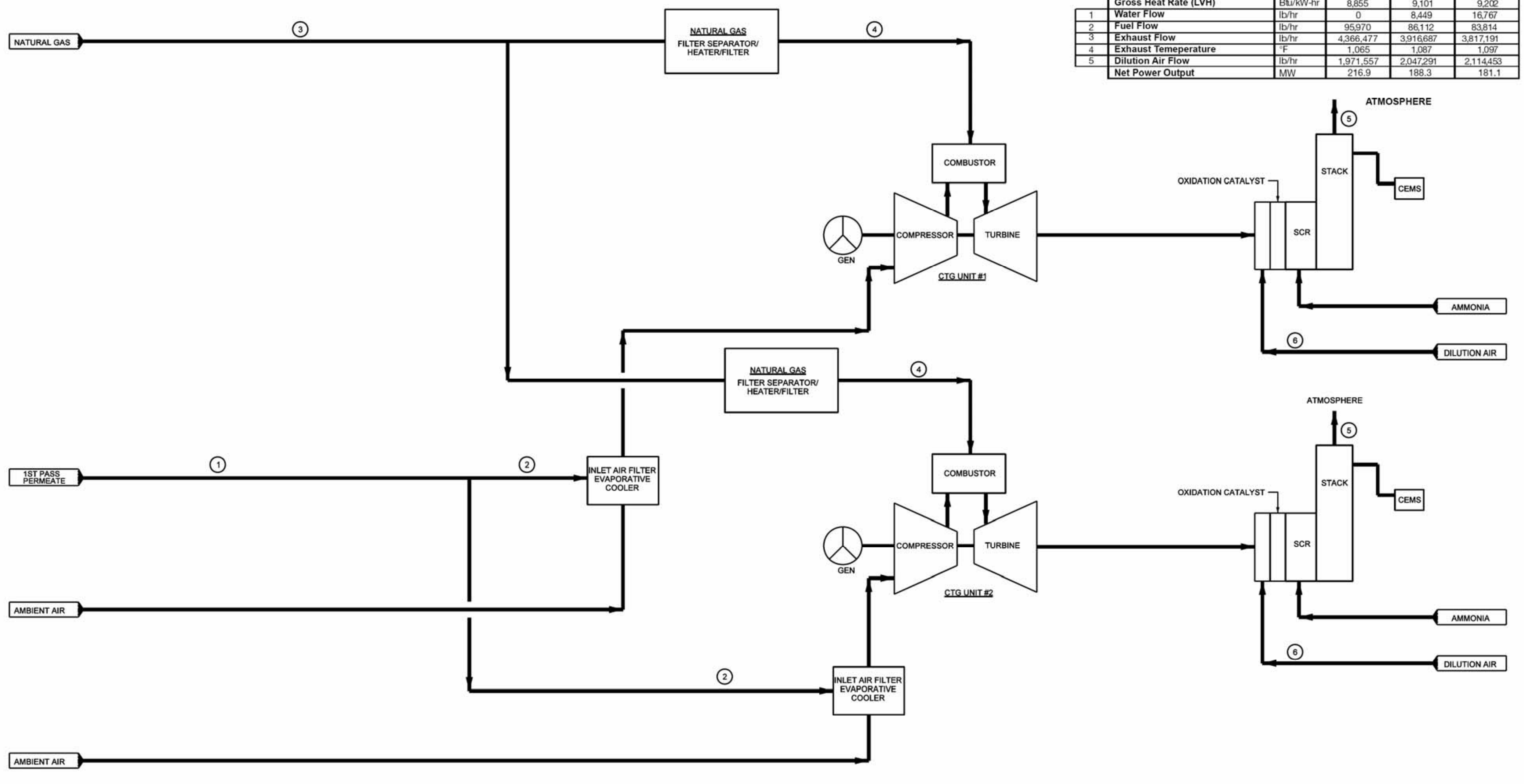
		Units	20°F, 90% RH 100% Load	75°F, 54% RH 100% Load	94°F, 32% RH 100% Load
	Gross Power Output	MW	224.1	194.7	187.5
	Gross Heat Rate (LVH)	Btu/kW-hr	8,855	9,101	9,202
1	Water Flow	lb/hr	0	8,449	16,767
2	Fuel Flow	lb/hr	95,970	86,112	83,814
3	Exhaust Flow	lb/hr	4,366,477	3,916,687	3,817,191
4	Exhaust Temeperature	°F	1,065	1,087	1,097
5	Dilution Air Flow	lb/hr	1,971,557	2,047,291	2,114,453
	Net Power Output	MW	216.9	188.3	181.1



Source:
CH2MHill Lockwood Greene; Process Flow Diagram, Marsh Landing Generation Station
Siemens 5000F Simple Cycle Heat & Material Balance
Drawing No: MC-PR-20-20-01 (Rev. P1, 04/04/08)

SIMPLE CYCLE HEAT AND MATERIAL BALANCE

Marsh Landing Generating Station
Mirant Marsh Landing, LLC
Contra Costa County, California

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FIGURE 2-2

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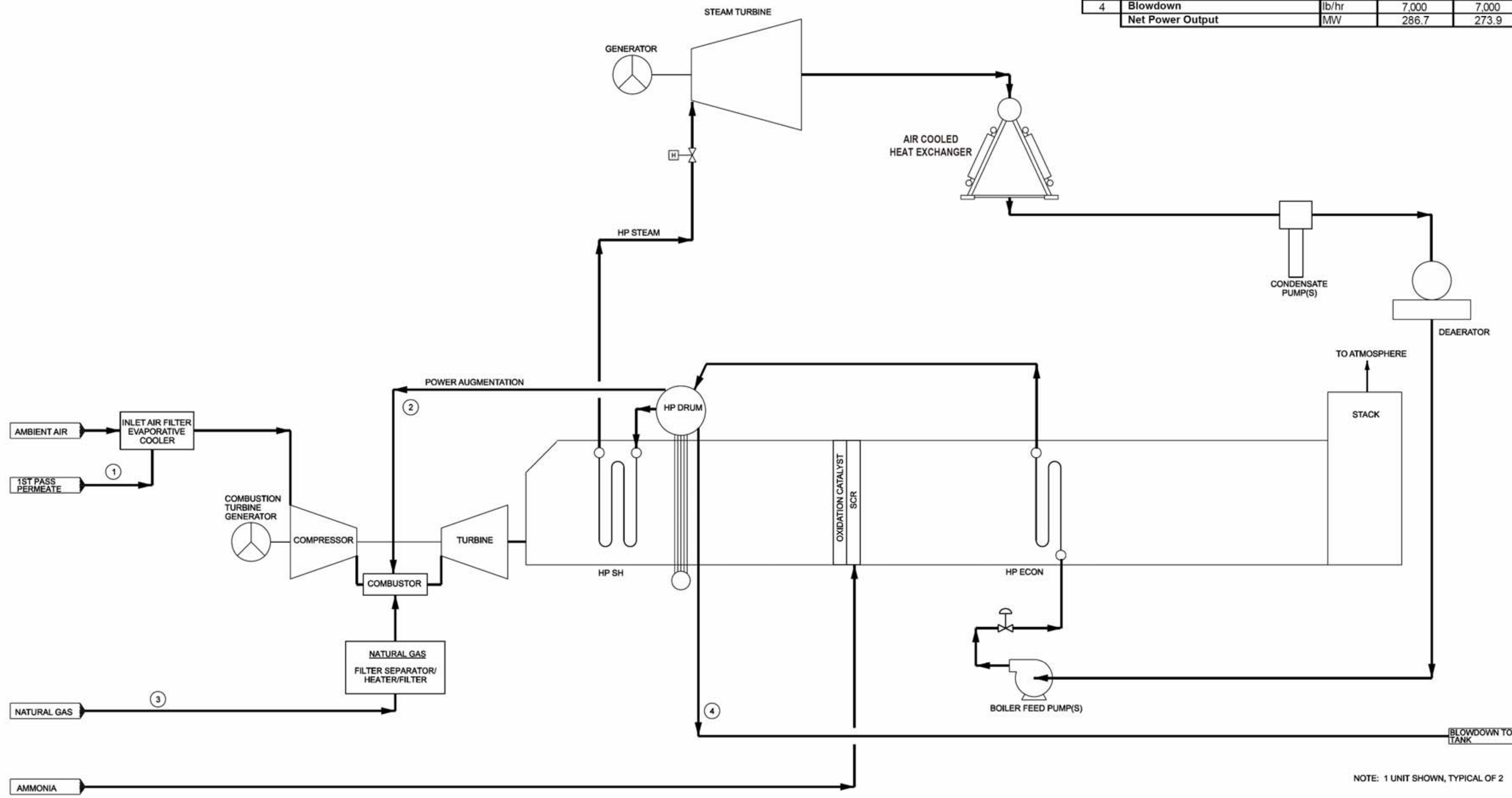
		Units	20°F, 90% RH 100% Load	75°F, 54% RH 100% Load	94°F, 32% RH 100% Load
	Gross Power Output	MW	295.3	282.1	274.5
	Gross Heat Rate (LVH)	Btu/kW-hr	6,927	6,981	6,976
1	**Water Flow (Evap Cooler)**	lb/hr	0	13,000	30,000
2	**Steam Flow (Power Augmentation)**	lb/hr	0	13,687	133,687
3	**Fuel Flow**	lb/hr	98,965	94,944	92,637
4	**Blowdown**	lb/hr	7,000	7,000	7,000
	Net Power Output	MW	286.7	273.9	266.5



Source:
CH2MHill Lockwood Greene; Process Flow Diagram, Marsh Landing Generation Station
Siemens Flex Plant 10 Comb. Cycle Heat & Material Balance
Drawing No: MC-PR-20-20-02 (Rev. P1, 04/04/08 & 5/12/08)

FLEX PLANT 10 HEAT AND MATERIAL BALANCE

Marsh Landing Generating Station
Mirant Marsh Landing, LLC
Contra Costa County, California

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FIGURE 2-3

6/17/08 vsa ..\T:\Mirant Contra Costa-Marsh Landing\Graphics\ATC Air Permit\2-35_HMB_flex plant 10.ai

Table 2-1 Heat and Material Balance Case Descriptions - Simple-Cycle Power Blocks

Case		Ambient Temperature (°F)	Relative Humidity (percent)	CTG Load (percent)	Evaporative Cooling	Power Augmentation
4	A	94	32	100	Yes	n/a
	B	94	32	75	Yes	n/a
	C	94	32	60	Yes	n/a
5	A	60	54	100	Yes	n/a
	B	60	54	75	Yes	n/a
	C	60	54	60	Yes	n/a
6	A	20	90	100	No	n/a
	B	20	90	75	No	n/a
	C	20	90	60	No	n/a

n/a = not applicable

Table 2-2 Heat and Material Balance Case Description – Flex Plant 10 Power Blocks

Case		Ambient Temperature (°F)	Relative Humidity (percent)	CTG Load (percent)	Evaporative Cooling	Power Augmentation
1	A	94	32	100	Yes	Yes
	B	94	32	85	Yes	No
	C	94	32	60	Yes	No
2	A	59	54	100	Yes	Yes
	B	59	54	85	Yes	No
	C	59	54	60	Yes	No
3	A	20	90	100	No	No
	B	20	90	85	No	No
	C	20	90	60	No	No

3.0 EQUIPMENT SPECIFICATIONS

3.1 *Equipment List*

This section summarizes specifications regarding the following equipment comprising the Marsh landing Generating Station Project.

S-1 CTG #1, Siemens FP10 Natural Gas-Fired CTG, 275 MW; 2271 million (MM)BTU per hour with Ultra Low NO_x combustors; abated by A-1 CO Catalyst System and A-2 SCR System

S-2 CTG #2 Siemens FP10 Natural Gas-Fired CTG, 275 MW; 2271 million (MM)BTU per hour with Ultra Low NO_x combustors; abated by A-3 CO Catalyst System and A-4 SCR System

S-3 CTG #3 Siemens SGT6-5000F Natural Gas-Fired CTG, 190 MW; 2202 million (MM)BTU per hour with Ultra Low NO_x combustors; abated by A-5 CO Catalyst System and A-6 SCR System

S-4 CTG #4 Siemens SGT6-5000F Natural Gas-Fired CTG, 190 MW; 2202 million (MM)BTU per hour with Ultra Low NO_x combustors; abated by A-7 CO Catalyst System and A-8 SCR System

S-5 Natural Gas Fired Fuel Preheater; 5.00 million (MM)BTU per hour; Serving S-1 and S-2

S-6 Natural Gas Fired Fuel Preheater; 5.00 million (MM)BTU per hour; Serving S-3 and S-4

A-1 CO Catalyst System #1 abating emissions from CTG #1 (S-1)

A-2 SCR System #1 abating emissions from CTG #1 (S-1)

A-3 CO Catalyst System #2 abating emissions from CTG #2 (S-2)

A-4 SCR System #2 abating emissions from CTG #2 (S-2)

A-5 CO Catalyst System #3 abating emissions from CTG #3 (S-3)

A-6 SCR System #3 abating emissions from CTG #3 (S-3)

A-7 CO Catalyst System #4 abating emissions from CTG #4 (S-4)

A-8 SCR System #4 abating emissions from CTG #4 (S-4)

P-1 Stack #1 releasing emissions from CTG #1 (S-1) after being abated by CO Catalyst System #1 (A-1) and SCR System #1 (A-2)

P-2 Stack #2 releasing emissions from CTG #2 (S-3) after being abated by CO Catalyst System #2 (A-3) and SCR System #2 (A-4)

P-3 Stack #3 releasing emissions from CTG #3 (S-5) after being abated by CO Catalyst System #3 (A-5) and SCR System #3 (A-6)

P-4 Stack #4 releasing emissions from CTG #4 (S-6) after being abated by CO Catalyst System #4 (A-7) and SCR System #4 (A-8)

P-5 Preheater Emission Point following natural gas-fired fuel preheater (S-5)

P-6 Preheater Emission Point following natural gas-fired fuel preheater (S-6)

3.2 *Gas Turbines*

Quantity:	Two Units
Mfg:	Siemens
Model:	SGT6-5000F
Performance:	
Base Rating	190 MW
Heat Rating	8,855 to 9,202 BTU/kilowatt hour (kWhr)
Turbine Stack Temperature	750 F

Quantity:	Two Units
Mfg:	Siemens
Model:	Flex Plant 10
Performance:	
Base Rating	275 MW
Heat Rating	~ 7,020 – 7,795 BTU/kilowatt hour (kWhr)
Turbine Stack Temperature	333 to 350 F

3.3 *Heat Recovery Steam Generators*

Quantity:	Two Units
Mfg:	Siemens
Model:	TBD
Type:	Submerged-tube heat exchanger with single-pressure design and extended fin-tube construction. Each HRSG will be equipped with an emissions control system to include a SCR and carbon monoxide (CO) catalyst, an ammonia system, a continuous emissions monitoring system (CEMS), and stack.
Performance:	1,700 psig steam each

3.4 *Selective Catalytic Reduction*

Quantity:	Four Units
Mfg:	Siemens
Type:	Vanadium pentoxide
Performance:	
Gas Flow	TBD
Gas Temperature	TBD
NO_x Reduction	2.5 ppmvd for Simple Cycles, 2.0 ppmvd for FP10s
Differential Pressure	TBD
Catalyst Life	7 to 10 years

3.5 *CO Catalyst*

Quantity:	Four Units
Mfg:	Siemens
Type:	CO Catalyst
Performance:	

Gas Flow	TBD
Gas Temperature	TBD
CO Reduction	Reduces CO concentration to < 3 ppmvd, @ 15 % O_2
NMHC Conversion	Reduces VOC concentration to < 2 ppmvd, @ 15 % O_2
Differential Pressure	TBD
Catalyst Life	7 to 10 years

3.6 *Steam Turbine Generator*

Quantity:	Two Units
Mfg:	Siemens
Type:	SST-800 back pressure, single-case design with a high-efficiency blade path.

3.7 *Gas Fired Fuel Preheater*

Quantity:	Two Units
Mfg:	TBD
Type:	Natural Gas Fired
Performance:	
Heat Rating	5.00 MMBTU/hr
Stack Height	26.0 feet above grade
Stack Inside Diameter	8.0 inches
Exhaust Temperature	415 ºF

4.0 EXPECTED EMISSIONS

This section discusses the expected emissions from the proposed power blocks. Emissions of both criteria pollutants and hazardous air pollutants were estimated. These emission rates will be used to show that the Marsh Landing Generating Station project will not cause an exceedance of PSD increments, California or Federal AAQS, or significant heath risk measures.

4.1 *Gas Turbine Criteria Pollutant and Hazardous Air Pollutant (HAPs) Emissions*

The emission sources of the project once it becomes operational will include the four power blocks: two Siemens Flex Plant 10 (FP10) and two Siemens Simple Cycle units. Maximum short-term operational emissions from the units were determined from a comparative evaluation of potential emissions corresponding to turbine commissioning, normal operating conditions, and CTG startup/shutdown conditions. The long-term operational emissions from the units were estimated by summing the emissions contributions from normal operating conditions and CTG startup/shutdown conditions. Estimated annual emissions of air pollutants for the units have been calculated based on the expected operating schedule for the units presented below in Tables 4.1-1 and 4.1-2.

The criteria pollutant emission rates and stack parameters provided by the units vendors for three load conditions (60 percent, 85 percent, and 100 percent for FP10 and 60 percent, 75 percent, and 100 percent for the Simple Cycle units) at three ambient temperatures (94°F, 60°F, and 20°F) are presented for FP10 and Simple Cycle units in Table 4.1-3 and Table 4.1-4, respectively.

These cases encompass CTG operations with and without power augmentation, and with and without evaporative cooling of the inlet air to the turbines. The combined scenarios presented in these tables bound the expected normal operating range of each proposed unit.

The expected emissions and durations associated with CTG startup and shutdown events are summarized in Table 4.1-5. Based on vendor information, startup (i.e. the period from initial firing to compliance with emission limits) of the FP10 units is expected within 12 minutes, and the Simple Cycle units within 11 minutes. During a shutdown event, the efficiency of the emission controls will continue to function at normal operating levels down to a load of 60 percent for the FP10s and the Simple Cycle units percent; thus, shutdown periods and emissions are measured from the time this load is reached.

For the FP10, the hours that include a startup event have higher rates of emissions for all criteria pollutants, compared to the hours that include a shutdown event, or to normal operating conditions with fully functioning SCR and CO oxidation catalyst. Thus, the hours that include a startup event were used for the worst-case short- and long-term emission estimates in the air quality dispersion modeling simulations for these pollutants.

For the Simple Cycle units, the hours that include a startup event have higher NO_X, CO, and volatile organic compounds (VOC) emissions, compared to the hours that include a shutdown event, or to normal operating conditions with fully functioning selective catalytic reduction (SCR) and CO oxidation catalyst. For PM_{10}, the hours that include a shutdown event have slightly higher emissions. SO_2 has the highest emissions during normal operation conditions.

The total combined annual emissions from all emission sources of the project are shown in Table 4.1-6 including the two FP10 turbine units and two Simple Cycle units. Annual emissions of all pollutants for the FP10 were calculated for 4,383 hours of operation with 193 startups and 193 shutdowns, with 322 hours of normal operational emissions, 4,000 hours with power augmentation, all calculated at the yearly average temperature of 59°F. The Simple Cycle units emissions were calculated with 877 total hours, with 100 startups, 100 shutdowns, and 849 hours of normal operation at full load at the yearly average temperature of 60°F.

HAPs emissions rate for the units have been calculated based on the expected operating schedule for the units presented below in Tables 4.1-7 and 4.1-8

4.2 *Gas-fired Fuel Preheater Criteria Pollutant and HAPs Emissions*

The preheaters are each rated at of 5.00 MMBTU per hour heat input. The fuel gas heater was conservatively assumed to be operating at full capacity to treat the gas fuel to the turbines. As described in Section 2.0, each fuel preheater has a unique operation schedule depending on the turbines that it serves. Criteria pollutant emissions from the preheaters are shown in Table 4.1-9. HAPs emissions are shown in Table 4.1-10.

Table 4-1 Maximum FP10 Unit Operating Schedule and Stack Parameters

Operating Conditions	Annual Numbers
Number of Starts per Turbine	193
Number of Shutdowns per Turbine	193
Startup Time (min)	12
Shutdown Time (min)	6
Turbine Operation with Power Augmentation (hours)	4,000
Normal Turbine Operation (hours)	322
Total Turbine Operation (hours)	4,383
Stack Height (feet)	150.5
Stack Diameter (feet)	21.33

Table 4-2 Maximum Simple Cycle Unit Operating Schedule and Stack Parameters

Operating Conditions	Annual Numbers
Number of Cold Starts per Turbine	100
Number of Shutdowns	100
Startup Time (min)	11
Shutdown Time (min)	6
Turbine Operation (hours)	849
Total Operation (hours)	877
Stack Height (feet)	150.25
Stack Diameter (feet)	31.33

Table 4-3 1-Hour Operating Emission Rates for FP10 Units

Case	Units	1A	1B	1C	2A	2B	2C	3A	3B	3C	3D	3E	3F
Ambient Temperature	°F	Winter Extreme Minimum: 20°F			Average: 59°F			Summer Design: 94°F					
CTG Load Level	%	100%	85%	60	100%	85%	60%	100%	100%	100%	100%	85%	60%
Evaporative Cooling Status	off/on	Off	Off	Off	Off	Off	Off	On	On	Off	Off	Off	Off
Power Augmentation Status	off/on	Off	Off	Off	Off	Off	Off	On	Off	On	Off	Off	Off
Stack Outlet Temperature	°F	350	346	344	340	337	329	338	348	333	341	346	323
Exit Velocity	fps	70.5	61.5	50.1	64.3	57.0	44.9	65.2	62.5	61.6	59.0	53.4	42.8
NO_X (at 2.0 ppm)	lb/hr	17.4	15.1	12.0	15.8	13.9	10.0	16.3	15.2	15.3	14.3	12.9	10.0
CO (at 3 ppm)	lb/hr	15.9	13.8	10.7	14.6	12.8	9.5	15.0	14.0	14.1	13.1	11.7	9.0
VOC (at 2.0 ppm)	lb/hr	6.2	5.4	4.1	5.6	5.0	3.6	5.8	5.4	5.4	5.0	4.5	3.5
PM_{10}	lb/hr	10.0	8.9	8.0	9.3	8.3	8.0	8.9	8.8	8.5	8.5	7.7	8.0
SO_2 (1 gr/100 scf)	lb/hr	6.4	5.6	4.5	5.8	5.2	4.0	6.0	5.6	5.6	5.3	4.7	3.8

Notes:
CO = carbon monoxide
CTG = combustion turbine generator
fps = feet per second
lb/hr = pounds per hour
NO_X = nitrogen oxide
O_2 = oxygen
PM_{10} = particulate matter 10 microns in diameter
ppm = parts per million
scf = standard cubic feet
SO_2 = sulfur dioxide
VOC = volatile organic compounds

Table 4-4 1-Hour Operating Emission Rates for Simple Cycle Units

Case	Units	1A	1B	1C	2A	2B	2C	3A	3B	3C
Ambient Temperature	**°F**	**Winter Extreme: 20°F**			**Yearly Average: 60°F**			**Summer Design: 94°F**		
CTG Load Level	%	100%	75%	60%	100%	75%	60%	100%	75%	60%
Evap Cooling Status	off/on	Off	Off	Off	85%	OFF	OFF	On	Off	Off
Gas Turbine Outlet Temperature	ºF	1,065	1,065	1,065	1,090	1,090	1,091	1,123	1,123	1,122
Stack Outlet Temperature	ºF	750	750	750	750	750	750	750	750	750
Exit Velocity	fps	70.9	57.6	50.8	68.3	56.6	37.2	65.9	55.4	49.1
NO_X as NO_2 (at 2.5 ppm)	lb/hr	20.83	16.39	13.89	18.89	15.00	12.78	16.94	13.89	11.67
CO (at 3.0 ppm)	lb/hr	15.00	12.00	10.20	13.50	11.25	9.30	12.75	9.75	8.70
VOC (at 2.0 ppm)	lb/hr	5.80	4.60	3.87	5.20	4.20	3.60	4.80	3.80	3.27
PM_{10}	lb/hr	9	8	8	8	8	8	8	8	8
SO_2 (1 gr/100 scf)	lb/hr	6.21	4.90	4.17	5.63	4.51	3.84	5.08	4.11	3.52

Notes:
CO = carbon monoxide
CTG = combustion turbine generator
fps = feet per second
lb/hr = pounds per hour
NO_X = nitrogen oxide
O_2 = oxygen
PM_{10} = particulate matter 10 microns in diameter
ppm = parts per million
scf = standard cubic feet
SO_2 = sulfur dioxide
VOC = volatile organic compounds

Table 4-5 Criteria Pollutant Emission Rates during Startup and Shutdown

Pollutant	FP10 Units				Simple Cycle Units			
	Startup (12 min)		Shutdown (7 min)		Startup (11 min)		Shutdown (6 min)	
	1 hr w/ 1 SU (lb/hr)	Total Emissions (lb/event)	1 hr w/1 SD (lb/hr)	Total Emissions (lb/event)	1 hr w/1 SU (lb/hr)	Total Emissions (lb/event)	1 hr w/1 SD (lb/hr)	Total Emissions (lb/event)
NO_X (2.0 or 2.5 ppm)	38.7	24.8	25.9	10.5	29	12	28.8	10
CO (3 ppm)	279.8	267.1	149.5	135.4	225.25	213	124	110
VOC (2 ppm)	17.7	12.7	10.7	5.2	15.7	11	10.2	5
SO_2 (0.4 gr/100 scf)	2.7	0.6	2.4	0.2	2.19	0.17	2.4	0.15
SO_2 (1 gr/100 scf)	6.7	1.6	6.1	0.4	5.49	0.42	5.7	0.37
PM_{10}	11.1	3.1	9.9	1.1	8.4	1	9.1	1

Notes:

Startup/shutdown duration defined as operation of CTG below 70 percent load for the FP10s or 60 percent load for the Simple Cycle units when gaseous emission rates (lb/hr basis) exceed the controlled rates defined as normal operation

Startup and shutdown SO_2 emissions are calculated based on the total amount of fuel used for each and the emission rate of SO_2 at a winter extreme of 20°F; 100% load

CO = carbon monoxide
NO_X = nitrogen oxide
PM_{10} = particulate matter 10 microns in diameter
SD = shutdown
SO_2 = sulfur dioxide
SU = startup
VOC = volatile organic compounds

Table 4-6 Annual Emissions of Criteria Pollutants for Turbines

Pollutant	Emissions (tons/year)	
	FP10 Units[1]	Simple Cycle Units[2]
NO_X	77.1	18.2
CO	142.4	43.76
VOC	28.5	6.01
SO_2	10.5	1.94
PM_{10}	39.4	6.99

Notes:
[1] FP10 Unit emissions based on 4,383 hours of operation (4,000 hours with power augmentation, 322 hours normal operation, 193 startups, and 193 shutdowns)
[2] Simple Cycle Units emissions based on 877 hours of operation (849 hours of operation with 100 startups and 100 shutdowns)
CO = carbon monoxide
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 micrometers in diameter
VOC = volatile organic compounds
SO_2 = sulfur dioxide

Table 4-7 HAPs Emission Rates from the Operation of Each FP10 Combined Cycle CTG/HRSG

Pollutant	Emission Factor (lb/MMBtu)	Hourly Emission Rate (lb/hr)	Annual Emission Rate (lb/yr)
Ammonia		16.1	7.06E+04
1,3-Butadiene	1.24E-07	2.82E-04	1.23E+00
Acetaldehyde	1.34E-04	3.04E-01	1.33E+03
Acrolein	3.62E-06	8.22E-03	3.60E+01
Benzene	3.26E-06	7.40E-03	3.24E+01
Ethylbenzene	1.75E-05	3.97E-02	1.74E+02
Formaldehyde	3.60E-04	8.18E-01	3.58E+03
Hexane	2.53E-04	5.74E-01	2.52E+03
Propylene	7.53E-04	1.71E+00	7.49E+03
Propylene Oxide	4.67E-05	1.06E-01	4.65E+02
Toluene	6.93E-05	1.57E-01	6.90E+02
Xylenes	2.55E-05	5.79E-02	2.54E+02
Polycyclic Aromatic Hydrocarbons (PAH)			
Benzo(a)anthracene	2.21E-08	5.01E-05	2.20E-01
Benzo(a)pyrene	1.36E-08	3.98E-05	1.32E-01
Benzo(b)fluoranthene	1.10E-08	2.51E-05	1.10E-01
Benzo(k)fluoranthene	1.07E-08	2.44E-05	1.07E-01
Chrysene	2.46E-08	5.59E-05	2.45E-01
Dibenz(a,h)anthracene	2.29E-08	5.21E-05	2.28E-01
Indeno(1,2,3-cd)pyrene	2.29E-08	5.21E-05	2.28E-01
Naphthalene	1.62E-06	3.68E-03	1.61E+01
Total PAHs		**3.98E-03**	**1.74E+01**

Notes:
[1] Hourly and annual emissions based on maximum CTG/HRSG operations.
[2] Annual emissions based on 4,383 hours of operations.
[3] Emission factors obtained from the CATEF database for natural-gas–fired combustion turbines. Formaldehyde, Benzene, and Acrolein emission factors are from the Background document for AP-42, Section 3.1, Table 3.4-1 for a natural-gas–fired combustion turbine with a carbon monoxide catalyst.
[4] Ammonia emission rate based on an exhaust ammonia limit of 5 parts per million by volume at 15 percent oxygen provided by the turbine vendor.
[5] Used a HHV of 1,024 British thermal units per standard cubic foot to convert emission factor units.

Table 4-8 HAPs Emission Rates from the Operation of Each 5000F Simple Cycle CTG

Pollutant	Emission Factor (lb/MMBtu)	Hourly Emission Rate (lb/hr)	Annual Emission Rate (lb/yr)
Ammonia		32.91	2.89E+04
1,3-Butadiene	1.24E-07	2.73E-04	2.40E-01
Acetaldehyde	1.34E-04	2.95E-01	2.58E+02
Acrolein	3.62E-06	7.97E-03	6.99E+00
Benzene	3.26E-06	7.18E-03	6.30E+00
Ethylbenzene	1.75E-05	3.85E-02	3.38E+01
Formaldehyde	3.60E-04	7.93E-01	6.95E+02
Hexane	2.53E-04	5.57E-01	4.88E+02
Propylene	7.53E-04	1.66E+00	1.45E+03
Propylene Oxide	4.67E-05	1.03E-01	9.02E+01
Toluene	6.93E-05	1.53E-01	1.34E+02
Xylenes	2.55E-05	5.61E-02	4.92E+01
Polycyclic Aromatic Hydrocarbons (PAH)			
Benzo(a)anthracene	2.21E-08	4.86E-05	4.26E-02
Benzo(a)pyrene	1.36E-08	3.98E-05	1.32E-01
Benzo(b)fluoranthene	1.10E-08	2.43E-05	2.13E-02
Benzo(k)fluoranthene	1.07E-08	2.37E-05	2.07E-02
Chrysene	2.46E-08	5.42E-05	4.75E-02
Dibenz(a,h)anthracene	2.29E-08	5.05E-05	4.43E-02
Indeno(1,2,3-cd)pyrene	2.29E-08	5.05E-05	4.43E-02
Naphthalene	1.62E-06	3.57E-03	3.13E+00
Total PAHs		**3.86E-03**	**3.48E+00**

Notes:
1 Hourly and annual emissions based on maximum CTG operations
2 Annual emissions based on 877 hours of operations.
3 Emission factors obtained from the CATEF database for natural-gas–fired combustion turbines. Formaldehyde, Benzene, and Acrolein emission factors are from the Background document for AP-42, Section 3.1, Table 3.4-1 for a natural-gas–fired combustion turbine with a carbon monoxide catalyst.
4 Ammonia emission rate based on an exhaust ammonia limit of 10 parts per million by volume at 15 percent oxygen provided by the turbine vendor.
5 Used a HHV of 1,024 British thermal units per standard cubic foot to convert emission factor units.

Table 4-9 Annual Emissions of Criteria Pollutants for the Preheaters

	S-5 (Serving FP-10 Units S-1 and S-2)		S-6 (Serving Simple Cycle Units S-3 and S-4)	
Pollutant	lbs/yr/unit	tons/yr/unit	lbs/yr/unit	tons/yr/unit
CO	752	0.376	150.5	0.075
NO_x	657	0.329	131.6	0.066
PM_{10}	64.5	0.032	12.9	0.006
SO_2*	24.5	0.012	4.9	0.002
VOC	60.2	0.030	12.0	0.006

*based on 0.4 gr total S / 100 scf

Table 4-10 HAPs Emission Rates from the Operation of Each Fuel Gas Preheater

Pollutant	Emission Factor (lb/MMBtu)	Hourly Emission Rate (lb/hr)	Annual Emission Rate (lb/yr)
Acetaldehyde	1.37E-05	6.84E-05	3.00E-01
Acrolein	4.73E-06	2.36E-05	1.04E-01
Benzene	1.09E-05	5.47E-05	2.40E-01
Ethylbenzene	2.20E-06	1.10E-05	4.82E-02
Formaldehyde	7.23E-05	3.61E-04	1.58E+00
Propylene	2.29E-04	1.15E-03	5.03E+00
Toluene	2.88E-05	1.44E-04	6.31E-01
Xylenes	1.40E-05	6.98E-05	3.06E-01
Polycyclic Aromatic Hydrocarbons (PAH)			
Benzo(a)anthracene	1.91E-09	9.57E-09	4.19E-05
Benzo(a)pyrene	9.57E-10	4.79E-09	2.10E-05
Benzo(b)fluoranthene	1.11E-09	5.57E-09	2.44E-05
Benzo(k)fluoranthene	9.67E-10	4.83E-09	2.12E-05
Chrysene	1.36E-09	6.79E-09	2.97E-05
Dibenz(a,h)anthracene	8.96E-10	4.48E-09	1.96E-05
Indeno(1,2,3-cd)pyrene	1.14E-09	5.71E-09	2.50E-05
Naphthalene	1.09E-06	5.47E-06	2.40E-02
Total PAHs		**5.51E-06**	**2.42E-02**

Notes:

1 Hourly and annual emissions based on maximum heater fuel energy consumption of 5 MMBtu/hour.
2 Annual emissions based on 4,383 hours of operations.
3 Emission factors obtained from the average species data from CATEF database for natural-gas–fired heaters (without controls).
4 Used a HHV of 1,024 British thermal units per standard cubic foot to convert emission factor units.

5.0 LAWS, ORDINANCES, AND REGULATIONS

The applicable laws, ordinances, regulations, and standards (LORS) related to the potential air quality impacts from the project are described below. These LORS are administered (either independently or cooperatively) by the BAAQMD, the U.S. EPA Region IX, the CEC, and the CARB.

5.1 *Ambient Air Quality Standards*

U.S. EPA, in response to the federal CAA of 1970, established NAAQS in 40 CFR Part 50. NAAQS include both primary and secondary standards for six "criteria" pollutants. These criteria pollutants are O_3, CO, NO_2, SO_2, PM_{10}, and Pb. Primary standards were established to protect human health, and secondary standards were designed to protect property and natural ecosystems from the effects of air pollution.

The 1990 Clean Air Act Amendments (CAAA) established attainment deadlines for all designated areas that were not in attainment with the NAAQS. In addition to the NAAQS described above, a new federal standard for $PM_{2.5}$ and a revised O_3 standard were promulgated in July 1997. The new federal standards were challenged in a court case during 1998.

The court required revisions in both standards before U.S. EPA could enforce them. The U.S. Supreme Court upheld an appeal of the District Court decision in February 2001. Under an interim policy, the preexisting federal PM_{10} and 1-hour O_3 standards would continue to be implemented for the next several years until any required actions by U.S. EPA were completed. In 1997, EPA established annual and 24-hour NAAQS for $PM_{2.5}$ for the first time. In 2006, the federal annual PM_{10} standard was revoked by the U.S. EPA due to a lack of evidence linking health problems to long-term exposure to coarse particle pollution. The 3-year average of the 98th percentile of 24-hour PM_{10} concentrations (35 $\mu g/m^3$) was effective on December 17, 2006. The State of California has adopted CAAQS that are in some cases more stringent than the federal NAAQS. The NAAQS and CAAQS relevant to the proposed project are summarized in Table 5-1.

The U.S. EPA, the CARB, and the local air pollution control districts determine air quality attainment status by comparing local ambient air quality measurements from the state or local ambient air monitoring stations with the NAAQS and CAAQS. Those areas that meet ambient air quality standards are classified as "attainment" areas; areas that do not meet the standards are classified as "nonattainment" areas. Areas that have insufficient air quality data may be identified as unclassifiable areas. These attainment designations are determined on a pollutant-by-pollutant basis. The proposed project site is designated a federal nonattainment area for O_3 based on air quality monitoring data showing exceedances of the NAAQS. The proposed project vicinity is designated a state nonattainment area for O_3, based on air quality monitoring data showing exceedances of the CAAQS. Table 5-2 presents the attainment status (both federal and state) for Contra Costa County in the BAAQMD.

BAAQMD Regulation 2-2, New Source Review (NSR) requires that the emissions from a new or modified source will not cause a violation of any Federal or State AAQS.

5.2 *Prevention of Significant Deterioration Requirements*

In addition to the ambient air quality standards described above (NAAQS), the federal PSD program has been established to protect deterioration of air quality in those areas that already meet national ambient air quality standards. The BAAQMD has been delegated PSD authority by the EPA. Specifically, the PSD program establishes allowable concentration increases for attainment pollutants due to new emission sources that are classified as major sources. These increases allow economic growth, while preserving the existing air quality, protecting public health and welfare, and protecting Class I areas (national parks and wilderness areas).

The PSD regulations define a "major stationary source" as any source type belonging to a list of 28 source categories that emits, or has the "potential to emit" 100 tons per year or more of any pollutant regulated under the CAA, or any other source type that has the potential to emit such pollutants in amounts equal to or greater than 250 tons per year. If a source is considered major for PSD purposes because of one pollutant, then PSD review is applicable for those other pollutants emitted from the source in amounts greater than the PSD significance levels. The PSD regulations require major stationary sources to undergo a preconstruction review that includes an analysis and implementation of BACT (see Section 8.0), a PSD increment consumption analysis, an ambient air quality impact analysis (see Section 7.0), and analysis of AQRVs (impacts on visibility and vegetation). The MLGS is subject to these requirements.

The incremental proposed project emissions for SO_2, NO_X, PM_{10}, VOC, and CO are as shown in Table 5-3 and compared with the PSD significance thresholds. The project emissions of NO_X, PM_{10}, VOC, and CO would be above these PSD triggers; thus, the Applicant must demonstrate through modeling (except for VOC for which no AAQS apply) that such emissions will not interfere with the attainment or maintenance of the applicable NAAQS and will not cause exceedances of the applicable PSD increments shown in Table 5-4. For project emissions of CO that would exceed the trigger levels, the Applicant must demonstrate through modeling that the increase in emissions would not interfere with the attainment or maintenance of the CO NAAQS. Allowable PSD increments for SO_2 and NO_X in Class I and II areas are summarized in Table 5-4.

Point Reyes National Sea Shore is the only Class I area within 100 km of the project site and within the boundary of BAAQMD. All other areas are Class II areas; there are no Class III areas within the BAAMD. The Applicant contacted the National Park Service administrator for Point Reyes National Seashore, the only Class I area located within 100 km of the proposed project. The National Park Service determined a Class I impact analysis is not required for this project. They stated:

> "The National Park Service Air Resources Division has reviewed the information you provided below regarding the proposed Contra Costa Generation Project which is proposing to locate some 82 kilometers east of the Point Reyes National Seashore, a Class I area administered by the National Park Service. Due to the low amount of proposed emissions and the distance to Point Reyes National Seashore, the National Park Service does not request that a Class I increment analysis and an Air Quality Related Values analysis be performed for the Contra Costa Generation Project's PSD permit. Please forward this e-mail to the permitting agency for their notification. The permitting agency may contact the National Park Service Air Resources Division if it has any questions on this issue."(Notar, 2008)

5.3 *Acid Rain Program Requirements*

Title IV of the CAAA applies to sources of air pollutants that contribute to acid rain formation, including certain sources of SO_2 and NO_X emissions. Title IV is implemented by the U.S. EPA under 40 CFR 72, 73, and 75. Allowances of SO_2 emissions are set aside in 40 CFR 73. Sources subject to Title IV are required to obtain SO_2 allowances, to monitor their emissions, and obtain SO_2 allowances when a new source is permitted. Sources such as the proposed project that use pipeline-quality natural gas are exempt from many of the acid rain program requirements. However, these sources must still estimate SO_2 and carbon dioxide (CO_2) emissions, and monitor NO_X emissions with certified CEMS. All subject facilities must submit an acid rain permit application to U.S. EPA within 24 months of commencing operation.

5.4 *New Source Performance Standards*

New source performance standards (NSPS) have been established by U.S. EPA to limit air pollutant emissions from certain categories of new and modified stationary sources. The NSPS regulations are contained in 40 CFR Part 60 and cover many different industrial source categories. Stationary gas turbines are regulated under Subpart KKKK. The enforcement of NSPS has been delegated to the BAAQMD, and the NSPS regulations are incorporated by reference into the District's Regulation X. In general, local emission limitation rules or BACT requirements in California are far more restrictive than the NSPS requirements. For example, the controlled NO_X emission rate from the project's gas turbines of less than 0.08 pound (lb) of NO_X per MW-hour will be well below the Subpart KKKK requirement of 0.39 lb of NO_X per MW-hour. Similarly, the projected maximum SO_2 emissions from the MLGS gas turbines will be about 0.011 lb of SO_2 per MW-hour, which is substantially less than the Subpart KKKK requirement of 0.58 lb of SO_2 per MW-hour.

NSPS fuel requirements for SO_2 will be satisfied by the use of natural gas, and emissions and fuel monitoring that will be performed to meet the requirements of BACT will comply with NSPS, acid rain, and other regulatory requirements.

5.5 *Federally Mandated Operating Permits*

Title V of the CAA requires U.S. EPA to develop a federal operating permit program that is implemented under 40 CFR 70. This program is administered by BAAQMD under Regulation II, Rules 6. Permits must contain emission estimates based on potential-to-emit, identification of all emission sources and controls, a compliance plan, and a statement indicating each source's compliance status. The permits must also incorporate all applicable federal, state, or air quality control district orders, rules and regulations. Because the facility will undergo new construction and operations, the proposed project will apply for a new Title V permit.

5.6 *Power Plants Siting Requirements*

Under the California Environmental Quality Act (CEQA), the CEC has been charged with assessing the environmental impacts of each new power plant and considering the implementation of feasible mitigation measures to prevent potential significant impacts. CEQA Guidelines [Title 14, California Administrative Code, Section 15002(a)(3)] state that the basic purpose of CEQA is to "prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible."

The CEC siting regulations require that, unless certain conditions justifying an override are shown, a new power plant can only be approved if the proposed project complies with all federal, state, and local air quality rules, regulations, standards, guidelines, and ordinances that govern the construction and operation of the proposed project. A project must demonstrate that facility emissions will be appropriately controlled to mitigate significant impacts from the project and that it will not jeopardize attainment and maintenance of the state and federal AAQS. Cumulative impacts, impacts due to pollutant interaction, and impacts from non-criteria pollutants must also be considered.

5.7 *Air Toxic "Hot Spots" Program*

As required by the California Health and Safety Code Section 44300 (originally Assembly Bill 2588 – Air Toxics "Hot Spots" Information and Assessment Act). This program was created in 1987 to develop a statewide inventory of air toxics emissions from stationary sources. Applicable facilities must prepare the following: (1) an emissions inventory plan identifying air toxics; (2) an emission inventory report quantifying air toxics emissions; and (3) a health risk assessment, if air toxics emissions are at high levels. Facilities whose air toxics pose a significant health risk must also prepare and implement risk reduction plans. This requirement is applicable only after the start of operations. Section 9.0, Public Health, indicates that air toxics impacts from the proposed project would be insignificant.

5.8 *New Source Review Requirements*

NSR rules establish the criteria for siting new and modified emission sources. BAAQMD has been delegated authority for NSR rule development and enforcement; the district's NSR rules are contained in Regulation 2, Rule 2. There are three basic requirements within NSR rules. First, BACT must be applied to any new source that emits above specified threshold quantities (see Section 8.0). Second, all potential increases from the sources above must be offset by real, quantifiable, surplus, permanent, and enforceable emission decreases in the form of emission reduction credits (ERCs) (see Section 6.0). Third, ambient air quality impact assessment must be conducted to confirm that the proposed MLGS project does not cause or contribute to a violation of federal or California AAQS (see Section 7.0) or jeopardize public health (see Section 9.0)

5.9 *Bay Area Air Quality Management District Requirements*

The following paragraphs outline the BAAQMD rules and regulations that apply to the proposed project:

Regulation I–General Provisions and Definitions

Regulation I, Section 301 – Public Nuisance

The releases of air contaminants anticipated under the proposed project are not expected to "cause injury, detriment, nuisance or annoyance to any considerable number of persons or the public." In addition, none of the proposed project's sources of air contaminants are expected to endanger "the comfort, repose, health or safety of any such persons or the public, or cause injury or damage to business or property." The air quality impact analysis is designed to ensure that the proposed project will not cause any public nuisance.

Regulation II–Permits

Regulation II, Rule 1, Sections 301 and 302—Authority to Construct and Permit to Operate

Mirant Marsh Landing, LLC will submit an application to the district to obtain an ATC and PTO for the combustion gas turbines.

Regulation II, Rule 2—New Source Review

The purpose of this rule is to provide for the review of new and modified sources and provide mechanisms.

Regulation 2, Rule 2, Section 301 ("Best Available Control Technology Requirement") requires BACT for a new or modified sources that have the potential to emit 10 pounds or more per highest day of VOCs, non-precursor organic compounds (NPOCs), NO_X, SO_2, PM_{10}, or CO.

Regulation 2, Rule 2, Section 302 ("Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides") stipulates that federally enforceable emission offsets are required for VOC and NO_X emission increases from permitted sources which will emit more than 35 tons per year or more on a pollution-specific basis. For these facilities that emit more than 35 tons per year or more of NO_X or VOC, offsets are provided at a ratio of 1.15 to 1.0. The project is expected to emit more than 35 tons per year of NO_X and VOC, so emission offsets would be provided as necessary. Section 303 ("Offset Requirement, PM_{10} and Sulfur Dioxide") stipulates that emission offsets would be provided at a ratio of 1:1 for facilities that will result in a cumulative increase minus any contemporaneous emission reduction credits at the facility, in excess of 1.0 ton per year of PM_{10} or sulfur dioxide. The facility is expected to emit greater than 100 tons per year of PM_{10}, so emission offsets will be provided per this regulation. However, the facility is expected to release less than 100 tons per year of SO_2, so no emission offsets are required for this pollutant. Details of emission offset strategy are given in Section 6.0.

Pursuant to Regulation 2-2-414-1 ("PSD Air Quality Analysis"), air quality analysis was performed including meteorological and topographic data for the proposed project. This analysis includes ensuring that the emission increases caused by the facility will not cause or contribute to a violation of an air quality standard or an exceedance of any applicable PSD increment. The protocol and the results for this modeling is presented in Section 7.0.

Pursuant to Regulation 2-2-417 ("Visibility, Soils, and Vegetation Analysis"), an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the new or modified source and the general commercial, residential, industrial and other growth associated with the source or modification needs to be submitted with the application. The applicant need not provide an analysis of the impact on vegetation if it has no significant commercial or recreational value. Analysis of visual impacts is discussed in Section 7.0.

Regulations 2-2-304 and 2-2-305 ("PSD Requirements" and "Carbon Monoxide Modeling Requirement") specify the incremental emission triggers for SO_2, NO_x, PM_{10}, and CO. For project emissions of SO_2, NO_x, or PM_{10} above these PSD triggers, the applicant must demonstrate through modeling that no air quality standard will be exceeded. For project emissions of CO which exceed the trigger levels, the applicant must demonstrate through modeling that the increase in emissions will not interfere with the attainment or maintenance of the CO NAAQS. Section 7.0, discusses these PSD requirements further.

Regulation 2, Rule 3, ("Power Plants") contains procedures for the review and standards for the approval of authorities to construct power plants. This regulation will be complied with through the submittal of a stand alone application for an Authority to Construct to BAAQMD.

Pursuant to Regulation 2, Rule 7 ("Acid Rain"), the gas turbine units will be subject to the requirements of Title IV of the Federal Clean Air Act. Allowances of SO_2 emissions are set aside in 40 CFR 73. See Section 5.3 for a discussion of compliance.

Regulation III–Fees

Regulation III identifies the fees that are applicable to permit modifications, new facilities, and permitted emissions. The required fees will be submitted with the application for Permit to Construct/Permit to Operate in compliance with this rule.

Regulation VI–Particulate Matter and Visible Emissions

The proposed project will utilize the following to minimize the release of particulate matter and diminish the visibility of emissions:

Ultra low-NO_x burner technology and proper combustion practices;

Natural gas as the combustion fuel for the proposed gas turbines; and

The emission sources of the project are expected to comply with the standards set forth in Regulation 6:

No visible emission from any of the sources will be as dark or darker than No. 1 on the Ringelmann Chart, or of such opacity as to obscure an observer's view to an equivalent or greater degree for a period more of than three minutes in any hour (Regulation 6, Section 301);

No visible emission from any of the sources will be equal to or greater than 20 percent opacity as perceived by an opacity sensing device for a period of more than three minutes in any hour (Regulation 6, Section 302);

No emission from any of the sources will contain particulate matter in excess of 0.15 grains per dry cubic foot of exhaust gas volume (Regulation 6, Section 310).

Calculated in accordance with Regulation 6-310.3, the worst-case grain loading from operation of the turbines was calculated to be less than 0.05 grains per dry standard cubic foot of exhaust gas. Therefore, the grain loading from the turbines is expected to be in compliance with this regulation. Particulate matter associated with the construction of the facility is exempt from district permit requirements but is subject to Regulation 6. It is expected that the CEC will impose conditions on construction activities that will require the use of water or chemical dust suppressants to minimize PM_{10} emissions and prevent visible particulate emissions.

Regulation VII–Odorous Substances

Regulation 7, Rule 302 prohibits the discharge of any odorous substances which remain odorous at the property line after dilution with four parts of odor-free air. Regulation 303 prohibits the discharge of ammonia in concentrations greater than 5,000 ppm. Because the ammonia emissions from the SCR units will be limited to 5 ppmvd for the combined cycle units and 10 ppmvd for the simple cycle units each at 15 percent O_2, the proposed project is expected to be in compliance with this regulation.

Regulation VIII–Organic Compounds

This regulation limits the emission of organic compounds to the atmosphere. The proposed project is exempt from this regulation per 8-2-110 because natural gas is the only fuel used in the project. Solvents used in cleaning and maintenance are expected to comply with Regulation 8, Rule 4, by emitting less than 5 tpy of VOCs.

Regulation IX–Inorganic Gaseous Pollutants

This regulation emission limits for various compounds.

Regulation 9, Rule 1, “Sulfur Dioxide”: Section 301 (“Limitations on Ground Level Concentrations”) limits SO_2 emissions to 0.5 ppm continuously for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Modeling results indicate that the maximum concentration of SO_2 released in one hour result in ground level concentrations less than 3 ppb. Section 302 (“General Emission Limitation”) prohibits emissions from a gas stream containing SO_2 in excess of 300 ppm (dry). Expected emissions of SO_2 are not expected to exceed 20 ppm.

Regulation 9, Rule 9, “Nitrogen Oxides from Stationary Gas Turbines”: General emission limits in 9-9-301.3 states that gas turbines rated at 10.0 MW and over, with SCR, shall not exceed 9 ppmv, except that, for non-gaseous fuel firing during natural gas curtailment or short testing periods, the limit is 25 ppmv. The project turbines are expected to comply with this rule.

Table 5-1 National and California Ambient Air Quality Standards

Pollutant	Averaging Time	NAAQS[1]		CAAQS[2]
		Primary[3,4]	**Secondary[3,5]**	**Concentration[3]**
Ozone (O_3)	1-Hour	Revoked [8]	Same as Primary Standard	0.09 ppm (180 µg/m^3)
	8-Hour	0.075 ppm		0.07 ppm (137 µg/m^3)
Carbon Monoxide (CO)	8-Hour	9 ppm (10 mg/m^3)	None	9.0 ppm (10 mg/m^3)
	1-Hour	35 ppm (40 mg/m^3)		20 ppm (23 mg/m^3)
Nitrogen Dioxide (NO_2)[9]	Annual Average	0.053 ppm (100 µg/m^3)	Same as Primary Standard	0.030 ppm (57 µg/m^3)
	1-Hour	-		0.18 ppm (339 µg/m^3)
Sulfur Oxides (SO_2)	Annual Average	0.03 ppm (80 µg/m^3)	-	-
	24-Hour	0.14 ppm (365 µg/m^3)	-	0.04 ppm (105 µg/m^3)
	3-Hour	-	0.5 ppm (1300 µg/m^3)	-
	1-Hour	-	-	0.25 ppm (655 µg/m^3)
Suspended Particulate Matter (PM_{10})	24-Hour	150 µg/m^3	Same as Primary Standard	50 µg/m^3
	Annual Arithmetic Mean	Revoked [6]		20 µg/m^3
Fine Particulate Matter ($PM_{2.5}$) [7]	24-Hour	35 µg/m^3	Same as Primary Standard	-
	Annual Arithmetic Mean	15 µg/m^3		12 µg/m^3
Lead (Pb)	30-Day Average	-	-	1.5 µg/m^3
	Quarterly Average	1.5 µg/m^3	Same as Primary Standard	-
Hydrogen Sulfide (HS)	1-Hour	No Federal Standards		0.03 ppm (42 µg/m^3)
Sulfates (SO_4)	24-Hour			25 µg/m^3
Visibility Reducing Particles	8-Hour (10 am to 6 pm, Pacific Standard Time)			In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent.

µg/m^3 = micrograms per cubic meter; mg/m^3 – milligram per cubic meter; ppm – parts per million
Source: U.S. EPA-NAAQS (http://www.epa.gov/air/criteria.html); CARB-CAAQS (http://www.arb.ca.gov/aqs/aaqs2.pdf)

1. National standards (other than ozone, particulate matter, and those based on annual averages or annual arithmetic mean) are not to be exceeded more than once a year. The ozone standard is attained when the fourth highest 8-hour concentration in a year, averaged over 3 years, is equal to or less than the standard. For PM_{10}, the 24-hour standard is attained when the expected number of days per calendar year with a 24-hour average concentration above 150 µg/m^3 is equal to or less than one. For $PM_{2.5}$, the 24-hour standard is attained when 98 percent of the daily concentrations, averaged over 3 years, are equal to or less than the standard. Contact U.S. EPA for further clarification and current federal policies.
2. California standards for ozone, carbon monoxide (except Lake Tahoe), sulfur dioxide (1 and 24 hour), nitrogen dioxide, suspended particulate matter—PM_{10}, $PM_{2.5}$, and visibility-reducing particles, are values that are not to be exceeded. All others are not to be equaled or exceeded. California ambient air quality standards are listed in the Table of Standards in Section 70200 of Title 17 of the California Code of Regulations.
3. Concentration expressed first in units in which it was promulgated. Equivalent units given in parentheses are based upon a reference temperature of 25°C and a reference pressure of 760 torr. Most measurements of air quality are to be corrected to a reference temperature of 25°C and a reference pressure of 760 torr; ppm in this table refers to ppm by volume, or micromoles of pollutant per mole of gas.
4. National Primary Standards: The levels of air quality necessary, with an adequate margin of safety to protect the public health.
5. National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant.
6. Due to a lack of evidence linking health problems to long-term exposure to coarse particle pollution, the agency revoked the annual PM_{10} standard in 2006 (effective December 17, 2006).
7. To attain this standard, the 3-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed 35 µg/m^3 (effective December 17, 2006)
8. On June 15, 2005, the 1-hour ozone standard (0.12 ppm) was revoked for all areas except the 8-hour ozone nonattainment Early Action Compact Areas (EAC) areas.

Table 5-2 Attainment Status for Contra Costa County with Respect to Federal and California Ambient Air Quality Standards

Pollutant	Federal Attainment Status	State Attainment Status
Ozone	Nonattainment	Nonattainment
CO	Unclassified/Attainment	Attainment
NO_2	Unclassified/Attainment	Attainment
SO_2	Attainment	Attainment
PM_{10}	Unclassified	Nonattainment
$PM_{2.5}$	Unclassified/Attainment	Nonattainment
Lead	Unclassified	Attainment

Source: National Area Designations and Proposed 2006 State Area Designations, CARB (http://www.arb.ca.gov/desig/adm/adm.htm)
Notes:
CO = carbon monoxide
NO_2 = nitrogen dioxide
SO_2 = sulfur dioxide
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter

Table 5-3 PSD Emission Threshold Triggers for New Stationary Sources

Pollutant	Significant Thresholds (tpy)	Project Emissions (tpy)	PSD Triggered by Project?
CO	100	186.1	Yes
SO_2	40	12.5	No
NO_X	40	95.3	Yes
PM_{10}	15	46.4	Yes
VOCs	40	34.5	No

Source: BAAQMD rule 2 (http://www.baaqmd.gov/dst/regulations/rg0202.pdf)
Project emissions include all emissions from natural gas.
Notes:
tpy = tons per year
CO = carbon monoxide
SO_2 = sulfur dioxide
NO_X = nitrogen oxide(s)
PM_{10} = particulate matter less than 10 microns in diameter
VOCs = volatile organic compounds

Table 5-4 Allowable PSD Increments for SO_2, NO_2, and PM_{10}

Pollutant	Averaging Times	Maximum Allowable Increase (Micrograms Per Cubic Meter)
Class I		
PM_{10}	PM_{10} Annual arithmetic mean	4
	PM_{10} 24-hr maximum	8
SO_2	Annual arithmetic mean	2
	24-hr maximum	5
	3-hr maximum	25
NO_2	Annual arithmetic mean	2.5
Class II		
PM_{10}	PM_{10} Annual arithmetic mean	17
	PM_{10} 24-hr maximum	30
SO_2	Annual arithmetic mean	20
	24-hr maximum	91
	3-hr maximum	512
NO_2	Annual arithmetic mean	25

Source: BAAQMD rule 2 (http://www.baaqmd.gov/dst/regulations/rg0202.pdf)
Notes:
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than 10 microns in diameter
SO_2 = sulfur dioxide

6.0 EMISSION OFFSETS

Per Bay Area Air Quality Management District Regulations 2-2-215, 302, and 303, the project is required to provide emission offsets in the form of emissions reduction credits (ERC) for increases in emissions of nonattainment pollutants in excess of specified thresholds that will result from the operation of the proposed facility on a pollutant-specific basis. Per District Regulations 2-2-302 VOC and NOx ERCs are required to be provided at an offset ratio of 1.0:1.0 or 1.15:1.0, depending on the amount of emissions levels. Since both VOC and NO_X are ozone precursors, Regulations 2-2-302.2 allows ERCs of VOCs to be used as an interpollutant offset for NO_X, at the required offset ratios.

Sections 2-2-304 and 2-2-305 impose emissions offset requirements, or require project denial, if SO_2, NO_2, $PM_{10/2.5}$, or CO air quality modeling results indicate emissions will either interfere with the attainment or maintenance of the applicable AAQS, or exceed PSD increments. The modeling analyses show that facility emissions will not interfere with the attainment or maintenance of the applicable air quality standards.

For major sources subject to PSD review, Regulation 2-2-305 requires an applicant to either demonstrate through modeling that its emissions will comply with the CO AAQS, or provide contemporaneous emission offsets. The project will not cause a violation of any applicable CO ambient air quality standard. Therefore, CO emission offsets are not required.

Mirant California emission offsets inventory and estimated required ERCs due to project operations are shown in Table 6-1 and Table 6-2, respectively. As shown in Table 6-1, Mirant California demonstrated its capability to provide the required emission offsets for the project.

Table 6-1 Emission Reduction Credit Certificates Owned by Mirant California

Certificate No	756	831	863	918	**Total**
VOC (tons/yr)	0.390	72.280	5.300	0.000	77.970
NO_X (tons/yr)	1.173	66.060	247.500	171.000	485.733
SO_2 (tons/yr)	0.000	0.000	130.179	0.000	130.179
CO (tons/yr)	14.602	450.600	114.000	0.000	579.202
PM_{10} (tons/yr)	6.443	202.530	25.270	0.000	234.243
Issued Date	19-Jul-01	28-Aug-02	16-Jan-03	17-Mar-04	
Application No.	1000	5800	6925	9283	
Source Location	Hudson ICS	Crown Zellerbach Corporation	Pacific Gas & Electric Company	Crown Zellerbach Corporation	
	San Leandro, CA	Antioch, CA	Martinez, CA	Antioch, CA	
Source: BAAQMD Emission Bank Status Web Page <http://www.baaqmd.gov/pmt/emissions_banking/banking.htm>					

Table 6-2 Estimated Emission Credit Requirement to Offset Project Emissions

Pollutant	**Total Marsh Landing Turbine Potential Emissions (ton/yr)**	**New Source Review Offset Ratio**	**Offsets Required (ton/yr)**	**Current ERC Holdings (ton/yr)**	**Holdings After Offsets are Deducted (ton/yr)**
NO_X	95.7	1.15	110.0	485.7	375.7
CO	186.5	0	0.0	579.2	579.2
VOC	34.5	1.15	39.7	78.0	38.3
SO_2	12.5	1	12.5	130.2	117.7
PM_{10}	46.4	1	46.4	234.2	187.8

Notes:
Offset ratios are 1.15 : 1 for NOx and VOC emissions on a pollutant specific basis, for each pollutant (facility wide) over 35 tons per year. Below 35 tons is 1 : 1.
Offset ratios are 1 : 1 for remaining criteria pollutants.
0.4 gr/100scf annual average natural gas sulfur

7.0 AMBIENT AIR QUALITY AND PSD ANALYSIS

7.1 *Air Dispersion Modeling*

The purpose of the air quality impact analysis is to evaluate whether criteria pollutant emissions resulting from the proposed project would cause or contribute significantly to a violation of a CAAQS or NAAQS, or contribute significantly to degradation of air quality–related values in Class I areas. Mathematical models designed to simulate the atmospheric transport and dispersion of airborne pollutants are used to quantify the maximum expected impacts of project emissions for comparison with applicable regulatory criteria. The impacts from operations would be associated with natural gas combustion in the CTG units and fuel gas preheaters.

The air quality modeling methodology described in this section has been documented in a formal modeling protocol, which has been submitted for comments to CEC and BAAQMD. The modeling approaches used to assess various aspects of the proposed project's potential impacts to air quality are discussed below.

Model and Model Option Selections

The impacts of project operations emissions on criteria pollutant concentrations in the area adjacent to the proposed project site were evaluated using the AERMOD dispersion model (Version 07026). AERMOD is appropriate because it has the ability to assess dispersion of emission plumes from multiple point, area, or volume sources in flat, simple, and complex terrain, while utilizing sequential hourly meteorological input data. The regulatory default options were used, including building and stack tip downwash, default wind speed profiles, exclusion of deposition and gravitational settling, consideration of buoyant plume rise, and complex terrain.

For the AERMOD simulations to evaluate commissioning impacts of NO_2 concentrations, the ozone-limiting method option of the model was used to take into account the role of ambient ozone in limiting the conversion of emitted NO_X (which occurs mostly in the form of NO) to NO_2, the pollutant regulated by ambient standards. The input data to the AERMOD-OLM model includes representative hourly ozone monitoring data for the same years corresponding to the meteorological input record. These simulations used the ozone data from the BAAQMD Bethel Island monitoring station for the years 2000-2002 and 2004-2005.

To evaluate whether urban or rural dispersion parameters should be used in the model simulations, an analysis of land use adjacent to the proposed project site was conducted in accordance with Section 8.2.8. of the *Guideline on Air Quality Models* (U.S. EPA, 2003), *Correlation of Land Use and Cover with Meteorological Anomalies* (Auer, 1978), AERMOD implementation guide (U.S. EPA, 2005), and its addendum (U.S. EPA, 2006a). Based on the Auer land use classification procedure, more than 50 percent of the area within a 1.86-mile (3-kilometer) radius of the proposed project site is appropriately classified as rural. Thus, according to the U.S. EPA AERMOD implementation guide, AERMOD's rural option was selected. Land use parameter values when processing the onsite Contra Costa meteorological data are discussed in the Meteorological Data section.

Building Wake Effects

The effects of building wakes (i.e., downwash) on the plumes from the proposed project's CTGs were evaluated in the modeling for operational emissions, in accordance with U.S. EPA guidance (U.S. EPA, 1985). Location coordinates and dimensions of the buildings within new and existing areas of the site that could potentially cause plume downwash effects for the new stacks were determined for different wind directions using the U.S. EPA Building Profile Input Program – Prime (BPIP-Prime) (Version 04274). The following structures were identified within the proposed project site to be included in the downwash analysis (the number of multiple identical structures are denoted with parenthesis):

- CTG-HRSGs (2)
- CTG-SCRs (2)
- Air-cooled heat exchangers (2)
- Gas turbine inlet filters (4)
- Waste water storage tank
- RO permeate storage tank
- Demin. water storage tank
- Raw water storage tank
- Buildings associated with existing CCPP CTGs (4)
- Existing Gateway CTG-HRSGs (2)
- Existing Gateway air cooled condenser
- Three existing CCPP oil tanks

The results of the BPIP-Prime analysis were included in the AERMOD input files to enable downwash effects to be simulated. Input and output electronic files for the BPIP-Prime analysis are included with those from all other dispersion modeling analyses in a DVD accompanying this application package.

Meteorological Data

Onsite meteorological data have been collected by PG&E. Excellent data capture occurred for the years 2000 through 2002 and 2004 through 2005, and thus these years were selected to be used to create the AERMET data input file. Onsite data for 2003 had inadequate data capture, and therefore were not used in AERMET. The PG&E data were collected within the boundary of the PG&E 230-kV switchyard adjacent to the Contra Costa Power Plant (CCPP) and the MLGS site, and meet the U.S. EPA criteria for representativeness (U.S. EPA, 1995), as follows:

> *Proximity*: The data were collected within the boundary of the CCPP site, and thus meet the criteria for proximity.
>
> *Complexity of Terrain and Exposure of Meteorological Monitoring Site*: Both the project and the meteorological station are located on the southern bank of the San Joaquin River and are the same distances from prominent terrain features in the surrounding area.
>
> *Period of Data Collection*: The 2000 through 2002 and 2004 through 2005 data set represents data collection over five years. Although only one year of onsite data is required, a five-year data set was used to better represent project site conditions, as well as to capture worst-case meteorological conditions.
>
> *Data Quality:* The PG&E meteorological station was audited regularly to ensure quality data were collected.

Onsite hourly data include wind speed, wind direction, standard deviation of the horizontal wind, and temperature for years 2000 through 2002 and 2004 through 2005.

In processing the data for input into AERMOD, additional parameters typically not collected at site specific stations are required; thus, the site specific data are supplemented with data from the nearest National Weather Service (NWS) station. Surface data were obtained from the Concord Buchanan Field Airport for the same years as the onsite data: 2000 through 2002 and 2004 through 2005. This station is approximately 25 kilometers (16 miles) west of the project and is surrounded by suburban areas, in rolling terrain. The terrain immediately surrounding the project site can be categorized as suburban with rolling hills; thus the land use and the location with respect to near-field terrain features are similar. Cloud cover information from Concord Buchanan Field Airport data was used; however, Concord surface winds were not substituted for missing hours in the CCPP onsite meteorological data sets.

The Oakland Airport upper air data monitoring station is located approximately 52 kilometers (32 miles) southwest of the project. This is the closest upper air station and was determined to be the most representative data available for use in this modeling analysis. The MODIFY option was used for Oakland upper air data AERMET processing in order to perform some preliminary quality control as the data were extracted.

Representative surface moisture input was determined for each month of every year using Antioch Pump Plant 3 meteorological station precipitation data and the percentile method specified in the AERSURFACE User's Guide. The surface moisture determinations are provided by BAAQMD in Table 7-1. Months assigned to each season were as follows: Spring—February and March; Summer—April through July; Fall—August through October; Winter—November through January and not receiving continuous snow cover. Finally, the seasonal output obtained for the surface characteristics for all sectors, dependent on average, wet, or dry surface moisture conditions, are presented in Table 7-2. These are the surface characteristics that were used for input into AERMET. Figure 7-1 presents the annual wind rose based on the 2000-2002 and 2004-2005 CCPP onsite meteorological data.

Receptor Locations

The receptor grids used in the AERMOD modeling analyses described in this protocol for operational sources were as follows:

- 25-meter spacing along the MLGS fence line and extending from the fence line out to 100 meters beyond the CCPP property line;
- 100-meter spacing from 100 m to 1 km beyond the property line;
- 500-meter spacing within 1 to 5 km of property line; and
- 1,000-meter spacing within 5 to 10 km of property line.

Figures 7.-2 and 7.-3 show the placement of near-field and far-field receptor points, respectively. Within the 1,000-meter spacing 5- to 10-km from the property line, it was determined that a tighter 250-meter spaced receptor grid would best cover a hill southwest of the project. Terrain heights at receptor grid points were determined from USGS digital elevation model (DEM) files. In the course of the refined modeling analysis to evaluate operational project emissions, if a maximum predicted concentration for a particular pollutant and averaging time was located within a portion of the receptor grid with spacing greater than 25 meters, a supplemental dense receptor grid was placed around the original maximum concentration point and the model was rerun. The dense grid used 25-m spacing and extended to the next grid point in all directions from the original point of maximum concentration. Terrain heights specifically corresponding to the supplementary grid points will be determined from the USGS DEM files in the same manner as for the original receptors.

Due to the large computational time required to run AERMOD for multiple sources and 5 years of hourly meteorological input data, this receptor grid, with the additional dense nested grid points, was determined to best balance the need to predict maximum pollutant concentrations and allow all operational modeling runs to be completed within a reasonable period of time.

Construction Impacts

For purposes of evaluating construction air quality impacts, it is useful to break the construction schedule into a sequence of essentially non-overlapping phases, each occurring on specific areas of the proposed project site and with characteristic equipment and vehicle requirements.

The equipment point source emissions were calculated by means of the emission spreadsheet in Appendix C and stack parameters for different-sized (horsepower) equipment. These stack parameters were obtained from the CARB document *Risk Management Guidance for the Permitting of New Stationary Source Diesel-Fueled Engines* (2000).

Detailed spreadsheets are provided in Appendix C; these show the calculations of emissions from all project construction activities and equipment, and the data of assumptions used in these calculations. Table 7.-3 presents the estimated maximum monthly emissions and maximum annual emissions of air pollutants due to project construction.Calculation of annual emissions was based on a summation over all construction activities for the consecutive 12-month period that would produce the highest emissions of all pollutants.

Turbine Impact Screening Modeling

As described previously, a screening modeling analysis was performed to determine which CTG operating modes and stack parameters produced the worst-case offsite impacts (i.e., maximum ground-level concentrations for each pollutant and averaging time). Screening modeling was performed for both the (1) FP10 CTG stack scenario and (2) the Simple Cycle CTG stack scenario. Only the emissions from the CTGs were considered in this preliminary modeling step. The screening model was accomplished with AERMOD, as described in the previous sections. Building wake information and the receptor grid described above were also used. All five years of meteorological data were used in the screening analysis.

The AERMOD model simulated natural gas CTG emissions from:

- The 21.3-foot-diameter (6.5-m), 150.5-foot-tall (45.9-m) stack; representative of the FP10 Combined Cycle CTG stack scenario; and
- The 31.3-foot-diameter (9.5-m), 150.3-foot-tall (45.8-m) stack; representative of the Simple Cycle CTG stack scenario.

The stacks were modeled as point sources at their proposed locations within the project site. Tables 7.-4 and 7.-5 summarize the CTG screening results for both scenarios (combined cycle and simple cycle) under the different CTG operating loads and ambient temperature conditions. First, the model was run with unit emissions (1.0 grams per second) from each stack to obtain normalized concentrations that are not specific to any pollutant. CTG vendor data used to derive the stack parameters for the different operating conditions evaluated in this screening analysis are included in Appendix C.

The maximum ground-level concentrations predicted to occur offsite with the unit turbine emission rates for each of the 12 operating conditions shown in Tables 7.-4 and 7.-5 were then multiplied by the corresponding turbine emission rates for specific pollutants. The highest resulting concentration values for each pollutant and averaging time were then identified (see bolded values in the table).

The stack parameters associated with these maximum predicted impacts were used in all subsequent simulations of the refined AERMOD analyses described in the next subsection. Note that the lower exhaust temperatures and flow rates at reduced turbine loads correspond to reduced plume rise, in some cases resulting in higher offsite pollutant concentrations than the higher base load emissions. Model input and output files for the screening modeling analysis are included in a DVD accompanying this application package.

1-Hour Startup Scenarios

The worst-case one-hour NO_2 and CO impacts would occur during an hour with one startup; thus, the results of the screening analysis were not used to determine the turbine stack parameters. The results provided in Table 7-6 indicate that maximum hourly NO_2 and CO concentrations during normal operations for both the FP10s and the Simple Cycle turbines would occur with the stack parameters corresponding to full-load operations. However the magnitude of the emissions for both these pollutants during the worst-case 60 minutes of a four-turbine startup sequence would be higher than those during normal operations at any ambient temperature condition. Since a startup is a transition from non-operation to full-load operation, the stack exhaust velocity and temperature during most of this operation are lower than the values indicated as "worst-case" by the turbine screening modeling. Accordingly, modeling simulations were conducted to estimate the maximum one-hour NO_2 and CO concentrations during a startup with reduced stack exhaust velocity and temperature.

Refined Modeling

A refined modeling analysis was performed to estimate offsite criteria pollutant impacts from operational emissions of the proposed project. The modeling was performed as described in the previous sections, using 5 years of hourly meteorological input data. The new project FP10 units were modeled assuming the worst-case emissions corresponding to each averaging time and the turbine stack parameters that were determined in the turbine screening analysis (see above). The maximum mass emission rates that would occur over any averaging time, whether during turbine startups, normal operations, turbine shutdowns, or a combination of these activities, were used in all refined modeling analyses (see Table 7-7). Emission rate calculations and assumptions used for all pollutants and averaging times are documented in Appendix C.

Fumigation Analysis

Fumigation may occur when a plume that was originally emitted into a stable layer of air is mixed rapidly to ground level when unstable air below the plume reaches plume height. Fumigation can cause relatively high ground-level concentrations for some elevated point sources during either the breakup of the nocturnal radiation inversion by solar warming of the ground surface (inversion breakup fumigation), or by the transport of pollutants from a stable marine environment to an unstable onshore environment (shoreline fumigation). The transition from stable to unstable surroundings can rapidly draw a plume down to ground level and create relatively high pollutant concentrations for a short period. In general, this phenomenon will be transient, seldom persisting for as long as an hour. Typically, a fumigation analysis is conducted using SCREEN3 when the project site is rural and the stack height is greater than 10 meters.

The SCREEN3 model was used to calculate concentrations from both inversion breakup fumigation and shoreline fumigation. A unit emission rate was used (1 gram per second) in the fumigation modeling to represent the project emissions and the model results were scaled to reflect expected plant emissions for each pollutant. Since SCREEN3 only models the impacts from one source, the model was run three times, once for the FP10 combined cycle stack parameters, once for simple cycle stack parameters and once for the fuel gas heater stack parameters. To calculate the inversion breakup fumigation, the default thermal internal boundary layer (TIBL) factor of 6 in the SCREEN3 model was used. For shoreline fumigation, a range of TIBL factors, 2, 4, and 6, were used to determine the highest impact. BAAQMD provided a modified version of SCREEN3 that allows the input of various TIBL factors.

For both the nocturnal inversion and shoreline inversion analyses, impacts were determined for each source, then summed over all sources using peak predicted fumigation and non-fumigation concentrations regardless of location. Since fumigation impacts can affect concentrations longer than 1 hour, the procedures described in Section 4.5.3 of "Screening Procedures for Estimating the Air Quality Impact of Stationary Sources" (U.S. EPA, 1992a) were used to determine the 3-, 8- and 24-hour average concentrations.

SCREEN3 predicted the peak concentration from nocturnal inversion fumigation from project emissions to be 15.6 $\mu g/m^3$ for NO_2 1-hour, 2.4 $\mu g/m^3$ for SO_2 1-hour, 2.0 $\mu g/m^3$ for SO_2 3-hour, 0.8 $\mu g/m^3$ for SO_2 24-hour, 78.5 $\mu g/m^3$ for CO 1-hour, 22.9 $\mu g/m^3$ for CO 8-hour, and 1.2 $\mu g/m^3$ for $PM_{10}/PM_{2.5}$ 24-hour averaging periods. The peak concentration from the shoreline inversion fumigation analysis from project emissions was predicted to be 66.8 $\mu g/m^3$ for NO_2 1-hour, 11.9 $\mu g/m^3$ for SO_2 1-hour, 6.3 $\mu g/m^3$ for SO_2 3-hour, 1.0 $\mu g/m^3$ for SO_2 24-hour, 454.0 $\mu g/m^3$ for CO 1-hour, 43.2 $\mu g/m^3$ for CO 8-hour, and 1.5 $\mu g/m^3$ for $PM_{10}/PM_{2.5}$ 24-hour averaging periods.

7.2 *Compliance with Ambient Air Quality Standards and PSD Requirements*

Air dispersion modeling was performed according to the methodology described in Section 7.1 to evaluate the maximum increase in ground-level pollutant concentrations resulting from project emissions, and to compare the maximum predicted impacts, including background pollutant levels, with applicable short-term and long-term CAAQS and NAAQS. The same 5-year record of hourly meteorological data was used in the AERMOD modeling to evaluate the operational impacts.

In evaluating the operational impacts, the AERMOD model was used to predict the increases in criteria pollutant concentrations at all receptor concentrations due to project emissions only. Next, the maximum modeled incremental increases for each pollutant and averaging time were added to the maximum background concentrations, based on air quality data collected at the most representative monitoring stations during the last 3 years (i.e., 2004 through 2006). The resulting total pollutant concentrations were then compared with the most stringent CAAQS or NAAQS.

7.2.1 Normal Plant Operation

As described previously, the emissions used in the AERMOD simulations for the project operations were selected to ensure that the maximum potential impacts would be addressed for each pollutant and averaging time corresponding to an ambient air quality standard. The emissions used for each pollutant and averaging time are explained and quantified in Table 7-8. This subsection describes the maximum predicted operational impacts of the project for normal FP10 combined-cycle operating conditions. Commissioning impacts, which would occur on a temporary, one-time basis and would not be representative of normal operations, were addressed separately, as described below under Turbine Commissioning.

Table 7-9 summarizes the maximum predicted criteria pollutant concentrations due to the operational FP10 combined-cycle plant. The incremental impacts of project emissions would be below the federal PSD significant impact levels (SILs) for all attainment pollutants, despite the use of worst-case emissions scenarios for all pollutants and averaging times. Although maximum predicted values for PM_{10} are below the SILs, these thresholds do not apply to this pollutant because the Basin is designated nonattainment with respect to the federal ambient standards. No SILs have been established yet for $PM_{2.5}$.

Table 7-9 also shows that the modeled impacts due to the project emissions, in combination with conservative background concentrations, would not cause a violation of any NAAQS and would not significantly contribute to the existing violations of the federal and state PM_{10} and $PM_{2.5}$ standards. In addition, as described later, all of the proposed project's operational emissions of nonattainment pollutants and their precursors will be offset to ensure a net air quality benefit.

The locations of predicted maximum impacts would vary by pollutant and averaging time. Peak annual average concentrations for all pollutant would be within approximately 1,000 feet to the east of the facility fenceline. The 1-hour maxima for NO_2, SO_2, and CO and 24-hour PM_{10} are predicted to occur in the elevated terrain approximately 5 miles southwest of the facility. The highest 3-hour and 24-hour SO_2, and the highest 8-hour CO concentrations are expected to occur a few hundred feet north of the plant site. Figure 7-4 shows the locations of the maximum predicted operational impacts for all pollutants and averaging times.

7.2.2 Turbine Commissioning

Each of the project CTGs could be operated for up to 500 hours with partially abated emissions for purposes of commissioning the new generating equipment. Separate modeling was conducted using AERMOD to evaluate maximum short-term effects of these activities in terms of the impacts on offsite 1-hour NO_2 concentrations and 1-hour and 8-hour CO concentrations. These are the pollutants (along VOCs, which are not modeled) for which emissions would be expected to be significantly higher than during normal operations, owing to the nonoperability of the SCR and oxidation catalyst emission control systems during some of the commissioning tests. Emissions of SO_X and particulate matter (PM) depend primarily on the rate of fuel combustion and are unaffected by the availability or nonavailability of the SCR and oxidation catalyst. Thus, emissions of these pollutants during commissioning are not expected to exceed the levels that would occur during full-load normal operations of the turbines, and separate modeling for commissioning impacts on SO_X and PM levels is unnecessary.

Stack NO_X and CO emission rates were presented in Table 7-10 and Table 7-11. Modeling was conducted for the tests that were expected to produce the highest offsite concentrations at ground level, i.e., the test with the highest emission rate in combination with the lowest exhaust flow and temperature. For the NO_X modeling, the emissions for the row labeled "CTG 1 Testing at 40% load" in Table 7-10 and Table 7-11 were used. Maximum CO impacts were evaluated for the case labeled "CTG Testing (Full Speed No Load, FSNL, Excitation Test, Dummy Synch Checks)." Startup stack parameters were used.

Table 7-12 shows the results of the model simulations for turbine commissioning. The tabulated impacts are the highest concentrations for the indicated averaging that are predicted by AERMOD to occur using 5 years of hourly meteorological input data. The modeling was conducted for commissioning of both simple-cycle turbines concurrently under worst-case emission conditions and then for commissioning of both FP10 turbines concurrently under worst-case emission conditions with the Simple Cycle turbines operating at startup conditions. Table 7-12 demonstrates that when the maximum incremental commissioning impacts are added to applicable background concentrations and compared with the most stringent state or national ambient standards, no violations of the applicable standards for these pollutants are predicted to occur.

7.2.3 Impacts for Non-attainment Pollutants and their Precursors

The emission offset program described in the BAAQMD Rules and Regulations was developed to facilitate net air quality improvement when new sources locate within the BAAQMD. Project impacts of nonattainment pollutants ($PM_{10,}$ $PM_{2.5}$, and O_3) and their precursors (NO_X, SO_2, and VOC) will be fully mitigated by emission offsets. The emission reductions associated with these offsets have not been accounted for in the modeled impacts noted above. Thus, the impacts indicated in the foregoing presentation of model results for the proposed project may be significantly overestimated.

7.2.4 Impacts on Air Quality Related Values in Class I Area

U.S. EPA has promulgated PSD regulations applicable to Major Sources and Major Modifications, as these terms are defined in 40 CFR 51.166. The proposed project would be a New Major Source because of the increases that would result in CO, PM_{10} and NO_X emissions. Many of the PSD requirements are the same as those that must be met for compliance with the BAAQMD's New Source Review rule (Regulation II, Rule 2) and CEC's guidance for air quality impact evaluations (e.g., quantification of project emissions, demonstration of BACT, AAQS analysis). However, PSD requires the following additional analyses:

- An analysis of the potential incremental impacts from the new emissions from the proposed project relative to PSD SILs, and if necessary with the PSD increments.
- An analysis of AQRVs to ensure the protection of visibility in federal Class I National Parks and National Wilderness Areas within 100 km (62 miles) of the proposed project site;
- An evaluation of potential impacts on soils and vegetation of commercial and recreational value; and
- An evaluation of potential growth-inducing impacts.

Effects on Visibility from Plumes

Modern combined-cycle power plants burning natural gas fuel emit PM at levels far below the concentration corresponding to visible smoke. Combustion sources also emit water vapor that sometimes may condense in the atmosphere to form visible plumes. However, the generally warm, dry conditions in Contra Costa County are not conducive to lengthy visible stack plumes, and the historical operation of the existing CCPP Units 5 and 6 indicates that moisture plumes rarely extend to appreciable distances. Evaporative cooling towers are another potentially more important source of visible moisture plumes at power plants, but the proposed project will employ air-cooled condensers that do not produce moisture plumes.

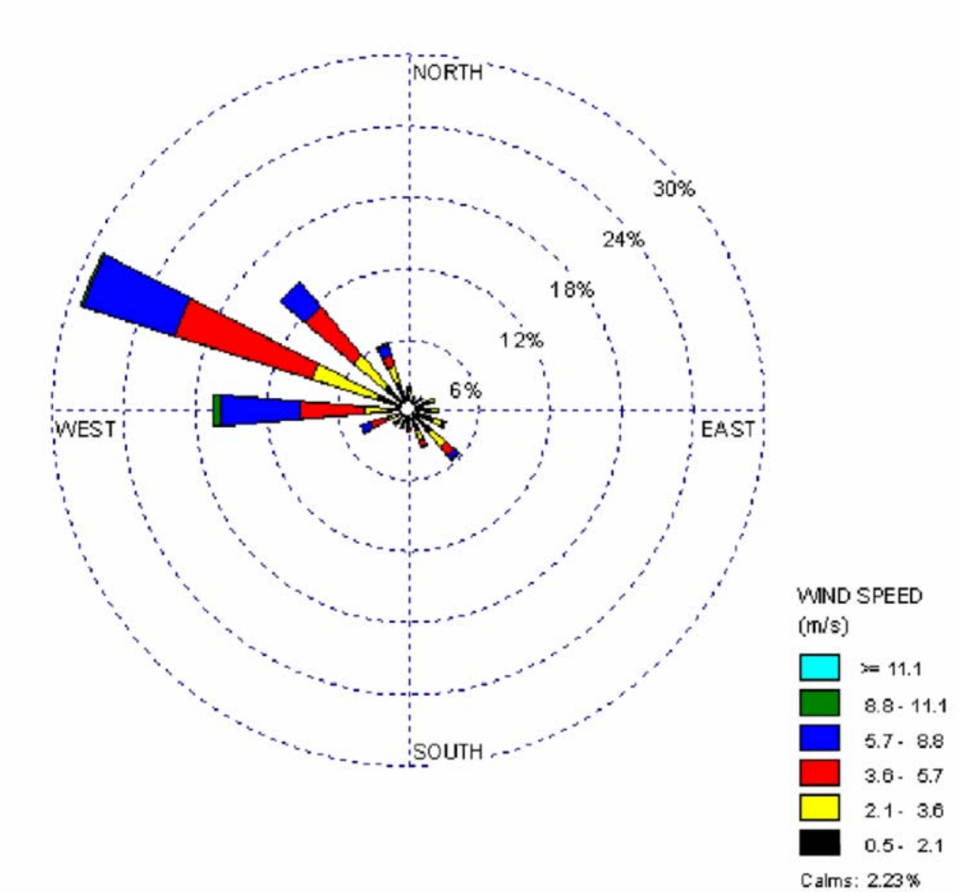
The Simple Cycle units will have exhaust gas temperatures exiting the stack above 700ºF for all operating loads. No visible plumes will occur from these units.

Impacts in Class II PSD Areas

As the proposed project would trigger PSD as a New Major Source, modeling is required to determine whether its incremental impacts on ambient levels of attainment pollutants (NO_2, SO_2, and CO) would exceed Class II SILs. The SILs for PM_{10} and $PM_{2.5}$ are not applicable because of the state nonattainment status of the San Francisco Bay Air Basin for this pollutant. If project emissions were predicted to cause the SILs for attainment pollutants to be exceeded, then an analysis of total increment consumption since the local PSD baseline date would be required. However, as demonstrated by Table 7-9, the maximum modeled incremental pollutant concentrations for all attainment pollutants are below the Class II SILs; thus, no further analysis of impacts in PSD Class II areas is required.

Impacts in Class I PSD areas

An evaluation of impacts in Class I areas within 100 km (62 miles) of the proposed project is typically conducted when the potential emissions increases from the project would be sufficient to trigger federal PSD requirements. The Applicant contacted the National Park Service administrator for Point Reyes National Seashore, the only Class I area located within 100 km of the proposed project. The National Park Service determined a Class I impact analysis is not required for this project.



Annual windrose for Contra Costa Power Plant onsite meteorological station
Data taken from 2000-2002 and 2004-2005 for all months.

Displays wind speed, direction (blowing from)

ANNUAL WIND ROSE FOR 2000-2002 AND 2004-2005

Marsh Landing Generating Station
Mirant Marsh Landing, LLC
Contra Costa County, California

June 2008
28067344

URS

FIGURE 7-1

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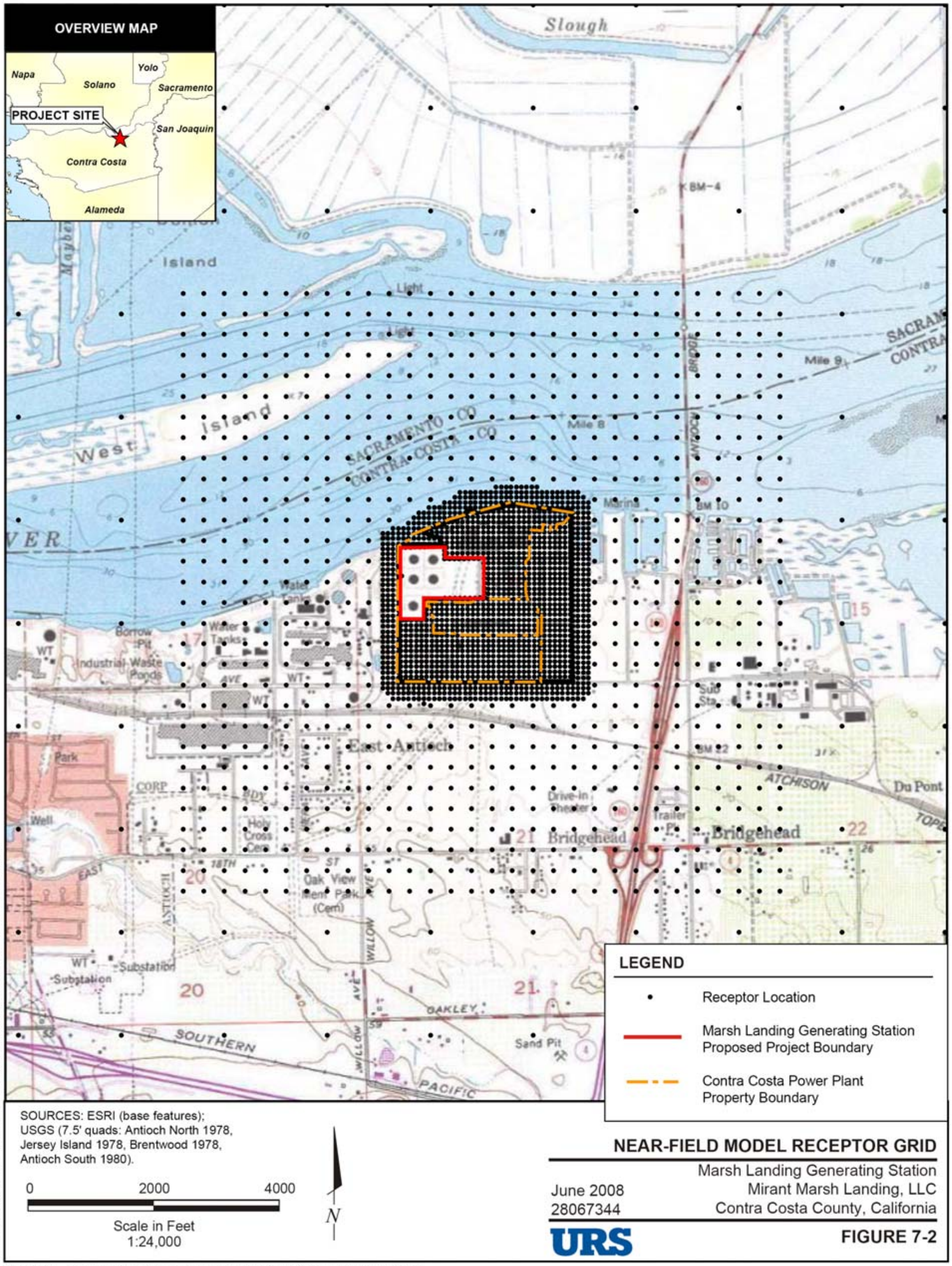

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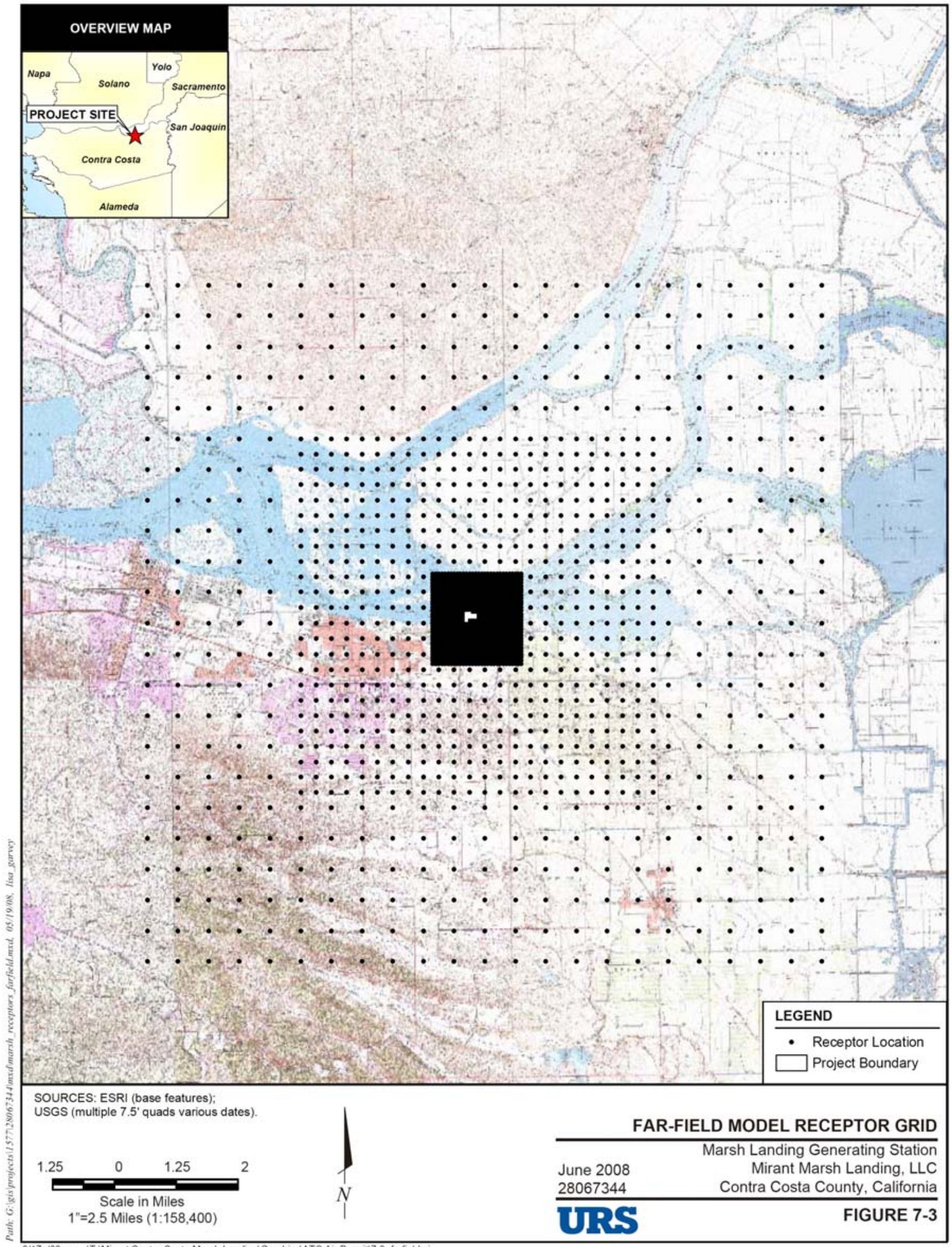

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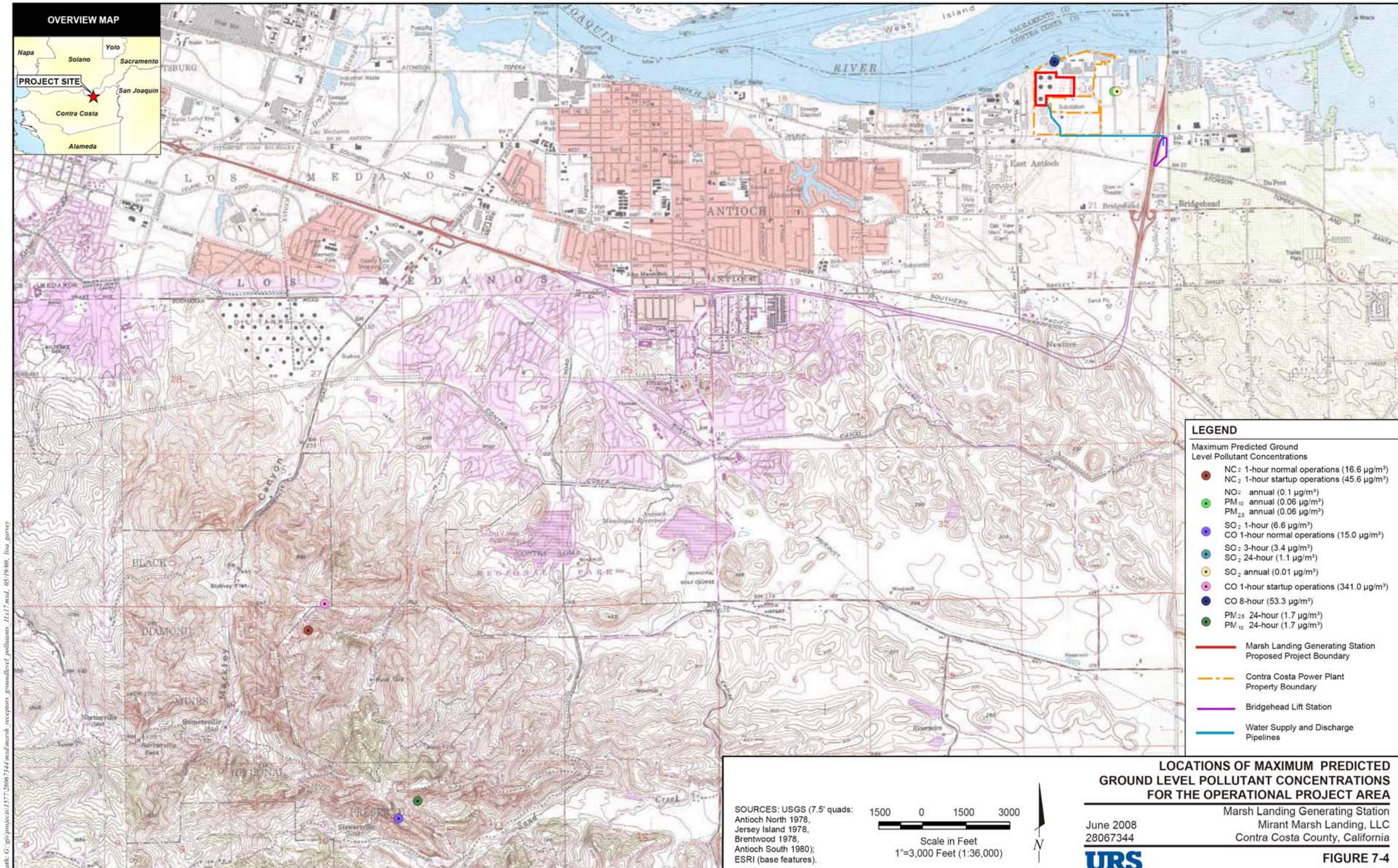

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Table 7-1 Surface Moisture Conditions at the Antioch Pump Plant 3 Station for Years 2000-2002, 2004-2005

Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2000	wet	wet	dry	wet	wet	avg	dry	dry	avg	wet	avg	dry
2001	avg	wet	dry	avg	avg	wet	dry	wet	dry	dry	avg	wet
2002	dry	dry	avg	dry	dry	dry	dry	dry	dry	dry	avg	wet
2004	avg	wet	dry	dry	avg	dry	dry	dry	dry	wet	avg	wet
2005	wet	avg	wet	avg	avg	wet	dry	dry	dry	dry	dry	wet

Note:
Surface moisture conditions provided by BAAQMD.

Table 7-2 Land Use Characteristics Used in AERMET

Month	Sector	Range	Land Use Characteristics				
			Albedo (α)	Bowen Ratio (β) Avg. sfc moisture	Bowen Ratio (β) Dry sfc moisture	Bowen Ratio (β) Wet sfc moisture	Surface Roughness (Z_o) (m)
Jan	1	62°-150°	0.16	0.49	0.93	0.33	0.41
Jan	2	150°-182°	0.16	0.49	0.93	0.33	0.483
Jan	3	182°-243°	0.16	0.49	0.93	0.33	0.442
Jan	4	243°-274°	0.16	0.49	0.93	0.33	0.529
Jan	5	274°-62°	0.16	0.49	0.93	0.33	0.02
Feb	1	62°-150°	0.15	0.34	0.69	0.27	0.469
Feb	2	150°-182°	0.15	0.34	0.69	0.27	0.518
Feb	3	182°-243°	0.15	0.34	0.69	0.27	0.498
Feb	4	243°-274°	0.15	0.34	0.69	0.27	0.536
Feb	5	274°-62°	0.15	0.34	0.69	0.27	0.021
Mar	1	62°-150°	0.15	0.34	0.69	0.27	0.469
Mar	2	150°-182°	0.15	0.34	0.69	0.27	0.518
Mar	3	182°-243°	0.15	0.34	0.69	0.27	0.498
Mar	4	243°-274°	0.15	0.34	0.69	0.27	0.536
Mar	5	274°-62°	0.15	0.34	0.69	0.27	0.021
Apr	1	62°-150°	0.16	0.41	0.83	0.3	0.523
Apr	2	150°-182°	0.16	0.41	0.83	0.3	0.546
Apr	3	182°-243°	0.16	0.41	0.83	0.3	0.544
Apr	4	243°-274°	0.16	0.41	0.83	0.3	0.542
Apr	5	274°-62°	0.16	0.41	0.83	0.3	0.021
May	1	62°-150°	0.16	0.41	0.83	0.3	0.523
May	2	150°-182°	0.16	0.41	0.83	0.3	0.546
May	3	182°-243°	0.16	0.41	0.83	0.3	0.544
May	4	243°-274°	0.16	0.41	0.83	0.3	0.542
May	5	274°-62°	0.16	0.41	0.83	0.3	0.021
Jun	1	62°-150°	0.16	0.41	0.83	0.3	0.523
Jun	2	150°-182°	0.16	0.41	0.83	0.3	0.546
Jun	3	182°-243°	0.16	0.41	0.83	0.3	0.544
Jun	4	243°-274°	0.16	0.41	0.83	0.3	0.542
Jun	5	274°-62°	0.16	0.41	0.83	0.3	0.021
Jul	1	62°-150°	0.16	0.41	0.83	0.3	0.523

Table 7-2
Land Use Characteristics used in AERMET (Continued)

Month	Sector	Range	Land Use Characteristics				
			Albedo (α)	Bowen Ratio (β) Avg. sfc moisture	Bowen Ratio (β) Dry sfc moisture	Bowen Ratio (β) Wet sfc moisture	Surface Roughness (Z_o) (m)
Jul	2	150°-182°	0.16	0.41	0.83	0.3	0.546
Jul	3	182°-243°	0.16	0.41	0.83	0.3	0.544
Jul	4	243°-274°	0.16	0.41	0.83	0.3	0.542
Jul	5	274°-62°	0.16	0.41	0.83	0.3	0.021
Aug	1	62°-150°	0.16	0.49	0.93	0.33	0.523
Aug	2	150°-182°	0.16	0.49	0.93	0.33	0.546
Aug	3	182°-243°	0.16	0.49	0.93	0.33	0.544
Aug	4	243°-274°	0.16	0.49	0.93	0.33	0.542
Aug	5	274°-62°	0.16	0.49	0.93	0.33	0.021
Sep	1	62°-150°	0.16	0.49	0.93	0.33	0.523
Sep	2	150°-182°	0.16	0.49	0.93	0.33	0.546
Sep	3	182°-243°	0.16	0.49	0.93	0.33	0.544
Sep	4	243°-274°	0.16	0.49	0.93	0.33	0.542
Sep	5	274°-62°	0.16	0.49	0.93	0.33	0.021
Oct	1	62°-150°	0.16	0.49	0.93	0.33	0.523
Oct	2	150°-182°	0.16	0.49	0.93	0.33	0.546
Oct	3	182°-243°	0.16	0.49	0.93	0.33	0.544
Oct	4	243°-274°	0.16	0.49	0.93	0.33	0.542
Oct	5	274°-62°	0.16	0.49	0.93	0.33	0.021
Nov	1	62°-150°	0.16	0.49	0.93	0.33	0.41
Nov	2	150°-182°	0.16	0.49	0.93	0.33	0.483
Nov	3	182°-243°	0.16	0.49	0.93	0.33	0.442
Nov	4	243°-274°	0.16	0.49	0.93	0.33	0.529
Nov	5	274°-62°	0.16	0.49	0.93	0.33	0.02
Dec	1	62°-150°	0.16	0.49	0.93	0.33	0.41
Dec	2	150°-182°	0.16	0.49	0.93	0.33	0.483
Dec	3	182°-243°	0.16	0.49	0.93	0.33	0.442
Dec	4	243°-274°	0.16	0.49	0.93	0.33	0.529
Dec	5	274°-62°	0.16	0.49	0.93	0.33	0.02

Table 7-3 Maximum Monthly and 12-Month Total Construction Emissions

	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_X	VOC
Construction Emissions						
Monthly Emissions (tons)	11.23	3.69	0.16	0.15	0.0043	0.69
12-Month (tons)	85.02	28.7	1.25	1.14	0.034	5.33
Onsite Fugitive Dust Emissions						
Yearly Emissions (tons)	0	0	1.70	0.35	0	0

Notes:

CO = carbon monoxide
CO_2 = carbon dioxide
CH_4 = methane
N_2O = nitrous oxide
N/A = not applicable
$PM_{2.5}$ = particulate matter less than or equal to 2.5 microns in diameter
PM_{10} = particulate matter less than or equal to 10 microns in diameter
VOC = volatile organic compounds
SO_x = sulfur oxides

Table 7-4 Marsh Landing Turbine Screening Results FP10 Combined-Cycle Units

Normal Operations – New Siemens Peaker Flex-Plant 10 Emissions and stack parameters per Turbine												
Case	**Case 1A**	**Case 1B**	**Case 1C**	**Case 2A**	**Case 2B**	**Case 2C**	**Case 3A**	**Case 3B**	**Case 3C**	**Case 3D**	**Case 3E**	**Case 3F**
Ambient Temperature	Winter Minimum: 20°F			Yearly Average: 59°F			Summer Maximum: 94°F					
CTG Load Level	**100%**	**85%**	**60%**	**100%**	**85%**	**60%**	**100%**	**100%**	**100%**	**100%**	**85%**	**60%**
Evaporative Cooler Status/Effectiveness	OFF	OFF	OFF	OFF	OFF	OFF	ON	ON	OFF	OFF	OFF	OFF
Power Augmentation Status	OFF	OFF	OFF	OFF	OFF	OFF	ON	OFF	ON	OFF	OFF	OFF
Stack Outlet Temperature (°F)	350.0	346.0	343.7	340.0	337.0	328.7	338.0	348.0	333.0	341.0	346.0	323.3
Stack Outlet Temperature (°K)	449.82	447.59	446.32	444.26	442.59	437.98	443.15	448.71	440.37	444.82	447.59	434.98
Stack Exit Velocity (ft/s)	70.5	61.5	50.1	64.3	57.0	44.9	65.2	62.5	61.6	59.0	53.4	42.8
Stack Exit Velocity (m/s)	21.488	18.745	15.270	19.599	17.374	13.694	19.873	19.050	18.776	17.983	16.276	13.054
NO_X as NO_2 (at 2.0 ppm) (lb/hr)	17.4	15.1	12.0	15.8	13.9	10.0	16.3	15.2	15.3	14.3	12.9	10.0
CO (at 3.0 ppm) (lb/hr)	15.9	13.8	10.7	14.6	12.8	9.5	15.0	14.0	14.1	13.1	11.7	9.0
SO_2 (lb/hr) (based on 0.4 gr total S/100 scf)	2.6	2.3	1.8	2.3	2.1	1.6	2.4	2.2	2.3	2.1	1.9	1.5
SO_2 (lb/hr) (based on 1.0 gr total S/100 scf)	6.4	5.6	4.5	5.8	5.2	4.0	6.0	5.6	5.6	5.3	4.7	3.8
PM_{10} (lb/hr)	10.0	8.9	8.0	9.3	8.3	8.0	8.9	8.8	8.5	8.5	7.7	8.0
NO_X (g/s)	2.194	1.904	1.513	1.993	1.753	1.261	2.056	1.917	1.930	1.803	1.627	1.261
CO (g/s)	2.005	1.740	1.343	1.835	1.608	1.192	1.892	1.759	1.778	1.646	1.481	1.135
SO_2 (g/s) (based on 0.4 gr total S/100 scf)	0.324	0.284	0.226	0.294	0.260	0.201	0.303	0.283	0.285	0.266	0.239	0.191
SO_2 (g/s) (based on 1.0 gr total S/100 scf)	0.811	0.710	0.565	0.736	0.650	0.501	0.758	0.707	0.712	0.664	0.598	0.477
PM_{10} (g/s)	1.261	1.122	1.009	1.173	1.047	1.009	1.122	1.110	1.072	1.072	0.965	1.009
Model Results – Maximum X/Q concentration ($\mu g/m^3/(g/s)$) predicted from AERMOD (all receptors)												
1–hour	5.55965	6.39021	7.33176	6.21427	6.88479	7.66238	6.15996	6.27236	6.54808	6.67282	7.07871	8.00202
3–hour	2.52533	2.62658	2.79198	2.60721	2.68459	3.12694	2.60129	2.61327	2.64530	2.66044	2.70648	3.27204
8–hour	1.79462	2.02509	2.36680	1.96750	2.18828	2.52911	1.95020	1.98885	2.07011	2.11589	2.26384	2.57534
24–hour	0.68286	0.78855	0.91603	0.76601	0.85165	0.96573	0.75916	0.77407	0.80698	0.82415	0.87921	0.97548
annual	0.06662	0.07814	0.09798	0.07541	0.08658	0.11383	0.07461	0.07644	0.08031	0.08268	0.09104	0.12129
Maximum Concentration ($\mu g/m^3$) Predicted per Pollutant Normal Operations (all receptors)												
NO_X 1 hour	12.19973	12.16873	11.09540	12.38228	12.06865	9.66311	**12.66248**	12.02342	12.63452	12.03369	11.51588	10.09144
annual	0.14619	0.14880	0.14828	0.15026	0.15177	0.14355	0.15337	0.14653	**0.15496**	0.14910	0.14811	0.15296
CO 1 hour	11.14802	11.12110	9.84716	11.40267	11.07017	9.13164	**11.65259**	11.03465	11.64358	10.98179	10.48481	9.08229
8 hour	3.59851	3.52433	3.17881	3.61020	3.51857	3.01407	**3.68913**	3.49888	3.68100	3.48223	3.35314	2.92301
SO_2 1 hour	4.50825	4.53423	4.14568	4.57522	4.47739	3.84191	**4.66830**	4.43377	4.66294	4.43394	4.23328	3.81297
3 hour	**2.04776**	1.86371	1.57870	1.91954	1.74587	1.56785	1.97138	1.84725	1.88374	1.76780	1.61856	1.55913
24 hour	0.55372	0.55952	0.51796	0.56397	0.55385	0.48422	**0.57533**	0.54717	0.57466	0.54763	0.52579	0.46482
annual	0.02161	0.02218	0.02216	0.02221	0.02252	0.02283	0.02262	0.02161	0.02288	0.02198	0.02178	**0.02312**
PM_{10} 24 hour	0.86116	0.88506	0.92417	0.89840	0.89144	0.97431	0.85207	0.85905	0.86504	0.88344	0.84822	**0.98415**
annual	0.08402	0.08770	0.09885	0.08844	0.09063	0.11484	0.08374	0.08483	0.08609	0.08863	0.08783	**0.12237**
	Case 1A	**Case 1B**	**Case 1C**	**Case 2A**	**Case 2B**	**Case 2C**	**Case 3A**	**Case 3B**	**Case 3C**	**Case 3D**	**Case 3E**	**Case 3F**

Table 7-5 Marsh Landing Turbine Screening Results Simple Cycle Units

Normal Operations – New Siemens SSC6-5000F Simple Cycle Gas Turbines										
Case		**Case A1**	**Case A2**	**Case A3**	**Case B1**	**Case B2**	**Case B3**	**Case C1**	**Case C2**	**Case C3**
Ambient Temperature		Winter Minimum: 20°F/90% RH			Yearly Average: 60°F/64% RH			Summer Maximum: 94°F		
CTG Load Level		100%	75%	60%	100%	75%	60%	100%	75%	60%
Evaporative Cooler Status/Effectiveness		OFF	OFF	OFF	ON	OFF	OFF	ON	OFF	OFF
Gas Turbine Outlet Temperature (ºF)		1,065	1,065	1,065	1,090	1,090	1,091	1,123	1,123	1,122
Stack Outlet Temperature (°F)		750	750	750	750	750	750	750	750	750
Stack Outlet Temperature (°K)		672.04	672.04	672.04	672.04	672.04	672.04	672.04	672.04	672.04
Stack Exit Velocity (ft/s)		70.9	57.6	50.8	68.3	56.6	37.2	65.9	55.4	49.1
Stack Exit Velocity (m/s)		21.600	17.544	15.498	20.814	17.256	11.347	20.086	16.900	14.965
NO_X as NO_2 (at 2.5 ppm)		20.83	16.39	13.89	18.89	15.00	12.78	16.94	13.89	11.67
CO (at 3.0 ppm)		15.00	12.00	10.20	13.50	11.25	9.30	12.75	9.75	8.70
SO_2 (lb/hr) (based on 0.4 gr total S/100 scf)		2.48	1.96	1.67	2.25	1.80	1.54	2.03	1.65	1.41
SO_2 (lb/hr) (based on 1.0 gr total S/100 scf)		6.21	4.90	4.17	5.63	4.51	3.84	5.08	4.11	3.52
PM_{10} (lb/hr)		9.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
NO_X (g/s)		2.627	2.067	1.752	2.382	1.892	1.611	2.137	1.752	1.471
CO (g/s)		1.892	1.513	1.286	1.703	1.419	1.173	1.608	1.230	1.097
SO_2 (g/s) (based on 0.4 gr total S/100 scf)		0.313	0.247	0.210	0.284	0.227	0.194	0.256	0.208	0.178
SO_2 (g/s) (based on 1.0 gr total S/100 scf)		0.783	0.617	0.526	0.710	0.569	0.485	0.641	0.519	0.444
PM_{10} (g/s)		1.135	1.009	1.009	1.009	1.009	1.009	1.009	1.009	1.009
Model Results – Maximum X/Q concentration ($\mu g/m^3/(g/s)$) predicted from AERMOD (all receptors)										
1-hour		3.81519	4.29956	4.52619	3.90087	4.32415	5.53626	3.98518	4.34822	4.6149
3-hour		2.56074	3.18069	3.59731	2.66051	3.24175	4.40488	2.73866	3.31427	3.66946
8-hour		1.96712	2.4339	2.71571	2.00873	2.47382	3.49552	2.05926	2.52664	2.78208
24-hour		0.65725	0.90202	1.00427	0.67116	0.91683	1.46597	0.75893	0.93587	1.02869
annual		0.01714	0.02108	0.02459	0.01754	0.02151	0.03774	0.01794	0.02208	0.02575
Maximum Concentration ($\mu g/m^3$) predicted per Pollutant Normal Operations (all receptors)										
NO_X	**1 hour**	**10.02371**	8.88642	7.92782	9.29226	8.17985	8.92124	8.51586	7.61610	6.78989
	annual	0.04503	0.04357	0.04307	0.04178	0.04069	**0.06081**	0.03834	0.03867	0.03789
CO	**1 hour**	**7.21707**	6.50667	5.82219	6.64123	6.13489	6.49311	6.40784	5.34650	5.06331
	8 hour	3.72114	3.68330	3.49331	3.41986	3.50973	**4.09966**	3.31112	3.10671	3.05241
SO_2	**1 hour**	**2.98626**	2.65465	2.38030	2.77032	2.45845	2.68451	2.55331	2.25583	2.04826
	3 hour	2.00436	1.96384	1.89181	1.88944	1.84306	**2.13591**	1.75466	1.71943	1.62864
	24 hour	0.51445	0.55693	0.52814	0.47665	0.52125	**0.71084**	0.48625	0.48552	0.45657
	annual	0.00537	0.00521	0.00517	0.00498	0.00489	**0.00732**	0.00460	0.00458	0.00457
PM_{10}	**24 hour**	0.74598	0.91004	1.01320	0.67713	0.92498	**1.47900**	0.76568	0.94419	1.03783
	annual	0.01945	0.02127	0.02481	0.01770	0.02170	**0.03808**	0.01810	0.02228	0.02598
		Case A1	**Case A2**	**Case A3**	**Case B1**	**Case B2**	**Case B3**	**Case C1**	**Case C2**	**Case C3**

Table 7-6 Maximum Hourly NO_2 and CO Emissions

Pollutant and Averaging Time	Description: Turbine Load	FP10 Unit Exhaust Temperature (ºF)	FP10 Unit Exhaust Velocity (ft/s)	Emission Rate per FP10 Unit Turbine (lb/hr)	Simple Cycle Unit Exhaust Temperature (ºF)	Simple Cycle Unit Exhaust Velocity (ft/s)	Emission Rate per Simple Cycle Unit Turbine (lb/hr)
NO_X 1-hour	All turbines starting up with the remainder of the period at normal operations	334	47.9	38.7	750	37.2	29.0
CO 1-hour	All turbines starting up with the remainder of the period at normal operations	334	47.9	279.8	750	37.2	225.3

Table 7-7 Criteria Pollutant Sources and Emission Totals for the Worst Case Project Emissions Scenarios for All Averaging Times

Averaging Time	Pollutant	Two FP10 Unit turbines (lbs entire period)	Two Simple Cycle Unit turbines (lbs entire period)	Two Gas Preheaters (lbs entire period)	FP10 Turbines	Simple Cycle Turbines
1-hour	NO_X	32.6 (normal operations)	41.7 (normal operations)	0.30	NO_X and CO normal operations: 100% load operation (both FP10s) at 94°F ambient temperature NO_X and CO startup operations: One startup (both FP10s) with remainder of period at normal operations (100%, 20°F) SO_2: 100% load operation (both FP10s) at 20°F ambient temperature based on 1.0 gr total S/100 scf	NO_X and CO normal operations: 100% load operation (both SCs) at 20°F ambient temperature NO_X and CO startup operations: One startup (both SCs) with remainder of period at normal operations (100%, 20°F) SO_2: 100% load operation (both SCs) at 20°F ambient temperature based on 1.0 gr total S/100 scf
		77.4 (startup operations)	58.0 (startup operations)			
	CO	30.0 (normal operations)	30.0 (normal operations)	0.34		
		559.6 (startup operations)	450.6 (startup operations)			
	SO_2	13.4	12.4	0.028		

Averaging Time	Pollutant	Two FP10 Unit turbines (lbs entire period)	Two Simple Cycle Unit turbines (lbs entire period)	Two Gas Preheaters (lbs entire period)	FP10 Turbines	Simple Cycle Turbines
3-hour	SO_2	40.2	37.2	0.084	SO_2: 100% load operation (both FP10s) at 20°F ambient temperature based on 1.0 gr total S/100 scf	SO_2: 100% load operation (both FP10s) at 20°F ambient temperature based on 1.0 gr total S/100 scf
8-hour	CO	1,577.20	1,935.60	2.72	CO: Two startups, one shutdown (both FP10s) with remainder of period at 100% load operation at 20°F ambient temperature	CO: Three startups, two shutdown (both SCs) with remainder of period at 100% load operation at 20°F ambient temperature
24-hour	PM_{10}	486.00	428.60	0.720	PM_{10}: Three startups, three shutdowns (both FP10s) with remainder of period at 100% load operation at 20°F ambient temperature	PM_{10}: Three startups, two shutdowns (both FP10s) with remainder of period at 100% load operation at 20°F ambient temperature
	SO_2	308.60	292.60	0.672	SO_2: 100% load operation (both FP10s) at 20°F ambient temperature based on 1.0 gr total S/100 scf	SO_2: Three startups, two shutdowns (both SCs) with remainder of period at 100% load operation at 20°F ambient temperature based on 1.0 gr total S/100 scf
Annual	NO_X	154,206.00	39,762.00	1,314	All: both FP10 units operate for 4,000 hours with power augmentation and evaporative cooling on at 94°F, 322 hours at full load at 59°F, with 193 startups and shutdowns. SO_2 emissions are based on 0.4 gr total S/100 scf.	All: both SC units operate at full load for 849 hours at 59°F, with 100 startups and shutdowns. SO_2 emissions are based on 0.4 gr total S/100 scf.
	PM_{10}	78,800.80	15,676.00	129		
	SO_2	21,041.20	4,278.00	49		

Table 7-8 Criteria Pollutant Sources and Emission Totals for the Worst Case Project Emissions Scenarios for All Averaging Times for Each Turbine

Averaging Time	Worst-Case Emission Scenarios by Operating Equipment	Pollutant	Emissions in pounds – Entire Period	
			FP10 Units/ Turbine	Simple Cycle Units /Turbine
1-hour	**NO_X:** Startup hour **CO:** Startup hour **SO_2 (1 gr/100 scf):** **(FP10)** Startup hour **(Simple Cycle Units)** operation at 20°F ambient temperature **PM_{10}:** **(FP10)** Startup hour **(Simple Cycle Units** Shutdown hour	NO_X	38.7	29.0
		CO	279.8	225.3
		SO_2	6.7	6.2
		PM_{10}	11.1	9.1
3-hour	**SO_2 (1 gr/100 scf):** **(FP10)** 3 startups. **(Simple Cycle Units)** 3 startups, 2 shutdowns	SO_2	20.1	18.6
8-hour	**CO:** **(FP10)** two startups, one shutdown and remainder of period at full load operation at 20°F ambient temperature **(Simple Cycle Units)** three startups, two shutdown and remainder of period at full load operation at 20°F ambient temperature	CO	788.6	967.8
24-hour	**SO_2 (1 gr/100 scf):** continuous full-load turbine operation at 20ºF ambient temperature	SO_2	154.3	149.0
	PM_{10}: **(FP10)** three startups, three shutdowns, and the remainder of the period at continuous full-load turbine operation at 20ºF ambient temperature. **(Simple Cycle Units)** three startups, two shutdowns, and the remainder of the period at continuous full-load turbine operation at 20ºF ambient temperature.	PM_{10}	243.0	214.3

Table 7-9 AERMOD Modeling Results for Project Operations (All Project Sources Combined)

Pollutant	Averaging Period	Maximum Predicted Impact (μg/m³)	Significant Air Quality Impacts[6] (μg/m³)	Background Concentration (μg/m³)[1]	Total Concentration (μg/m³)	NAAQS (μg/m³)	CAAQS (μg/m³)	Maximum UTMX NAD27 (m)	Maximum UTMY NAD27 (m)
NO_2	1-hour[2]	31.7 (normal operations)	19	122.1	154	NA	339[5]	608,569	4,208,310
		48.1 (startup operations)	NA	122.1	170	NA	339[5]	601,075	4,203,000
	Annual[2]	0.3	1.0	22.4	23	100	57[5]	608,593	4,208,311
SO_2	1-hour	6.6	NA	235.8	242	NA	655	601,700	4,200,525
	3-hour	3.4	25	114.4	118	1300	NA	608,569	4,208,485
	24-hour	1.1	5	26.3	27	365	105	608,569	4,208,485
	Annual	0.02	1.0	5.3	5	80	NA	609,106	4,208,140
CO	1-hour	36.3 (normal operations)	2,000	4,715	4,751	40,000	23,000	608,569	4,208,311
		352.3 (startup operations)	NA	4,715	5,067	40,000	23,000	601,075	4,203,000
	8-hour	53.3	500	2,222	2,275	10,000	10,000	608,556	4,208,465
PM_{10}	24-hour[3,4]	1.78	5	84.0	86	150	50	602,200	4,201,325
	Annual[3,4]	0.08	1.0	22.0	22	NA	20	609,131	4,208,140
$PM_{2.5}$	24-hour[3,4]	1.78	NA	74.0	76	35	NA	602,200	4,201,325
	Annual[3,4]	0.08	NA	12.0	12	15	12	609,131	4,208,140

Notes:
[1] Background represents the maximum values measured at the monitoring stations
[2] Results for NO_2 during operations used ozone limiting method (OLM) with ambient ozone data collected at the Bethel Island monitoring station for the years 2000-2002 and 2004-2005.
[3] PM_{10} and $PM_{2.5}$ background levels exceed ambient standards.
[4] All PM_{10} emissions from project sources were also considered to be $PM_{2.5}$.
[5] In February 2007, CARB approved new, more stringent CAAQS for NO_2 as shown in the table above. These changes became effective in March 2008.
[6] Significant Air Quality Impact is applicable only for normal operations.

Table 7-10 Duration and Criteria Pollutant Emissions for Commissioning of a Single Simple Cycle Unit (9 ppm ULN) on Natural Gas at 59°F

Activity	Duration (hours)	GT Load (%)	Modeling Load (%)	Total Emission			
				NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
CTG Testing (Full Speed No Load, FSNL, Excitation Test, Dummy Synch Checks)	8	0	0	339	19,240	1,181	71
CTG 1 Testing at 40% load	8	0-40	40	1,507	11,662	636	91
CTG 1 Load Test	68	50-100	50-101	6,615	25,673	1,620	624
Install Emissions Test Equipment	0	0	0	0	0	0	0
Emissions Tuning/Drift Testing	24	50-100	100	1,988	5,344	286	234
RATA/Pre-performance Testing/Source Testing/Drift Testing	60	100	100	4,970	13,360	715	585
Remove emissions test equipment/install performance test equipment, followed by Water Wash & Performance preparation	0	0	0	0	0	0	0
Performance Testing	40	100	100	3,035	5,628	328	365
CAISO Certification	12	50-100	100	994	2,672	143	117
CAISO Certification if required	12	100	100	994	2,672	143	117

Notes:
SO_X emission during commissioning will not be higher than normal operation
CTG = combustion turbine generator
FSNL = full speed, no load
GT = gas turbine

Table 7-11 Duration and Criteria Pollutant Emissions for Commissioning of a Single Flex Plant 10 (20 ppm ULN) on Natural Gas at 62°F

Activity	Duration (hours)	GT Load (%)	Modeling Load (%)	Total Emission			
				NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
GT Testing (FSNL, Excitation Test, Dummy Synch Checks)	8	0	FSNL	366	29,743	1275	75
GT Testing at 40% load	8	0-40	40	1,444	16,091	612	86
Steam Blow/HRSG Tuning	24	0-25	25	2,701	51,960	1637	222
Steam Blow	12	0-50	50	964	8,745	682	107
Steam Blow restoration, install SCR/CO Catalyst	0	0	0	0	0	0	0
HRSG Tuning/BOP Tuning	16	60	60	191	1,320	155	135
BOP Tuning	16	60	60	191	1,320	155	135
GT Load Test & Bypass Valve Tuning	32	60	60	382	2640	310	270
GT Load Test & Bypass Valve Tuning/ Safety Valve Testing	12	75	75	179	1,160	95	105
GT Base Load/Commissioning of Ammonia system	12	100	100	365	1,189	104	117
GT Load Test & Bypass Valve Tuning	12	100	100	365	1,189	104	117
Install Emissions Test Equipment	0	0	0	0	0	0	0
Bypass Operation/STG Initial Roll & Trip Test	10	0-60	60	149	1,227	123	87
Bypass Operation/STG Load Test	32	0-60	60	647	2,545	269	285
Combined-Cycle testing/Drift Test	48	0-100	100	1,184	1,513	199	415
Emissions Tuning/Drift Test	24	50-100	100	730	2,378	208	234
Pre-performance Testing/Drift Test	36	100	100	1,095	3,567	312	351
RATA/Pre-performance Testing/Source Testing	15	100	100	433	1,216	112	142
Pre-performance/Source Testing	26	50-100	100	776	2,396	213	250
Remove Emissions Test Equipment followed by Water Wash & Performance preparation	0	0	0	0	0	0	0
Performance Testing	48	100	100	1,276	2,594	272	432
CAISO Certification	24	50-100	100	730	2,378	208	234
GT Testing (FSNL, Excitation Test, Dummy Synch Checks)	8	0	FSNL	366	2,9743	1,275	75

Notes:
SO_X emission during commissioning will not be higher than normal operation
CT = combustion turbine
CTG = combustion turbine generator
FSNL = full speed, no load

Table 7-12 Project Commissioning Modeling Results

Modeling Scenario[4]	Pollutant	Averaging Period	Maximum Estimated Impact (μg/m³)	Background[1] (μg/m³)	Total Predicted Concentration (μg/m³)	Most Stringent Standard (μg/m³)
Simple Cycle Turbines commissioning only	CO	1 hour	1,678.4	4,715	6,393.4	23,000
		8 hours	1,060.6	2,222	3,282.6	10,000
	NO_2[3]	1 hour	88.9	122.1	211.0	339[2]
FP10 Turbines commissioning with fuel gas heater while Simple Cycle turbines undergo startup with fuel gas heater	CO	1 hour	3,662.1	4,715	8,377.1	23,000
		8 hours	1,349.2	2,222	3,571.2	10,000
	NO_2[3]	1 hour	177.4	122.1	299.5	339[2]

Notes:
[1] Background represents the maximum values measured at the monitoring stations.
[2] In February 2007, the CARB approved new, more stringent CAAQS for NO_2. The new standards of 339 μg/m³ (1 hour) and 57 μg/m³ (annual) became effective in March 2008.
[3] NO_2 modeling for Commissioning was conducted with the OLM algorithm.
The SC units are expected to be operational by July 2011, while the FP10 units are expected to be operational by June 2012.
CO = carbon monoxide
μg/m³ = micrograms per cubic meter
NO_2 = nitrogen dioxide

8.0 BACT ANALYSIS

Federal requirements pertaining to control of pollutants subject to PSD review (i.e., attainment pollutants) were promulgated by U.S.EPA in 40 CFR 51.21 (j). This regulation defines BACT as emission limits "based on maximum degree of reduction for each pollutant." BACT determinations are made on case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs. Federal requirements pertaining to control non-attainment pollutants, or Lowest Achievable Emission Rate (LAER), were promulgated by U.S.EPA under 40 CFR 51.165 (a). This regulation defines LAER as the emissions limit based on either (1) the most stringent emission rate contained in State Implementation Plan, unless the source demonstrates the rate is not achievable; or (2) the most stringent emissions limitation that is achieved in practice. The federal LAER does not consider the cost impacts of the control implementation.

Per BAAQMD regulation 2-2-301, the application of BACT is required for any new or modified emissions unit if the new unit or modification results in an increase in permitted daily emissions greater than 10 pounds per day for a specific criteria pollutant. BACT is defined in Rule 2-2-206 as the most stringent emission limitation or control technique of the following:

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

206.2 The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or

206.3 Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO; or

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

The primary air emission sources for the proposed project are the two FP10 units, two Simple Cycle gas turbines. Each combined-cycle power block consists of one Siemens Flex Plant 10 (FP10). The steam produced by the each HRSG will be sent to an individual steam turbine generator (STG). Each Simple Cycle power block consists of one Siemens SSC6-5000F Simple Cycle unit. The proposed project will have emissions in excess of 10 pounds per day (lb/day) for NO_X, VOC, CO, PM_{10}, and SO_X. Therefore, BACT will be required for these pollutants.

The MLGS project proposes for NO_x control the use of Ultra dry-low-NO_x combustors and SCR with ammonia injection. This section contains the BACT analysis conducted for the proposed project, and demonstrates the proposed BACT limit for each CTG as shown in Table 8-1.

BACT Assessment Methodology

The BACT assessment conducted for the proposed project considered all NO_x and CO control technologies currently proposed or in use on large natural gas-fired combustion turbine. To identify feasible emission limits, several information sources were consulted, including the following:

- US EPA's BACT/LAER Clearinghouse and updates;

- CARB's BACT Clearinghouse database and CARB's BACT Guidelines for Power Plant;
- South Coast Air Quality Management District (SCAQMD) BACT Guidelines Manual;
- BAAQMD BACT Guidelines Manual; and
- Recent CEC Applications for Certification;

Table 8-2 list s the BACT guidelines from BAAQMD for the FP10 and simple cycle CTG respectively.

The project must comply with the requirements of the BAAQMD's permit regulations requiring the application of the Best Available Control Technology (BACT) to control air emissions. To comply with the BAAQMD's BACT requirements for oxides of nitrogen (NO_x), the project's design includes ultra low NO_x combustion controls on the gas turbines and selective catalytic reduction (SCR) to control NO_x emissions. To comply with BAAQMD's BACT requirements for carbon monoxide (CO) and VOC, a CO catalyst would be employed.

8.1 *NO_x Control Technologies*

Based on a review of materials described above, the following NO_x emission control technologies are considered for the project. Potential NO_x control technologies for combustion gas turbines include the following:

Combustion controls

- Dry combustion controls
- Wet combustion controls
- Catalytic combustors (e.g., XONON)

Post-combustion controls

- Selective catalytic reduction (SCR)
- Selective non-catalytic reduction (SNCR)
- Non-selective catalytic reduction (NSCR)
- SCONOx™

The technical feasibility of available NO_x control technologies are presented below.

Dry Combustion Controls

Combustion modifications that lower NO_x emissions without wet injection include lean combustion, reduced combustor residence time, lean premixed combustion, and two-stage rich/lean combustion. Lean combustion uses excess air (greater than stoichiometric air-to-fuel ratio) in the combustor's primary combustion zone to cool the flame, thereby reducing the rate of thermal NO_x formation. Reduced combustor residence times are achieved by introducing dilution air between the combustor and the turbine sooner than with standard combustors. The combustion gases are at high temperatures for a shorter time, which also has the effect of reducing the rate of thermal NO_x formation. Dry ultra low NO_x combustion would be used on the Siemens 5000F gas turbines for this project.

Wet Combustion Controls

Steam or water injection directly into the turbine combustor is one of the most common NO_x control techniques. These wet injection techniques lower the peak flame temperature in the combustor, reducing the formation of thermal NO_x. The injected water or steam exits the turbine as part of the exhaust. Although the lower peak flame temperature has a beneficial effect on NO_x

emissions, it can also reduce combustion efficiency and prevent complete combustion. As a result, emissions of carbon monoxide (CO) and volatile organic compounds (VOCs) increase as water/steam injection rates increase.

Water and steam injection have been in use on both oil- and gas-fired combustion turbines in all size ranges for many years, so these NO_x control technologies are generally considered technologically feasible and widely available. Since dry low NO_x combustion controls are used in the Siemens 5000F gas turbines and are more effective than water injection, water injection is not considered for this project.

Catalytic combustors

Catalytic combustors use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. This technology has been commercially demonstrated under the trade name XONON in a 1.5-MW natural gas-fired combustion turbine in Santa Clara, California. The technology has not been announced as being commercially available for the engines used at MLGS. No turbine vendor, other than Kawasaki, has indicated the commercial availability of catalytic combustion systems at the present time and the largest size is 18 MW; therefore, catalytic combustion controls are not commercially available in the size range for this specific project and are not discussed further.

Selective catalytic reduction (SCR)

Selective catalytic reduction is a post-combustion technique that controls both thermal and fuel-bound NO_x emissions by reducing NO_x with a reagent (generally ammonia or urea) in the presence of a catalyst to form water and nitrogen. NO_x conversion is sensitive to exhaust gas temperature, and performance can be limited by contaminants in the exhaust gas that may mask the catalyst (sulfur compounds, particulates, heavy metals, and silica). SCR is used in numerous gas turbine installations throughout the United States, almost exclusively in conjunction with other wet or dry NO_x combustion controls. SCR requires the consumption of a reagent (ammonia or urea) and requires periodic catalyst replacement. Estimated levels of NO_x control are in excess of 90 percent. SCR would be used on this project in conjunction with the dry ultra low NO_x combustion controls on the Siemens 5000F gas turbine.

Selective non-catalytic reduction (SNCR)

Selective non-catalytic reduction (SNCR) involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,200°F to 2,000°F and is most commonly used in boilers. Some method of exhaust gas reheat, such as additional fuel combustion, would be required to achieve exhaust temperatures compatible with SNCR operations, and this requirement makes SNCR technologically infeasible for MLGS.

Nonselective catalytic reduction (NSCR)

Nonselective catalytic reduction (NSCR) uses a catalyst without injected reagents to reduce NO_x emissions in an exhaust gas stream. NSCR is typically used in automobile exhaust and rich-burn stationary internal combustion (IC) engines, and employs a platinum/rhodium catalyst. NSCR is effective only in a stoichiometric or fuel-rich environment where the combustion gas is nearly depleted of oxygen, and this condition does not occur in turbine exhaust where the oxygen concentrations are typically between 14 and 16 percent. For this reason, NSCR is not technologically feasible for the MLGS.

SCONOX™

SCONOx™ is a proprietary catalytic oxidation and adsorption technology that uses a single catalyst for the control of NO_x, CO, and VOC emissions. The catalyst is a monolithic design, made from a ceramic substrate with both a proprietary platinum-based oxidation catalyst and a potassium carbonate adsorption coating. The catalyst simultaneously oxidizes NO to NO_2, CO to CO_2, and VOCs to CO_2 and water, while NO_2 is adsorbed onto the catalyst surface where it is chemically converted to and stored as potassium nitrates and nitrites. The SCONOx potassium carbonate layer has a limited adsorption capability and requires regeneration approximately every 12 to 15 minutes in normal service. Each regeneration cycle requires approximately 3 to 5 minutes. At any point in time, approximately 20 percent of the compartments in a SCONOx system would be in regeneration mode, and the remaining 80 percent of the compartments would be in oxidation/absorption mode.

There are serious questions about the probability of a successful application of the SCONOx technology for application to MLGS, as well as the levels of emission control that can be consistently achieved. Therefore, this technology is not considered feasible for MLGS. CEC staff has determined in other recent citing cases that SCONOx is not a preferable alternative, stating: "Applicant also reviewed alternative technologies for air pollution control and combustion modification, including: … SCONOx. None of the alternative pollution control technologies is more effective than that proposed for the project due to their lack of commercial viability in a scaled-up project and/or their technological infeasibility for a peaking unit. (…) Therefore, the evidence shows that none of the alternative fuels or technologies is a feasible option" (CEC, 2006).

As discussed above, the project's design includes ultra low NO_x combustion controls on the gas turbines and selective catalytic reduction (SCR) to comply with the BAAQMD's BACT requirements for NO_x.

8.2 *CO and VOC Control Technologies*

BACT for CO emissions from all power blocks will be achieved by using oxidation catalysts as a post-combustion control technology to reduce CO emissions to 3.0 ppmvd, corrected to 15 percent O_2. BAAQMD's BACT determinations indicate that BACT from large, simple-cycle combustion turbines (≥40 MW) is 6.0 ppmvd CO (at 15 percent O_2). As or the combined-cycle combustion turbines, BACT determination is at 4.0 ppmvd CO (at 15 percent O_2). Therefore, the proposed combustion turbines will meet the BACT requirements for CO.

As recommended in BAAQMD's BACT determination, BACT for VOC emissions will be achieved by use of oxidation catalysts as a post-combustion control technology to reduce VOC emissions to 2.0 ppmvd for each of the four power blocks. By achieving this level of control each of the proposed combustion turbines will meet the BACT requirements for CO (3.0 ppmvd, corrected to 15 percent O_2).

8.3 *SO_2 Control Technologies*

BAAQMD BACT Guidelines 89.1.3 and 89.1.6 specifies BACT determination for SO_2 for both simple and combined-cycle combustion turbines with an output rating of ≥ 40 MW as the exclusive use of clean-burning natural gas with a sulfur content of < 1.0 grains per 100 scf. The proposed turbines will exclusively burn pipeline-quality natural gas that will be delivered by PG&E with an expected average sulfur content of 0.40 grains per 100 scf, which will result in minimal SO_2 emissions.

8.4 *PM_{10} Control Technologies*

BACT for PM_{10} is the exclusive use of pipeline-quality natural gas. The proposed turbines will exclusively burn pipeline-quality natural gas that will be delivered by PG&E. Therefore, the proposed combustion turbines will meet the BACT requirements for PM_{10}.

8.5 *Fugitive Dust Control*

Other controls that will be implemented at the MLGS project site include best achievable control measures (BACM) during construction period.

Fugitive dust emissions resulting from onsite soil disturbances during construction were estimated using Midwest Research Institute (MRI), 1996 emission factors for bulldozing and dirt-pushing, travel on unpaved roads, and handling/storage of aggregate materials. A dust control efficiency of 83.23 percent for project site and temporary construction area activities was assumed to be achieved for these activities by frequent watering or other measures when required to satisfy BAAQMD Regulation 6.

Table 8-1 Summary of Proposed BACT

Pollutant	Control Technology	Concentration
FP10 Units		
NO_X	Ultra low NO_X burner, SCR	2.0 ppmvd (1-hour average) at 15 percent O_2
CO	Catalytic oxidation	3.0 ppmvd at 15 percent O_2
VOC	Catalytic oxidation	2.0 ppmvd at 15 percent O_2
SO_2	Pipeline quality natural gas	N/A
PM_{10}	Pipeline quality natural gas	N/A
Ammonia slip	Operational limitation	5.0 ppmvd at 15 percent O_2
Simple Cycle Units		
NO_X	Ultra low NO_X burner	2.5 ppmvd (1-hour average) at 15 percent O_2
CO	Catalytic oxidation	3.0 ppmvd at 15 percent O_2
VOC	Catalytic oxidation	2.0 ppmvd at 15 percent O_2
SO_2	Pipeline quality natural gas	N/A
PM_{10}	Pipeline quality natural gas	N/A
Ammonia slip	Operational limitation	10.0 ppmvd at 15 percent O_2

Notes:

BACT = Best Available Control Technology
CO = carbon monoxide
NA = not applicable
NO_X = nitrogen oxides
O_2 = oxygen
PM_{10} = particulate matter less than or equal to 10 microns in diameter
ppm = parts per million
SCR = Selective catalytic reduction
VOC = Volatile organic compounds
SO_2 = sulfur dioxide

Table 8-2 BACT Determination for the MLGS Emission Sources

Determination #	***89.1.3***		***89.1.6***	
Turbine Category	***Simple Cycle (> = 40 Megawatts)***		***FP10 ($\geq$ 40 Megawatts)***	
Pollutant	**BACT**	**Typical Technology**	**BACT**	**Typical Technology**
	1. Technologically Feasible/ Cost Effective		**1. Technologically Feasible/ Cost Effective**	
	2. Achieved in Practice		**2. Achieved in Practice**	
VOC	1. n/d	1. n/d	1. n/d	1. n/d
	2. 2.0 ppmv, Dry at 15%O_2	2. Oxidation Catalyst	2. 2.0 ppm, Dry at 15%O_2	2. Oxidation Catalyst, or Efficient Ultra Low NO_X Combustors
NO_X	1. n/d	1. n/d	1. 2.0 ppm, Dry at 15% O_2	1. SCR+ Low NO_X Combustors, or Water or Steam Injection, or a SCONOX System
	2. 2.5 ppmv, Dry at 15%O_2	2. High Temperature SCR + Water or Steam Injection		2. SCR+ Dry Low-NO_X Combustors
SO2	1. Natural Gas Fuel	1. Exclusive use of CPUC-regulated grade natural gas		
		2. Exclusive use of CPUC-regulated grade natural gas	2. 2.5 ppm, Dry at 15% O_2	
	2. Natural Gas Fuel		1. n/d	1. n/d

Table 8-2 BACT Determination for the MLGS Emission Sources (Page 2 of 2)

Determination #	***89.1.3***		***89.1.6***	
Turbine Category	***Simple Cycle (> = 40 Megawatts)***		***Combined-Cycle (≥ 40 Megawatts)***	
Pollutant	**BACT**	**Typical Technology**	**BACT**	**Typical Technology**
	1. Technologically Feasible/ Cost Effective		**1. Technologically Feasible/ Cost Effective**	
	2. Achieved in Practice		**2. Achieved in Practice**	
CO	1. n/d	1. n/d	2. Natural Gas Fuel (sulfur content not to exceed 1.0 grain/100 scf)	2. Exclusive use of PUC-regulated grade natural gas
	2. 6.0 ppmv, Dry @15% O_2	2. Oxidation Catalyst	1. n/d	1. n/d
PM_{10}	1. Natural Gas Fuel	1. Exclusive use of CPUC-regulated grade natural gas	2. 4.0 ppm, Dry @15% O_2	2. Oxidation Catalyst
		2. Exclusive use of CPUC-regulated grade natural gas	1. n/d	1. n/d
	2. Natural Gas Fuel		2. Natural Gas Fuel (sulfur content not to exceed 1.0 grain/100 scf)	2. Exclusive use of PUC-regulated grade natural gas
NPOC	1. n/a	1. n/a	1. n/a	1. n/a
	2. n/a	2. n/a	2. n/a	2. n/a

Notes:
n/a = not applicable
n/d = no determination

9.0 HEALTH RISK ASESSMENT

This section describes the evaluation of potential public health risks due to demolition, construction, and operation of the proposed power generation facility and the methodology and results of the HRA. A significant impact is defined as a maximum incremental cancer risk greater than 10 in 1 million, a chronic total hazard index (THI) greater than 1.0, or an acute THI greater than 1.0. Also, uncertainties in the HRA are discussed and other potential health impacts of the project are described.

9.1 *Public Health Impact Assessment Approach*

The potential human health risks posed by the project's emissions were assessed using procedures consistent with the BAAQMD Risk Assessment Procedures for Regulation 2, Rule 5 (BAAQMD, 2005a), BAAQMD Air Toxics NSR Program Health Risk Screening Analysis (HRSA) Guidelines (BAAQMD, 2005b), Office of Environmental Health Hazard Assessment (OEHHA) Air Toxics Hot Spots Program Risk Assessment Guidelines (Cal-EPA/OEHHA, 2002) and guidance from BAAQMD staff. The BAAQMD and OEHHA guidelines were developed to provide risk assessment procedures, as required under the Air Toxics Hot Spots Information and Assessment Act of 1987, Assembly Bill 2588 (Health and Safety Code Sections 44360 et seq.). The Hot Spots law established a statewide program to inventory air toxics emissions from individual facilities, as well as guidance for execution of risk assessments and requirements for public notification of potential health risks.

As recommended by BAAQMD staff and OEHHA Guidelines, the California Air Resources Board (CARB) Hotspots Analysis and Reporting Program (HARP) was used to perform an OEHHA Tier 1 HRA for the project. HARP includes two modules: a dispersion module and a risk module. The HARP dispersion module incorporates the USEPA ISCST3 air dispersion model, and the HARP risk module implements the latest Risk Assessment Guidelines developed by OEHHA. For consistency with the criteria pollutant modeling, the dispersion modeling was conducted with AERMOD. CARB has created a beta version software package, HARP File Converter, to convert AERMOD dispersion results into a format that can be read into the HARP risk module. Thus, HARP with AERMOD was used for this HRA.

The HRA was conducted in four steps using the HARP:

1. Hazard identification and emission quantification
2. Exposure assessment
3. Dose-response assessment
4. Risk characterization

First, hazard identification was performed to determine the potential health effects that could be associated with MLGS emissions. The purpose was to identify whether pollutants emitted during MLGS operation could be characterized as potential human carcinogens, or associated with other types of adverse health effects. Based on BAAQMD and OEHHA guidelines, a list of pollutants with potential cancer and noncancer health effects associated with the emissions from the project has been constructed in Table 9-1. Note that the two Flex Plant 10 (FP10), the two Simple Cycle turbines and the two natural gas-fired preheaters are the only sources of TACs associated with normal MLGS operations and that the same group of TACs are emitted by the aforementioned sources.

Second, an exposure assessment was conducted to estimate the extent of public exposure to the project emissions. Public exposure is quantified based on the predicted maximum short- and long-term ground-level concentrations resulting from project emissions, the exposure pathway(s), and the duration of exposure to those emissions. Dispersion modeling was performed using the AERMOD model to estimate the highest ground-level concentrations near the project site. The methods used in the dispersion modeling were consistent with the approach described in Section 7. and the modeling protocol submitted for the project to CEC and BAAQMD (URS, 2008).

Third, a dose-response assessment was performed in HARP incorporating the maximum 1-hour and annual ground level concentrations predicted by AERMOD to characterize the relationship between pollutant exposure and the potential incidence of an adverse health effect in the exposed populations. The dose-response relationship is expressed in terms of potency factors for cancer risk and reference exposure levels (RELs) for acute and chronic noncancer risks. The OEHHA guidelines provide potency factors and RELs for an extensive list of TACs, including those listed in Table 9-1. All exposure pathways were included in this analysis, except the beef/dairy pasture pathways, because no cattle exist within 10 km of the project site. For the drinking water pathway, the Contra Loma and Antioch Municipal Water Reservoirs were included in the HRA. Fish consumption was assumed to come from the San Joaquin River. For the calculation of cancer risk, the duration of exposure to project emissions was assumed to be 24 hours per day, 365 days per year, for 70 years, at all receptors. The cancer risk was calculated in HARP using the Derived (Adjusted) Method, and the chronic THI was calculated in HARP using the Derived (OEHHA) Method.

Fourth, risk characterization was performed to integrate the health effects and public exposure information and provide qualitative estimates of health risks resulting from project emissions. Risk modeling was performed using HARP to estimate cancer and noncancer health risks due to project operational emissions. The HARP model uses OEHHA equations and algorithms to calculate health risks based on input parameters such as emissions, “unit” ground-level concentrations, and toxicological data.

Detailed descriptions of the model input parameters and results of the HRA are given in Section 9.4.

9.2 *Construction Phase Emissions*

Due to the relatively short duration of the project demolition and construction (i.e., 33 months), significant long-term public health effects are not expected to occur as a result of project construction emissions. Of air pollutants emitted during the construction period, diesel particulate matter (DPM) has the largest potential for human health risk. DPM has been classified by CARB and OEHHA as a TAC and a carcinogen. However, the exposure assessment conducted for carcinogens is typically 70 years. Due to the short duration of the construction effort, significant carcinogenic health risks are not predicted for the construction period.

During the demolition of the existing structures, some asbestos may be encountered. Emissions of asbestos when structures are demolished will be less than significant due to the prior removal of all regulated asbestos-containing material in compliance with BAAQMD Regulation 11, Rule 2, Asbestos Demolition, Renovation, and Removal.

9.3 *Operational Phase Emissions*

Facility operations were evaluated to determine whether particular substances would be used or generated at the project site that could cause adverse health effects upon their release to the air. The only sources of TAC emissions associated with facility operations would be the four natural-gas–fired combustion turbine generators (CTGs) and two preheaters.

The substances that would be emitted from facility operations with potential toxicological impacts are shown in Table 9-1. These air toxic species were identified in the list of emission factors published in *California Air Toxics Emission Factor* (CATEF) (CARB, 1996) and U.S. EPA AP-42 (U.S. EPA, 1995). In addition, potential emissions from ammonia slip from the turbine/heat recovery steam generator HRSG selective catalytic reduction (SCR) systems were included.

Worst-case estimates of annual turbine emissions of TACs were made by assuming that:

Each FP10 turbine would operate with a maximum higher heating value (HHV) fuel energy input rate of 2,271 MMBtu/hr (100 percent load, 20°F) for 4,383 hours per year.

Each Simple Cycle turbine would operate with a maximum HHV fuel energy input rate of 2,202 million British thermal units per hour (MMBtu/hr) (100 percent load at 20 F), for 877 hours per year.

Each natural gas-fired preheater would operate with a maximum higher heating value (HHV) fuel energy input rate of 5.0 MMBtu/hr (100 percent load, 20°F) and will operate during every hour of turbine operation(4,383 hours per year for S-5 and 877 hours per year for S-6).

Model simulations to estimate both hourly and annual average impacts used the following stack parameters:

For the FP10 units, exhaust temperature and stack exhaust velocity values corresponding to 100 percent load operations at an ambient temperature of 94°F with power augmentation and evaporative cooling.

For the Simple Cycle units, exhaust temperature and stack exhaust velocity values corresponding to 60 percent load at an ambient temperature of 60°F, with no evaporative cooling.

For the natural gas-fired preheaters, exhaust temperature and stack exhaust velocity values corresponding to operation at maximum capacity.

These emission parameter combinations were determined from the turbine screening modeling described in Section 7.0 to produce the highest ground-level impacts outside the project site. This parameter combination ensures that impacts from the HRA will not be underestimated for any operating condition.

Emission factors for natural-gas–fired turbines were obtained from the CATEF database for natural-gas–fired combustion turbines and for all substances that have a controlled emissions factor from the carbon monoxide (CO) catalyst from Table 3.4-1 in the background document for AP-42, Section 3.1, for natural-gas–fired combustion turbines. The emission factors and estimated maximum hourly and annual emissions from each FP10 combined-cycle CTG/HRSG are summarized in Table 4-7. Maximum hourly and annual emissions from each 5000F Simple Cycle CTG are presented in Table 4-8. Emission factors for natural gas-fired heaters were also obtained from the CATEF database and are utilized in the estimation of maximum hourly and annual TAC emissions from the fuel gas heater in Table 4-10.

Under the Clean Air Act, Section 112, a major source of hazardous air pollutants (HAPs) is a source that emits 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAPs. Therefore, the proposed Project is not a major source of HAPs.

9.4 *Model Input Parameters*

The HRA was conducted using worst-case turbine and preheater emissions (short-term and long-term). Cancer and chronic noncancer health effects were evaluated using the HARP model with estimated annual average emission rates for the Simple Cycle turbines, FP10 combined-cycle turbines, and preheaters. Acute noncancer health effects were analyzed based on the maximum hourly emissions from all sources.

Dispersion modeling was performed using the AERMOD model and methods consistent with the approach described in Section 7.0 (e.g., building downwash and meteorological input data), and the modeling protocol submitted for review to CEC and BAAQMD (URS, 2008). The AERMOD model is run with unit emission rates, 1 gram per second emissions, for each source to calculate the concentration of TACs per unit emission rate from each source. HARP then uses this information along with the estimated source emission rates for specific TAC compounds (as described above) to calculate ground-level concentrations for each chemical species. Meteorological data for the years 2000, 2001, 2002, 2004, and 2005 (the same years used in the air quality modeling analysis described in Section 7.0) were used in the HRA. Risk values were modeled for all sensitive receptors within 3 miles of the project site and at all grid and census receptors within 6 miles of the site. The same grid and refined receptors used in the air quality modeling were used in the HRA (see Section 7.0 for more details). The grid receptors extend 10 km in all directions from the project boundary, including receptors spaced every 25 meters (m) along the facility property line. Additional receptors were added on the hill approximately 6 km to the southwest of the project to ensure accurate pollutant concentrations were estimated by AERMOD in this area of complex terrain. To be certain that the maximum potential risks resulting from project emissions would be addressed, all receptors were treated as sensitive receptors.

Toxicological data, cancer potency factors, and RELs for specific chemicals are built into the CARB's HARP model. The pollutant-specific cancer potency factors and RELs used in the HRA are listed in Table 9-1. The HARP model uses the toxicological data in conjunction with the other input data described above to perform health risk estimates based on OEHHA equations and algorithms.

9.5 *Calculation of Health Effects*

Adverse health effects are expressed in terms of cancer or noncancer health risks. Cancer risk is typically reported as "lifetime cancer risk," which is the estimated maximum increase in the risk of developing cancer caused by long-term exposure to a pollutant suspected of being a carcinogen. The calculation of cancer risk conservatively assumes an individual is exposed continuously to the maximum pollutant concentrations 24 hours per day for 70 years. Although such continuous lifetime exposure to maximum TAC levels is unlikely, the goal of the approach is to produce a conservative worst-case estimate of potential cancer risk.

Noncancer risk is typically reported as a THI. The THI is calculated for each target organ as a fraction of the maximum acceptable exposure level or REL for an individual pollutant. The REL is generally the level at (or below) which no adverse health effects are expected. The THIs are calculated for both short-term (acute) and long-term (chronic) exposures to noncarcinogenic substances by adding the ratios of predicted concentrations to RELs for all pollutants.

Both cancer and noncancer risk estimates produced by the HRA represent incremental risks (i.e., risks due to the modeled sources only) and do not include potential health risks posed by existing background concentrations. The HARP model performs all of the necessary calculations to estimate the potential lifetime cancer risk and the acute and chronic noncancer THIs due to the project's TAC emissions.

9.6 *Health Effects Significance Criteria*

Various state and local agencies provide different significance criteria for cancer and noncancer health effects. For the project, the BAAQMD guidelines provide the significance criteria for potential cancer and noncancer health effects due to project-related emissions. BAAQMD Regulation 2, Rule 5 states that if a HRA for a project predicts a cancer risk of greater than 1.0 in one million (1.0×10^{-6}), and/or a chronic hazard index greater than 0.20, then Toxic Best Available Control Technology (TBACT) must be applied. For carcinogenic health effects, an exposure is considered significant when the predicted increase in lifetime cancer risk exceeds 10 in 1 million (1.0×10^{-5}). For noncarcinogenic acute and chronic health effects, an exposure that affects each target organ is considered significant when the corresponding THI exceeds a value of 1.0.

9.7 *Estimated Lifetime Cancer Risk*

The maximum incremental cancer risk resulting from project emissions was estimated to be 0.074 in 1 million, at a location approximately 13 m north of the MLGS property boundary (receptor located at 608,422 m east, 4,208,581 m north[1]). The peak cancer risk predicted at a sensitive receptor was 0.023 in 1 million, at the nearest residence, approximately 900 m southwest of the project boundary (608,016 m east, 4,207,668 m north). Table 9-2 presents the detailed cancer risk results of the HRA for the project operations.

The estimated cancer risks at all locations are well below the significance criterion of 10 in 1 million and the TBACT threshold of 1 in 1 million. Thus, the project emissions are expected to pose a less-than-significant increase in terms of carcinogenic health risk. All HARP and AERMOD model files are provided electronically on a DVD accompanying this application package.

9.8 *Estimated Chronic and Acute Total Hazard Indices*

The maximum chronic THI resulting from project's operational emissions was estimated to be 0.003 at a location approximately 13 m north of the MLGS property boundary (608,197 m east, 4,208,581 m north). The maximum predicted chronic THI at a sensitive receptor due to TAC emissions of the project was 0.001, at the nearest residence, approximately 900 m southwest of the project boundary (608,016 m east, 4,207,668 m north).

The maximum acute THI resulting from project emissions was estimated to be 0.072 at a location approximately 8 km southwest of the project (603,904 m east, 4,202,696 m north). The

[1] Coordinates are provided in accordance with the Universal Transverse Mercator and North American Datum, 1983, Zone 10.

maximum acute THI at a sensitive receptor was estimated to be 0.063, at the nearest residence, approximately 900 m southwest of the project boundary (608,016 m east, 4,207,668 m north). Table 9-2 presents the detailed noncancer results of the HRA for the project operations.

The estimated chronic and acute THIs are well below the significance criterion of 1.0 and the TBACT chronic threshold of 0.2. Thus, the project emissions of noncarcinogenic TACs would not be expected to pose a significant risk.

9.9 *Uncertainty in the Public Health Impact Assessment*

Sources of uncertainty in the results of HRAs include emissions estimates, dispersion modeling, exposure characteristics, and extrapolation of toxicity data in animals to humans. For this reason, assumptions used in HRAs are typically designed to provide sufficient health protection to avoid underestimation of risk to the public. Some sources of uncertainty applicable to this HRA and the procedures and assumptions used to ensure health-protective results are discussed below.

The turbine emission rates were derived using vendor data regarding ammonia slip rates and emission factors from CATEF and AP-42 for the other air toxics. Both the short- and long-term turbine emissions estimates were developed assuming that all turbines and fuel gas preheaters would operate continuously at the same time and at the maximum fuel energy input rate. Under actual operating conditions, the turbines and fuel gas preheaters would typically operate fewer hours per year and at lower loads. Consequently, the emissions used for this HRA are likely to be higher than what would be experienced under normal plant operation.

Dispersion models approved for regulatory applications contain assumptions that lead to overprediction of ground-level concentrations. For example, the modeling performed in the HRA assumed a conservation of mass (i.e., all of the pollutants emitted from the sources remained in the atmosphere while being transported downwind). During the transport of pollutants from sources toward receptors, none of the emitted material was assumed to be removed from the source plumes by means of chemical reactions or losses at the ground surface due to reactions, gravitational settling, or turbulent impaction. In reality, these mechanisms work to reduce the level of pollutants remaining in the atmosphere during plume travel.

The exposure characteristics assessed in the HRA included the assumption that residents would be exposed to turbine emissions continuously at the same location for 24 hours per day, 365 days per year, for 70 years. It is extremely unlikely that any resident would actually experience such exposure to the maximum predicted concentrations of TACs over this period. The conservative exposure assumption leads to overpredicted risk estimates in the HRA modeling.

The toxicity data used in the HRA contain uncertainties due to the extrapolation of health effects data from animals to humans. Typically, safety factors are applied when doing the extrapolation. Furthermore, the human population is much more diverse, both genetically and culturally, than bred experimental animals. The intraspecies variability is expected to be much greater among humans than in laboratory animals. With all of the uncertainty in the assumptions used to extrapolate toxicity data, significant measures are taken to ensure that sufficient health protection is built into the available health effects data.

Conservative measures to compensate for all of these uncertainties and ensure that potential health risks are not underestimated are compounded in the final HRA predictions. Therefore, the actual risk numbers are expected to be well below the values presented in this analysis.

9.10 *Criteria Pollutants*

The dispersion of the project's emissions of criteria pollutants (nitrogen dioxide, CO, sulfur dioxide, and particulate matter with an aerodynamic diameter of 10 and 2.5 microns or less [PM_{10} and $PM_{2.5}$]) was modeled, and an evaluation of their impacts on air quality is presented in Section 7.0. The federal and state AAQS set limits on the allowable levels of air pollutants in the ambient air necessary to protect public health. The results of the air quality analysis show that the project would not cause a violation of any state or federal AAQS and would not significantly contribute to existing violations of federal such standards. Therefore, no significant adverse health effects are anticipated to result from the project's criteria pollutant emissions.

Table 9-1 Toxicity Values Used To Characterize Health Risks

Compound	Sources of Emissions	Inhalation Cancer Potency Factor $(mg/kg\text{-}day)^{-1}$	Chronic REL ($\mu g/m^3$)	Acute REL ($\mu g/m^3$)
Ammonia	Turbines	—	2.0E+02	3.2E+03
1,3-Butadiene	Turbines	6.0E-01	2.0E+01	—
Acetaldehyde	Turbines and Preheaters	1.0E-02	9.0E+00	—
Acrolein	Turbines and Preheaters	—	6.0E-02	1.9E-01
Benzene	Turbines and Preheaters	1.0E-01	6.0E+01	1.3E+03
Ethylbenzene[1]	Turbines and Preheaters	8.7E-03	2.0E+03	—
Formaldehyde	Turbines and Preheaters	2.1E-02	3.0E+00	9.4E+01
Hexane	Turbines	—	7.0E+03	—
Propylene	Turbines and Preheaters	—	3.0E+03	—
Propylene oxide	Turbines	1.3E-02	3.0E+01	3.1E+03
Toluene	Turbines and Preheaters	—	3.0E+02	3.7E+04
Xylenes	Turbines and Preheaters	—	7.0E+02	2.2E+04
Polycyclic Aromatic Hydrocarbons (PAHs)				
Naphthalene	Turbines and Preheaters	1.2E-01	9.0E+00	—
Benzo(a)anthracene	Turbines and Preheaters	3.9E-01	—	—
Benzo(a)pyrene	Turbines and Preheaters	3.9E+00	—	—
Benzo(b)fluoranthene	Turbines and Preheaters	3.9E-01	—	—
Benzo(k)fluoranthene	Turbines and Preheaters	3.9E-01	—	—
Chrysene	Turbines and Preheaters	3.9E-02	—	—
Dibenz(a,h)anthracene	Turbines and Preheaters	4.1E-00	—	—
Indeno(1,2,3-cd)pyrene	Turbines and Preheaters	3.9E-01	—	—

Source: Cal-EPA/OEHHA, 2005 and 2007
Notes:
[1] In November 2007, OEHHA adopted the new ethylbenzene cancer potency factor presented above, but the HARP risk assessment module has not yet been updated to incorporate the new cancer risk factor for this pollutant.
— = not applicable
mg/kg-day = milligrams per kilogram per day
$\mu g/m^3$ = micrograms per cubic meter
REL = reference exposure levels

Table 9-2 Estimated Cancer Risk and Acute and Chronic Noncancer Total Hazard Indices Due to MLGS Emissions of TACs

Location	Cancer Risk	Chronic Hazard Index	Acute Hazard Index
Point of maximum impact	0.074 excess risk in 1 million	0.003 total hazard index	0.072 total hazard index
Peak risk at a sensitive receptor	0.023 excess risk in 1 million	0.001 total hazard index	0.063 total hazard index

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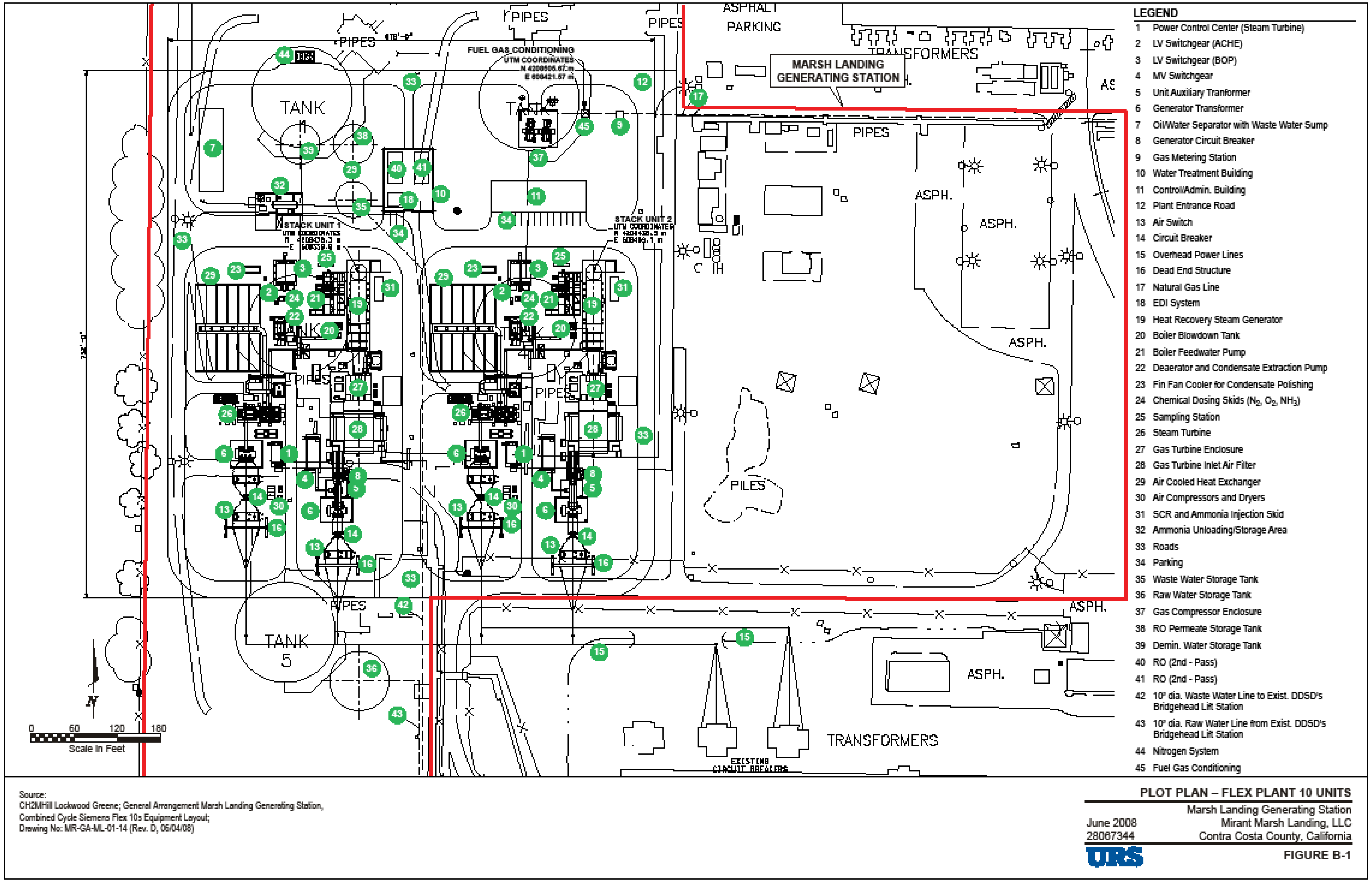
Appendix B. Additional Plot Plan Figures

Appendix B Additional Plot Plan Figures

Marsh landing Generating Station Project



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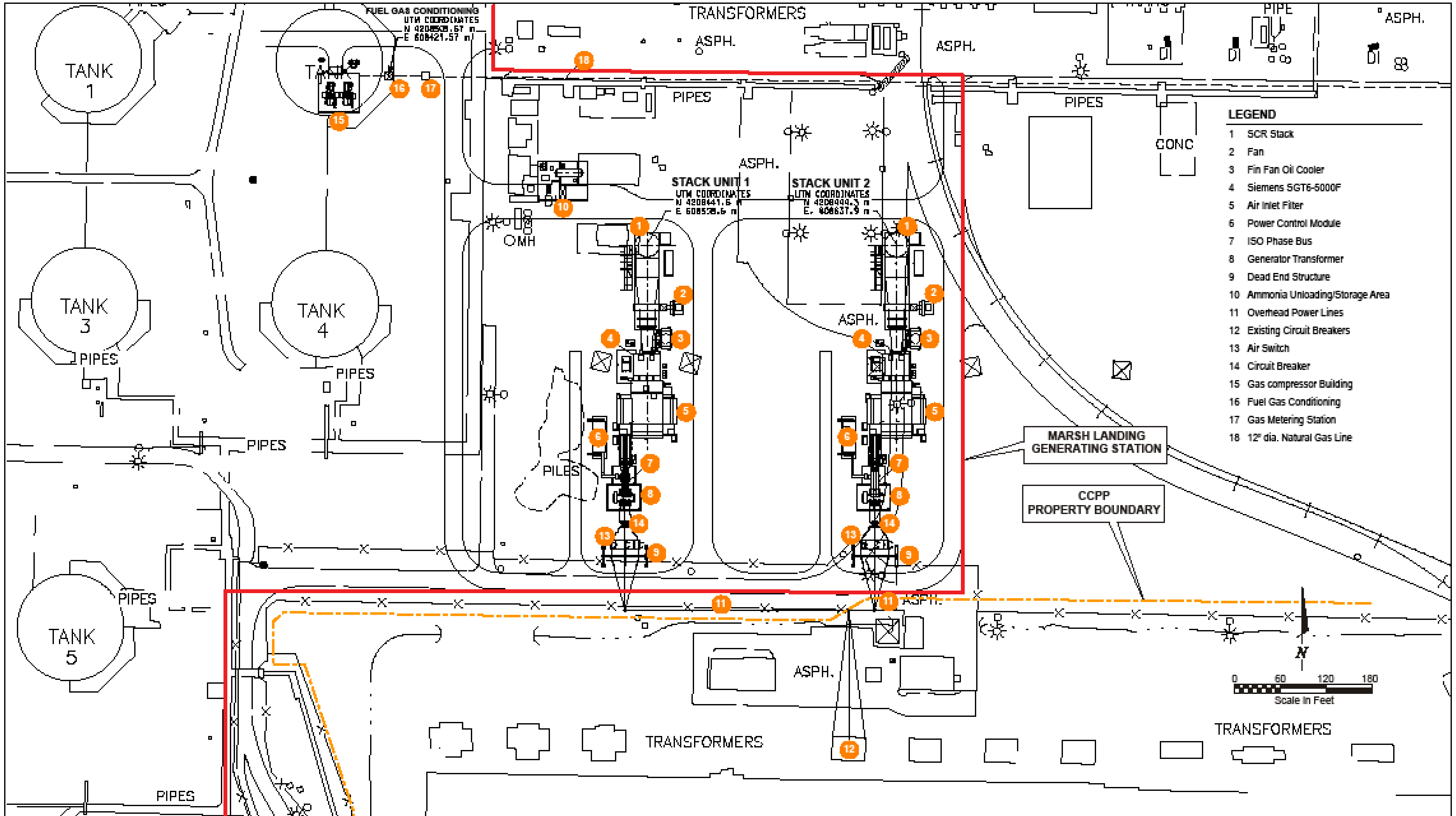
Marsh landing Generating Station Project



Source:
CH2MHill Lockwood Greene; General Arrangement Marsh Landing Generating Station,
Siemens Simple Cycle SGT6-5000F Equipment Layout;
Drawing No: MR-GA-ML-01-15 (Rev. D, 06/10/08)

PLOT PLAN – SIMPLE CYCLE UNITS
Marsh Landing Generating Station
Mirant Marsh Landing, LLC
Contra Costa County, California

June 2008
28067344

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FIGURE B-2

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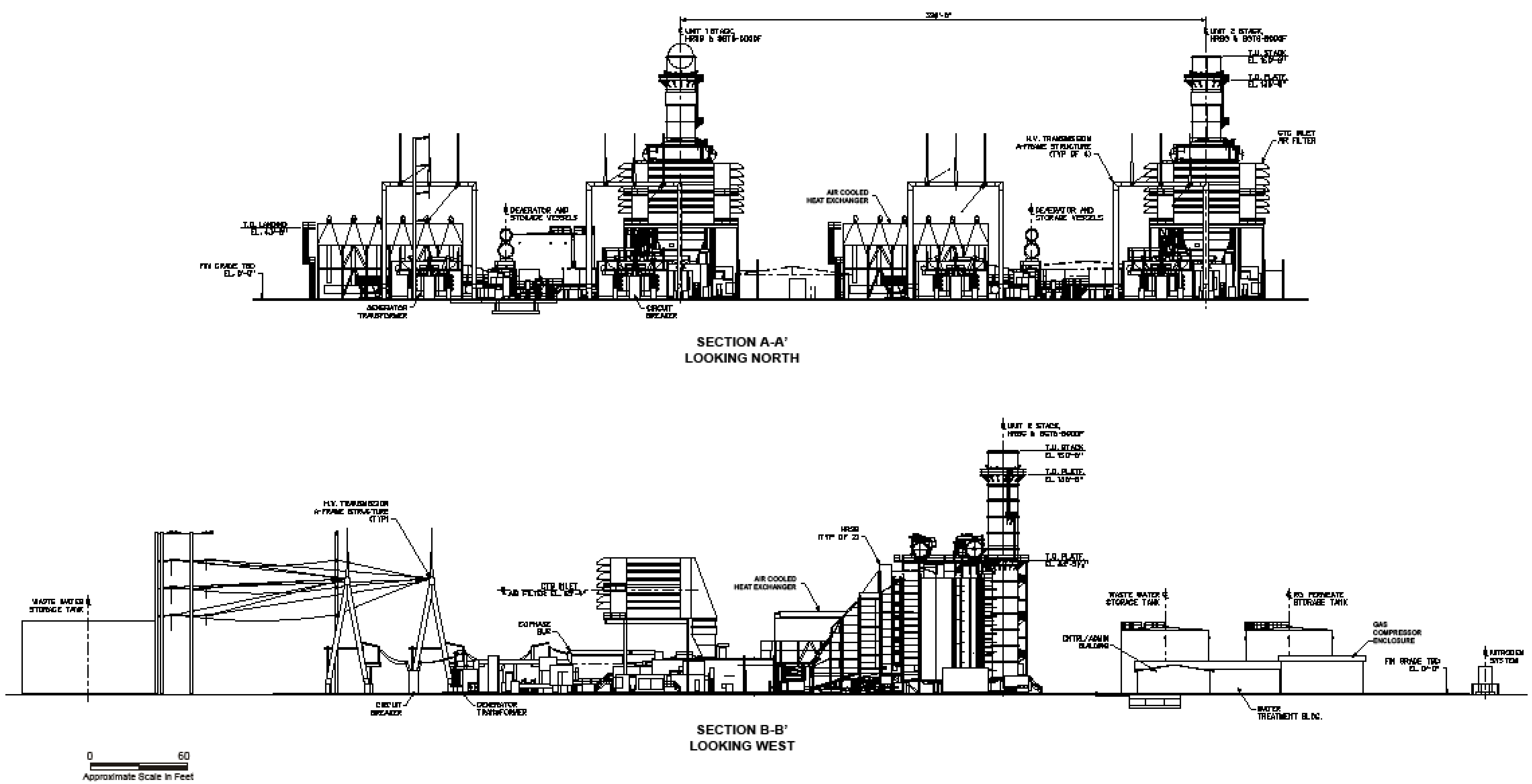
Appendix B Additional Plot Plan Figures

Marsh landing Generating Station Project



Source:
CH2MHill Lockwood Greene; General Arrangement, Marsh Landing Generating Station
Combined Cycle Siemens Flex 10s Elevation Views;
Drawing No: MR-GA-ML-01-16 (Rev. C, 4/22/08)

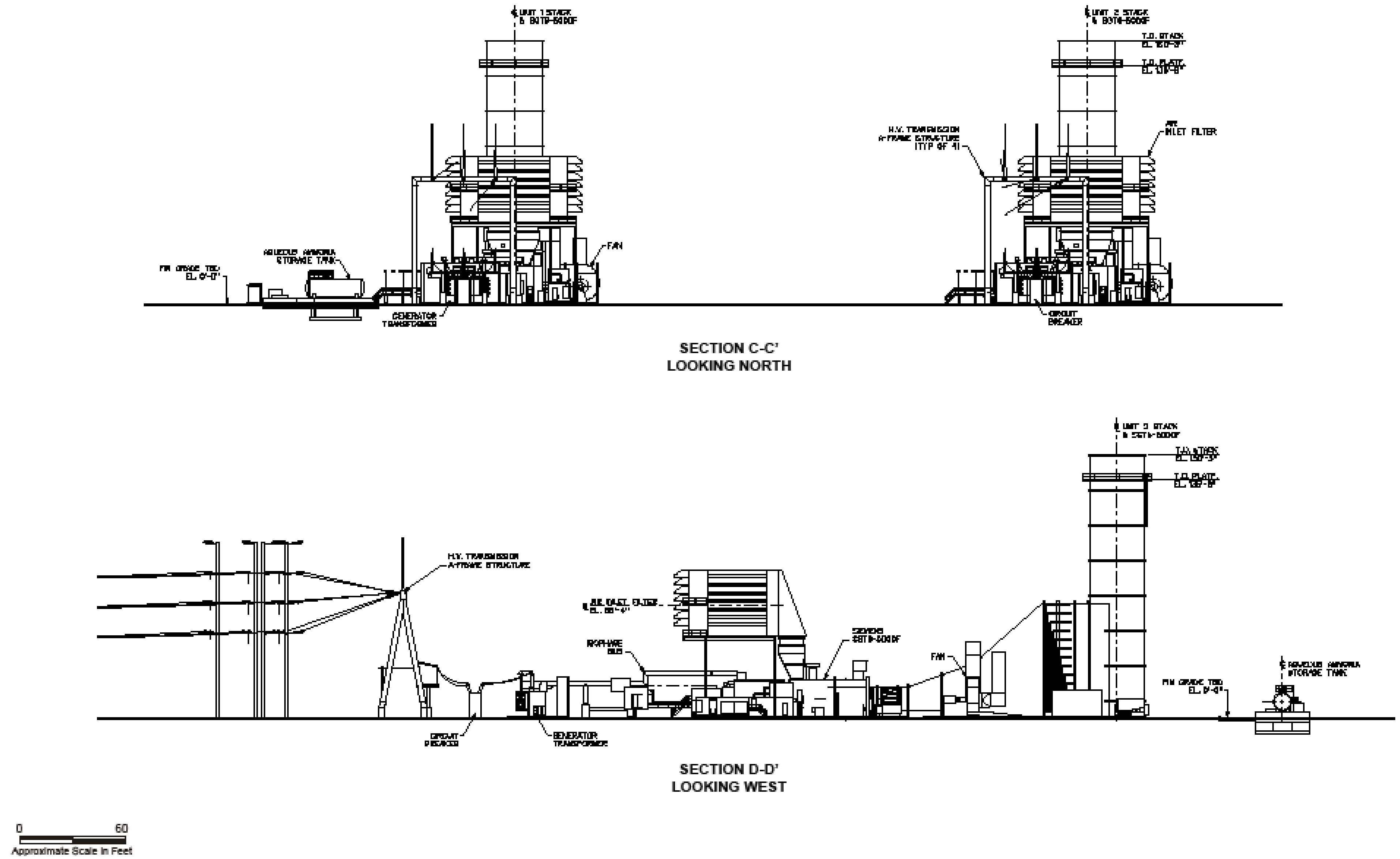
Note:
See Figure 2-1 for Section Locations.

ELEVATION VIEWS: FLEX PLANT 10

Marsh Landing Generating Station
Mirant Marsh Landing, LLC
Contra Costa County, California

June 2008
28067344

FIGURE B-3



Source:
CH2MHill Lockwood Greene; General Arrangement, Marsh Landing Generating Station
Siemens Simple Cycle SGT6-5000F Elevation Views;
Drawing No: MR-GA-ML-01-17 (Rev. C, 4/22/08)

Note:
See Figure 2-1 for Section Locations.

June 2008
28067344

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ELEVATION VIEWS:
SIMPLE CYCLES
Marsh Landing Generating Station
Mirant Marsh Landing, LLC
Contra Costa County, California

FIGURE B-4

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Appendix C. Emissions Calculations

Appendix C.1. 1 Demolition Equipment Exhaust Emissions

Marsh Landing Generating Station Project

	CO	CO_2	CH_4	N_2O	NO_x	PM_{10}	$PM_{2.5}$	SO_x	ROG[1]
Month	**Monthly Emissions (tons)**	**Monthly Emissions (tons)**	**Monthly Emissions (tons)**	**Monthly Emissions (tons)**	**Monthly Emissions (tons)**	**Monthly Emissions (tons)**	**Monthly Emissions (tons)**	**Monthly Emissions (tons)**	**Monthly Emissions (tons)**
June, 2009	2.61	83.02	0.01	0.01	0.70	0.03	0.02	0.00	0.16
July, 2009	2.65	100.47	0.01	0.01	0.88	0.03	0.03	0.00	0.17
August, 2009	2.65	100.47	0.01	0.01	0.88	0.03	0.03	0.00	0.17
September, 2009	2.65	100.47	0.01	0.01	0.88	0.03	0.03	0.00	0.17
October, 2009	2.65	100.47	0.01	0.01	0.88	0.03	0.03	0.00	0.17
November, 2009	2.61	83.02	0.01	0.01	0.70	0.03	0.02	0.00	0.16
Maximum (100 % load)	**2.65**	**100.47**	**0.0082**	**0.0071**	**0.88**	**0.033**	**0.0297**	**0.00110**	**0.1741**
Average (75 % load)	**1.99**	**75.35**	**0.0061**	**0.0053**	**0.66**	**0.024**	**0.0223**	**0.00082**	**0.1306**

Note:

[1] Assuming ROGs are equivalent to VOCs

- Assuming 75% operational average load

Appendix C.1.2 Construction Equipment Exhaust Emissions

Marsh Landing Generating Station Project

Month	CO		CO_2		CH_4		N_2O		NO_x		PM_{10}		$PM_{2.5}$		SO_x		ROG	
	Monthly Emissions (tons)	**12-Month Total (tons)**	**Monthly Emissions (tons)**	**12-Month Total (tons)**	**Monthly Emissions (tons)**	**12-Month Total (tons)**	**Monthly Emissions (tons)**	**12-Month Total (tons)**	**Monthly Emissions (tons)**	**12-Month Total (tons)**	**Monthly Emissions (tons)**	**12-Month Total (tons)**	**Monthly Emissions (tons)**	**12-Month Total (tons)**	**Monthly Emissions (tons)**	**12-Month Total (tons)**	**Monthly Emissions (tons)**	**12-Month Total (tons)**
October, 2009	1.23	NA	77.69	NA	0.01	NA	0.00	NA	0.77	NA	0.03	NA	0.03	NA	0.00	NA	0.11	NA
November, 2009	1.46	NA	82.67	NA	0.01	NA	0.00	NA	0.82	NA	0.03	NA	0.03	NA	0.00	NA	0.13	NA
December, 2009	2.53	NA	98.90	NA	0.01	NA	0.01	NA	0.99	NA	0.04	NA	0.04	NA	0.00	NA	0.19	NA
January, 2010	2.46	NA	76.28	NA	0.01	NA	0.01	NA	0.75	NA	0.03	NA	0.03	NA	0.00	NA	0.17	NA
February, 2010	2.93	NA	84.46	NA	0.01	NA	0.01	NA	0.84	NA	0.04	NA	0.03	NA	0.00	NA	0.18	NA
March, 2010	4.04	NA	112.06	NA	0.01	NA	0.01	NA	1.08	NA	0.04	NA	0.04	NA	0.00	NA	0.24	NA
April, 2010	3.41	NA	189.82	NA	0.01	NA	0.01	NA	1.83	NA	0.09	NA	0.09	NA	0.00	NA	0.36	NA
May, 2010	3.80	NA	91.50	NA	0.01	NA	0.01	NA	0.84	NA	0.03	NA	0.03	NA	0.00	NA	0.18	NA
June, 2010	2.90	NA	83.17	NA	0.01	NA	0.01	NA	0.77	NA	0.03	NA	0.03	NA	0.00	NA	0.15	NA
July, 2010	4.13	NA	99.64	NA	0.01	NA	0.01	NA	0.87	NA	0.03	NA	0.03	NA	0.00	NA	0.20	NA
August, 2010	3.68	NA	98.37	NA	0.01	NA	0.01	NA	0.86	NA	0.03	NA	0.03	NA	0.00	NA	0.19	NA
September, 2010	3.27	35.85	92.88	1,187.45	0.01	0.11	0.01	0.10	0.82	11.25	0.03	0.47	0.03	0.43	0.00	0.01	0.18	2.28
October, 2010	3.22	37.83	76.31	1,186.06	0.01	0.11	0.01	0.10	0.65	11.13	0.02	0.47	0.02	0.43	0.00	0.01	0.16	2.32
November, 2010	3.36	39.73	65.02	1,168.40	0.01	0.11	0.01	0.11	0.53	10.83	0.02	0.45	0.02	0.41	0.00	0.01	0.14	2.34
December, 2010	3.77	40.97	70.50	1,140.00	0.01	0.11	0.01	0.12	0.56	10.40	0.02	0.42	0.02	0.39	0.00	0.01	0.16	2.30
January, 2011	3.73	42.24	60.64	1,124.37	0.01	0.11	0.01	0.12	0.45	10.10	0.01	0.40	0.01	0.37	0.00	0.01	0.14	2.28
February, 2011	2.04	41.36	40.18	1,080.09	0.00	0.11	0.01	0.12	0.32	9.58	0.01	0.38	0.01	0.35	0.00	0.01	0.08	2.18
March, 2011	1.44	38.75	34.39	1,002.42	0.00	0.10	0.00	0.11	0.29	8.78	0.01	0.35	0.01	0.32	0.00	0.01	0.07	2.01
April, 2011	1.25	36.60	60.35	872.95	0.00	0.09	0.00	0.11	0.55	7.50	0.03	0.28	0.02	0.26	0.00	0.01	0.11	1.76
May, 2011	2.48	35.28	94.38	875.83	0.01	0.09	0.01	0.10	0.96	7.61	0.04	0.29	0.04	0.27	0.00	0.01	0.20	1.77
June, 2011	2.52	34.90	109.21	901.87	0.01	0.09	0.01	0.10	1.11	7.95	0.05	0.31	0.05	0.28	0.00	0.01	0.21	1.83
July, 2011	3.11	33.88	111.06	913.30	0.01	0.09	0.01	0.10	1.12	8.21	0.05	0.33	0.05	0.30	0.00	0.01	0.23	1.86
August, 2011	3.55	33.75	112.33	927.26	0.01	0.09	0.01	0.09	1.13	8.48	0.05	0.35	0.05	0.32	0.00	0.01	0.24	1.91
September, 2011	3.76	34.24	115.07	949.45	0.01	0.09	0.01	0.09	1.14	8.80	0.05	0.37	0.05	0.34	0.00	0.01	0.24	1.98
October, 2011	4.17	35.18	120.56	993.71	0.01	0.10	0.01	0.09	1.18	9.32	0.05	0.39	0.05	0.36	0.00	0.01	0.26	2.08
November, 2011	4.48	36.31	108.47	1,037.17	0.01	0.10	0.01	0.09	0.97	9.77	0.04	0.42	0.04	0.38	0.00	0.01	0.25	2.18
December, 2011	4.86	37.40	134.98	1,101.64	0.01	0.11	0.01	0.10	1.23	10.44	0.05	0.45	0.04	0.41	0.00	0.01	0.27	2.30
January, 2012	4.86	38.53	134.98	1,175.97	0.01	0.11	0.01	0.10	1.23	11.22	0.05	0.48	0.04	0.44	0.00	0.01	0.27	2.43
February, 2012	5.71	42.19	123.24	1,259.02	0.01	0.12	0.02	0.11	1.10	12.00	0.04	0.52	0.04	0.47	0.00	0.01	0.28	2.63
March, 2012	5.74	46.49	133.09	1,357.73	0.02	0.13	0.02	0.12	1.21	12.93	0.05	0.55	0.04	0.51	0.00	0.02	0.30	2.86
April, 2012	5.06	50.30	105.19	1,402.57	0.01	0.14	0.01	0.13	0.89	13.27	0.03	0.56	0.03	0.51	0.00	0.02	0.23	2.98
May, 2012	5.06	52.88	105.19	1,413.39	0.01	0.15	0.01	0.14	0.89	13.20	0.03	0.54	0.03	0.50	0.00	0.02	0.23	3.01
June, 2012	4.55	54.91	95.93	1,400.10	0.01	0.15	0.01	0.15	0.82	12.92	0.03	0.52	0.03	0.48	0.00	0.02	0.21	3.01
Maximum (100 % load)	**5.74**	**54.91**	**189.82**	**1,413.39**	**0.02**	**0.15**	**0.02**	**0.15**	**1.83**	**13.27**	**0.09**	**0.56**	**0.09**	**0.51**	**0.00**	**0.02**	**0.36**	**3.01**
Average	**3.70**	**39.98**	**98.76**	**1,112.31**	**0.01**	**0.11**	**0.01**	**0.11**	**0.90**	**10.26**	**0.04**	**0.42**	**0.03**	**0.39**	**0.00**	**0.01**	**0.20**	**2.29**
Average (75% load)	**3.09**	**31.68**	**142.36**	**890.58**	**0.01**	**0.08**	**0.01**	**0.09**	**1.37**	**8.43**	**0.07**	**0.35**	**0.06**	**0.32**	**0.00**	**0.01**	**0.27**	**1.75**

Note:

[1] Assuming ROGs are equivalent to VOCs

- Assuming 75% operational average load

Maximum Total Emissions from Construction and Demolition

	CO	CO_2	CH_4	N_2O	NO_x	PM_{10}	$PM_{2.5}$	SO_x	ROG
Monthly Emissions (tons)	6.65	199.37	0.019	0.017	1.87	0.0942	0.0857	0.00220	0.3972
12-Month Total (tons)	54.91	1,755.36	0.156	0.145	16.18	0.6547	0.599	0.0193	3.292

Appendix C.2.1 Operational Emissions (Siemens Combined Cycle FP 10 Unit)

Turbine Operating Parameters

Ambient Temperature	UNITS	Winter Minimum (20°F / 90% RH)			Yearly Average (59°)			Summer Maximum (94°F)					
CTG Load Level	%	**100%**	**85%**	**60%**	**100%**	**85%**	**60%**	**100%**	**100%**	**100%**	**100%**	**85%**	**60%**
Case No From Siemens Data		**1**	**2**	**39**	**4**	**8**	**60**	**19**	**18**	**17**	**16**		**43**
Evap Cooling Status	off / on	**Off**	**Off**	**Off**	**Off**	**Off**	**Off**	**On**	**On**	**Off**	**Off**	**Off**	**Off**
Power Augmentation Status	off / on	**Off**	**Off**	**Off**	**Off**	**Off**	**Off**	**On**	**Off**	**On**	**Off**	**Off**	**Off**
Stack Outlet Temperature	(°F)	**350**	**346**	**343.7**	**340**	**337**	**328.7**	**338**	**348**	**333**	**341**	**346**	**323.3**

Average Emission Rates from each Gas Turbine (lbs/hr/turbine) - Normal Operation

	UNITS	Winter Minimum (20°F / 90% RH)			Yearly Average (59°)			Summer Maximum (94°F)					
Net Power	kw	**286,700**	**244,200**	**172,900**	**259,400**	**221,400**	**149,600**	**268,700**	**250,100**	**255,900**	**233,300**	**N/A**	**140,100.0**
Heat Rate,	Btu/kWh (LHV)	**7,135**	**7,330**	**8,250**	**7,160**	**7,410**	**8,455**	**7,115**	**7,130**	**7,020**	**7,185**	**N/A**	**8,580.0**
Fuel Flow	MMBtu/hr (LHV)	2,046	1,790	1,426	1,857	1,641	1,265	1,912	1,783	1,796	1,676	1,509	1,202
Fuel Flow	MMBtu/hr (HHV)	2,271	1,987	1,583	2,062	1,821	1,404	2,122	1,979	1,994	1,861	1,674.6	1,334
Fuel Heating Value	Btu/scf	**908**	**908**	**908**	**908**	**908**	**908**	**908**	**908**	**908**	**908**	**908.0**	**908.0**
Oxygen	VOL%	**12.3**	**12.4**	**12.8**	**12.3**	**12.5**	**12.7**	**10.9**	**12.0**	**11.1**	**12.3**		**12.8**
CO_2	VOL%	**4.0**	**3.9**	**3.8**	**3.9**	**3.8**	**3.7**	**4.0**	**3.9**	**3.9**	**3.8**		**3.6**
H_2O	VOL%	**8.0**	**7.9**	**7.6**	**8.5**	**8.4**	**8.6**	**14.9**	**9.9**	**14.1**	**9.1**		**8.7**
N_2	VOL%	**74.9**	**74.9**	**75.0**	**74.4**	**74.4**	**74.1**	**69.4**	**73.3**	**70.0**	**73.9**		**74.1**
Ar	VOL%	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**0.8**	**0.9**	**0.8**	**0.9**		**0.9**
Oxygen	lbm/hr	604,147.8	534,359.7	448,054.1	557,810.4	502,428.7	409,093.5	501,141.7	525,617.5	487,406.3	510,555.9	459,500.3	530,349.7
CO_2	lbm/hr	267,228.7	232,086.9	182,164.7	242,994.2	213,078.2	161,725.3	250,167.8	233,504.7	170,789.3	159,522.8	143,570.5	150,639.2
H_2O	lbm/hr	220,485.3	191,262.8	149,961.9	217,605.1	191,070.1	155,590.9	386,375.4	242,824.1	617,906.9	378,451.1	340,606.0	359,376.2
N_2	lbm/hr	3,215,827.9	2,822,939.8	2,307,879.6	2,950,136.9	2,629,121.3	2,085,751.8	2,799,994.9	2,801,704.9	3,066,324.5	3,069,151.4	2,762,236.2	3,073,372.2
Ar	lbm/hr	54,528.1	48,378.2	38,605.4	50,345.8	44,837.4	34,902.7	47,726.0	47,959.1	36,785.4	36,557.3	32,901.6	36,103.6
MW of exhaust gas	lb/lbmol	**28.5**	**28.5**	**28.5**	**28.4**	**28.4**	**28.4**	**27.7**	**28.2**	**27.8**	**28.3**	**28.3**	**28.3**
NO_x (@ 2.0 ppm)	lbm/hr	**17.4**	**15.1**	**12.0**	**15.8**	**13.9**	**10.0**	**16.3**	**15.2**	**15.3**	**14.3**	**12.9**	**10.0**
CO (@ 2.0 ppm)	lbm/hr	**10.6**	**9.2**	**7.1**	**9.7**	**8.5**	**6.3**	**10.0**	**9.3**	**9.4**	**8.7**	**7.8**	**6.0**
CO (@ 3 ppm)	lbm/hr	15.9	13.8	10.7	14.6	12.8	9.5	15.0	14.0	14.1	13.1	11.7	9.0
VOC (@ 2.0 ppm)	lbm/hr	**6.2**	**5.4**	**4.1**	**5.6**	**5.0**	**3.6**	**5.8**	**5.4**	**5.4**	**5.0**	**4.5**	**3.5**
SO_2 (based on 0.4 gr total S / 100 scf)	lbm/hr	2.6	2.3	1.8	2.3	2.1	1.6	2.4	2.2	2.3	2.1	1.9	1.5
SO_2 (based on 1.0 gr total S / 100 scf) worst-case	lbm/hr	6.4	5.6	4.5	5.8	5.2	4.0	6.0	5.6	5.6	5.3	4.7	3.8
PM_{10}	lbm/hr	**10.0**	**8.9**	**8.0**	**9.3**	**8.3**	**8.0**	**8.9**	**8.8**	**8.5**	**8.5**	**7.7**	**8.0**
NH_3 (@ 5 ppm slip)	lbm/hr	**16.1**	**14.0**	**11.0**	**14.7**	**12.8**	**10.0**	**15.1**	**14.1**	**14.2**	**13.2**	**11.9**	**9.0**
% of HC as VOC (using CO @ 3ppm)	%	28.1	28.1	27.8	27.8	28.2	27.6	27.9	27.9	27.7	27.7	27.7	28.0
Total Inerts	lbm/hr	4,363,324	3,828,197	3,129,789	4,018,750	3,580,309	2,847,064	3,985,700	3,851,272	3,800,335	3,675,203	3,307,683	2,731,651
Total	lbm/hr	**4,363,392**	**3,828,256**	**3,129,837**	**4,018,812**	**3,580,364**	**2,847,107**	**3,985,764**	**3,851,332**	**3,800,395**	**3,675,259**	**3,307,733**	**2,731,692**
Total Inerts	lbmol/hr	153,368	134,559	109,817	141,605	126,112	100,426	143,940	136,425	136,850	129,820	116,838	96,389
Total Inerts	ft^3/min	1,511,297	1,319,398	1,073,724	1,378,149	1,222,758	963,566	1,397,371	1,341,016	1,320,217	1,265,033	1,145,639	918,497
Exit Velocity	fps	70.5	61.5	50.1	64.3	57.0	44.9	65.2	62.5	61.6	59.0	53.4	42.8

notes:

All turbine operating parameters and emissions data provided by Siemens based on expected operating parameters at the Contra Costa Site

Assumed average sulfur content in gas (for annual emission): 0.4 gr total S / 100 scf

Assumed average sulfur content in gas (for short term emissions): 1 gr total S / 100 scf

Assumed fuel heating value: 908 Btu/scf

HHV/LHV 1.11 ratio

Stack Diameter 21.33 ft

Startup / Shutdown Emissions from Turbine (1CT)

Startup (41° F)			Shutdown (41° F)		
12 (min. in startup)	1-hr. (w/1 SU) (lb/hr)	SU emissions (lb/12min)	7 (min. in shutdown)	1-hr. (w/1 SD) (lb/hr)	SD emissions (lb/7min)
NO_X	38.7	24.8	NOx	25.9	10.5
CO	279.8	267.1	CO	149.5	135.4
VOC	17.7	12.7	VOC	10.7	5.2
SO_2 (based on 0.4 gr total S / 100 scf)	2.7	0.6	SO_2	2.4	0.2
SO_2 (based on 1.0 gr total S / 100 scf) worst-case	6.7	1.6	SO_2 worst - case	6.1	0.4
PM_{10}	11.1	3.1	PM_{10}	9.9	1.1

notes:

Startup and shutdown emissions data provided by Siemens based on expected operating parameters at the Contra Costa Site

Startup and shutdown SO_2 emissions are calculated based on the total amount of fuel used for each and the emission rate of SO_2 at winter minimum - 20°F; 100% load

Fuel use for startup on natural gas @ 41 °F 24,173 lb/start

Fuel use for shutdown on natural gas @ 41 °F 6,525 lb/shutdown

Average Annual Emissions

		Pollutant	Turbine Emissions (lb/yr/CT)	Emissions for Both Turbines (ton/yr/2CT)
Total Hours of Operation	4,383			
Total Number of Starts	193	NO_X	77,103	77.1
Start Duration (hr)	0.2	CO	142,371	142.4
Total Number of Shutdowns	193	CO_2	1,093,738,123	1,093,738
Shutdown Duration (hr)	0.1	VOC	28,459	28.5
Yearly Average w/Power Augmentation Operation (hr)	4000	SO_2	10,521	10.5
Normal Operation (hr)	322	PM_{10}	39,400	39.4

notes:

Average annual emissions are calculated using yearly average- 59°F, at 100 % load for Normal Operation

Power augmentation emissions are calculated using summer maximum - 94°F, at 100 % load with power augmentation and evaporative cooling ON.

SO_2 emissions are based on 0.4 gr total S / 100 scf.

Appendix C.2.1 Operational Emissions (Siemens Combined Cycle FP 10 Unit)

Modeling Worst-Case 3 hr Emissions per Turbine

SO_2 worst-case 3 hr emissions per turbine	20.1	lb/3 hr
SO_2 worst-case 1 hr emissions per turbine	6.7	lb/hr
SO_2 modeling worst-case emissions per turbine	0.8	g/sec

notes:

Only SO_2 is considered for an average 3-hour Ambient Air Quality Standard.

Operational emissions using "worst-case" (winter minimum - 20°F; 100% load). SO2 emissions are based on 1 gr/100 scf

Worst-case 3 hr emissions conservatively assumes 3 startups in a 3 hr period, no shut downs

Modeling Worst-Case 8 hr Emissions per Turbine

CO worst-case 8 hr emissions per turbine	788.6	lb/8 hr
	98.6	lb/hr
	12.4	g/sec

notes:

Only CO is considered for an average 8-hour Ambient Air Quality Standard.

Operational emissions using "worst-case" (winter minimum - 20°F; 100% load)

Worst-case 8 hr emissions assumes a total of 2 start up periods and 1 shutdown

Worst-Case Daily Emissions per Turbine

Pollutant	Time in Start Up (hr)	Time in Shut Down (hr)	Time in Operation (hr)	Worst-Case Daily Emissions (lb/day/CT)	Modeling Worst-Case 24 Hr Emission (g/s/CT)
NOx	0.6	0.4	23.1	507.0	
CO	0.6	0.4	23.1	1,574.1	
VOC	0.6	0.4	23.1	196.6	
SO_2	0.6	0.4	23.1	154.2	0.8
PM_{10}	0.6	0.4	23.1	243.0	1.3

Assumptions:
For NOx, CO, VOC, SO_2 and PM_{10} -- emissions are calculated assuming 3 startup periods, 3 shut down periods, and remainder of time is spent in operation at "worst-case" (winter minimum - 20°F; 100% load)

Appendix C.2.2 Operational Emissions (Simple Cycle Unit)

Turbine Operating Parameters

Ambient Temperature	**UNITS**	**Winter Minimum (20°F / 90%RH)**			**Yearly Average (60°F / 64% RH)**			**Summer Maximum (94°F)**		
CTG Load Level	%	**100%**	**75%**	**60%**	**100%**	**75%**	**60%**	**100%**	**75%**	**60%**
Evap Cooling Status	On / Off	Off	Off	Off	85%	OFF	OFF	On	Off	Off
Gas Turbine Outlet Temperature	ºF	1,065	1,065	1,065	1,090	1,090	1,091	1,123	1,123	1,122
Stack Outlet Temperature	ºF	750	750	750	750	750	750	750	750	750
Dilution Air Inlet Temperature	ºF	25	25	25	64	64	64	99	99	99
Dilution Air Flow Rate	lbm/hr	1,971,557	1,601,991	1,416,082	2,071,246	1,718,357	1,525,648	2,189,638	1,842,995	1,630,352
Dilution Air Flow Rate	lbmol/hr	68,079	55,317	48,898	71,521	59,336	52,681	75,609	63,639	56,297

Average Emission Rates from each Gas Turbine (lbs/hr/turbine) - Normal Operation

(Reference: Siemens Turbine/Site Specific Information)	**UNITS**	**Winter Minimum (20°F / 90%RH)**			**Yearly Average (60°F / 64% RH)**			**Summer Maximum (94°F)**		
Heat Input, LHV	MMBtu/hr	1,984	1,565	1,333	1,800	1,441	1,229	1,624	1,315	1,125
Fuel Heating Value, LHV	Btu/lb	20,670	20,670	20,670	20,670	20,670	20,670	20,670	20,670	20,670
Fuel Heating Value, LHV	Btu/scf	912	912	912	912	912	912	912	912	912
Fuel Flow, LHV	scf/hr	2,174,637	1,715,376	1,461,084	1,972,957	1,579,461	1,347,091	1,780,045	1,441,354	1,233,098
Exhaust Flow	lbm/hr/turbine	4,366,477	3,547,986	3,136,246	4,021,343	3,336,206	2,953,373	3,677,383	3,095,213	2,745,451
O_2	vol%	12.54	12.77	13.06	12.54	12.82	13.1	12.52	12.82	13.09
CO_2	vol%	3.86	3.75	3.62	3.79	3.66	3.54	3.74	3.6	3.47
H_2O	vol%	7.77	7.56	7.3	8.32	8.07	7.82	8.9	8.63	8.4
N_2	vol%	74.93	75.02	75.12	74.45	74.55	74.65	73.96	74.06	74.15
Ar	vol%	0.9	0.9	0.9	0.89	0.89	0.89	0.88	0.89	0.89
O_2	lbm/hr	1,072,080	880,116	787,879	1,047,892	879,547	788,662	1,026,953	874,706	782,932
CO_2	lbm/hr	260,577	205,783	175,316	236,053	189,163	161,845	213,656	173,022	147,980
H_2O	lbm/hr	214,831	169,594	144,895	212,327	170,814	146,487	208,140	169,927	146,607
N_2	lbm/hr	4,710,183	3,829,038	3,386,564	4,519,319	3,751,341	2,172,501	4,344,348	3,658,137	3,243,100
Ar	lbm/hr	80,254	65,210	57,643	76,779	63,698	56,445	73,627	62,280	55,187
NO_x as NO2 (@ 2.0 ppm)	lbm/hr	16.67	13.11	11.11	15.11	12.00	10.22	13.56	11.11	9.33
NO_x as NO2 (@ 2.5 ppm)	lbm/hr	20.83	16.39	13.89	18.89	15.00	12.78	16.94	13.89	11.67
CO (@ 3.0 ppm)	lbm/hr	15.00	12.00	10.20	13.50	11.25	9.30	12.75	9.75	8.70
VOC (@ 2.0 ppm)	lbm/hr	5.80	4.60	3.87	5.20	4.20	3.60	4.80	3.80	3.27
SO_2 (using 0.4 gr/100scf)	lbm/hr	2.48	1.96	1.67	2.25	1.80	1.54	2.03	1.65	1.41
SO_2 (using 1 gr/100scf)	lbm/hr	6.21	4.90	4.17	5.63	4.51	3.84	5.08	4.11	3.52
PM_{10}	lbm/hr	9	8	8	8	8	8	8	8	8
NH_3 (@ 5 ppm slip)	lbm/hr	16.46	13.36	11.80	15.23	12.62	6.84	13.99	11.77	10.43
NH_3 (@ 10 ppm slip)	lbm/hr	32.91	26.73	23.61	30.46	25.24	13.69	27.99	23.54	20.86
% of HC as VOC (CO@3 ppm)	%	38.67	38.33	37.91	38.52	37.33	38.71	37.65	38.97	37.55
Total Inerts (Flue Gas + Dilution Air)	lbm/hr	6,337,924	5,149,741	4,552,297	6,092,370	5,054,562	3,325,941	5,866,723	4,938,073	4,375,806
Stack Gas MW	lb/lbmol	28.46	28.47	28.49	28.39	28.41	28.43	28.33	28.34	28.36
Total Inerts	lbmol/hr	222,696	180,883	159,786	214,596	177,915	116,987	207,085	174,244	154,295
Total	ft^3/min	3,278,539	2,662,970	2,352,374	3,159,287	2,619,272	1,722,288	3,048,718	2,565,228	2,271,538
Exit Velocity	fps	70.9	57.6	50.8	68.3	56.6	37.2	65.9	55.4	49.1

notes:

All turbine operating parameters and emissions data provided by CH2M Hill based on expected operating parameters at the Contra Costa Site

Assumed average sulfur content in gas (for annual emission):	0.4	gr total S / 100 scf	Assumed fuel heating value:	1,015	Btu/scf	hhv/lhv ratio:	1.11	ratio
Assumed average sulfur content in gas (for short term emissions):	1	gr total S / 100 scf	Stack Diameter:	31.333	ft			

Startup / Shutdown Emissions from Turbine (1CT)

Startup (41° F)			Shutdown (41° F)		
11 (min. in startup)	**Max 1-hr. (lb/hr)**	**Total (lb/ 11 min)**	**6 (min. in shutdown)**	**Max 1-hr. (lb/hr)**	**Total (lb/ 6 min)**
NO_X (2.5 ppm)	29.0	12	**NOx**	28.8	10
CO (3 ppm)	225.25	213	**CO**	124	110
VOC (2 ppm)	15.7	11	**VOC**	10.2	5
SO_2 (based on 0.4 gr total S / 100 scf)	2.19	0.17	**SO_2**	2.4	0.15
SO_2 (based on 1.0 gr total S / 100 scf) worst-case	5.49	0.42	**SO_2** worst - case	5.7	0.37
PM_{10}	8.4	1	**PM_{10}**	9.1	1

notes:

Estimated Startup data are from CTG ignition through 100% CTG load.

Startup and Shutdown Emissions for NOx, CO, VOC and PM10 from data provided by Siemens based on 59°F ambient temperature.
NOx emissions assume SCR is not in operation (no removal); CO and VOC emissions assume CatOx is not in operation (no removal); SO_2 emissions assume complete conversion of all sulfur to SO_2.

Average Annual Emissions

		Pollutant	Turbine Emissions (lb/yr/CT)	Emissions for Both Turbines (ton/yr/2CT)
Total Hours of Operation	877			
Total Number of Cold Starts	100	NO_X	18,230.4	18.2
Cold Start Duration (hr)	0.18	CO	43,757.0	43.8
		CO_2	207,018,335.5	207,018
Total Number of Shutdowns	100	VOC	6,013.1	6.0
Shutdown Duration (hr)	0.10	SO_2	1,943.3	1.9
Average Operation (hr)	849	PM_{10}	6,989.3	7.0

notes:

Average annual emissions are calculated using yearly average- 59°F, at 100 % load.

SO_2 emissions are based on 0.4 gr total S / 100 scf.

Appendix C.2.2 Operational Emissions (Simple Cycle Unit)

Marsh Landing Generating Station Project

Worst-Case 1 hr Emissions per Turbine	lb/hr	g/sec
NOx	29.0	3.66
CO	225.3	28.38
SO_2	6.2	0.78
PM_{10}	9.1	1.15

notes:

SO_2 emissions are based on 1 gr/100 scf

Worst-Case 3 hr Emissions per Turbine	lb/3-hrs	g/sec
SO_2 (based on 1 gr total S/100 scf)	18.6	0.78

notes:

Only SO_2 is considered for a 3-hour average Ambient Air Quality Standard.

assumes no start ups or shut downs, only operational emissions from "worse-case" (winter minimum - 20°F; 100% load)

Worst-Case 8 hr Emissions per Turbine	lb/8hr	g/sec
CO (3ppm)	967.8	15.24

notes:

Only CO is considered for an 8-hour average Ambient Air Quality Standard.

Worst-case daily emissions assumes a total start up of :	3
Worst-case daily emissions assumes a total shut down of :	2

Remainder of time is spent at "worst-case" (winter minimum - 20°F; 100% load).

Worst-Case 24 hr Emissions per Turbine	lb/24hr	g/sec
NOx	540.4	2.84
CO	1207.8	6.34
VOC	177.9	0.93
SO_2	58.5	0.31
SO_2	146.3	0.77
PM_{10}	214.3	1.12

notes:

Worst-case daily emissions assumes a total start up of :	3
Worst-case daily emissions assumes a total shut down of :	2

Remainder of time is spent at "worst case" (winter minimum - 20°F; 100% load)

Maximum Annual Emissions

Annual	Turbine Emissions (lb/yr/CT)	Emissions for Both Turbines (ton/yr/2CT)
NO_X	19,881	19.9
CO	45,030	45.0
VOC	6,522	6.52
SO_2 (based on 0.4 gr total S / 100 scf)	2,139	2.14
PM_{10}	7,838	7.84

Appendix C.2.3 Process Heaters

Marsh Landing Generating Station Project

	Emission Factors		Emission Rate
	lbs/MCF/unit	lbs/MMBTU/unit	lbs/hr/unit
CO	35	**0.034**	0.17
NO_x	30.6	**0.03**	0.15
PM_{10}	3	**0.0029**	0.015
SO_2 (0.4 gr S/100 SCF)	1.14	**0.0011**	0.006
SO_2 (1gr S/100 SCF)	2.85	**0.0028**	0.014
VOC	2.8	**0.0027**	0.014

note: these emission factors are from FIRE ver 6.25. Using "process heaters from natural gas" (SCC 3-10-004-04). The SCC# was obtained from http://www.epa.gov/ttnchie1/eiip/techreport/volume02/ii10.pdf.
Except for Sox, which was calculated.

1020	BTU/SCF	conversion factor
5	MMBTU/hr	max heat input capacity

For Marsh Landing

2	units	number of preheaters, one for FP10, one for SSC6-5000F
4,383	hours	number of hours FP10 is running
877	hours	number of hours SSC6-5000F is running

Modeling Worst-Case 1 hr Emissions per unit (same for both units)

pollutant	lbs/hr/unit	g/sec/unit
CO	0.172	0.0216
NO_x	0.150	0.0189
PM_{10}	0.015	0.0019
SO_2 (1gr S/100 SCF)	0.014	0.0018
VOC	0.014	0.0017

Appendix C.2. 4 Total Operational

Marsh Landing Generating Station Project

Pollutant	Total Marsh Landing Turbines Potential Emissions (ton/yr)	PSD Threshold (ton/yr)	Exceed PSD Threshold	Amount of Exceedance (ton/yr)	New Source Review Offset Ratio	Offsets Required (ton/yr)
NO_X	95.7	40	Yes	55.7	1.15	110.0
CO	186.5	100	Yes	86.5	0	0.0
CO_2	1,300,756.5					
VOC	34.5	40	No	0.0	1.15	39.7
SO_2	12.5	40	No	0.0	1	12.5
PM_{10}	46.4	15	Yes	31.4	1	46.4

assumptions:

Includes emissions from (2) Siemens Flex Plant 10 Turbines and (2) Siemans SSC6 Simple Cycle Combustion Turbines

Offset ratios are 1.15 : 1 for NOx and VOC emissions on a pollutant specific basis, for each pollutant (facility wide) over 35 tons per year. Below 35 tons is 1 : 1.

Offset ratios are 1 : 1 for remaining criteria pollutants.

Ave. Annual Emissions	Emissions from Both Combined Cycle Units	Emissions from Both Simple Cycle Units	S-5 emissions	S-6 emissions	TOTAL
	ton/yr/2CT	ton/yr/2CT	ton/yr/2CT	ton/yr/2CT	tons/yr
NO_X	77.10	18.23	0.329	0.066	95.66
CO	142.37	43.76	0.376	0.075	186.50
CO_2	1,093,738	207,018	---	---	1,300,756.46
VOC	28.46	6.01	0.030	0.006	34.50
SO_2 (based on 0.4 gr total S / 100 scf)	10.52	1.94	0.012	0.002	12.48
PM_{10}	39.40	6.99	0.032	0.006	46.42

Appendix D. Application Forms

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street, San Francisco, CA 94109
Engineering Division (415) 749-4990
www.baaqmd.gov fax (415) 749-5030

Form P-101B

Authority to Construct/
Permit to Operate

1. Application Information

BAAQMD Plant No. ________ Company Name Mirant Marsh Landing, LLC

Equipment/Project Description Marsh Landing Generating Station Project

2. Plant Information *If you have not previously been assigned a Plant Number by the District or if you want to update any plant data that you have previously supplied to the District, please complete this section.*

Equipment Location: The MLGS will be located within the existing CCPP site, Assessor's Parcel Number (APN) 051 031 014, in unincorporated Contra Costa County, California, Sections 16, Township 2 North, Range 2 East, on the U.SGS Antioch North Topographic Quadrangle Map

City: Antioch Zip Code: ________

Mail Address: P.O. Box 192,696 W.10th Street

City: Pittsburg State: CA Zip Code: 94565

Plant Contact: Ronald Kino Title: Manager EHS

Telephone: (925) 427-3567 Fax: (925) 427-3535 Email: Ronald.kino@mirant.com

NAICS (North American Industry Classification System) see www.census.gov/epcd/naics02/naico602.htm ________

3. Proximity to a School (K-12)

The sources in this permit application (*check one*) ☐ Are ☒ Are not within 1,000 ft of the outer boundary of the nearest school.

4. Application Contact Information *All correspondence from the District regarding this application will be sent to the plant contact unless you wish to designate a different contact for this application.*

Application Contact: Mark Strehlow Title: Leader, Air Quality and Public Health

Mail Address: 1333 Broadway Suite 800

City: Oakland State: CA Zip Code: 94612

Telephone: (510)836-3600 Fax: (510)874-3268 Email: mark_strehlow@urscorp.com

5. Additional Information *The following additional information is required for all permit applications and should be included with your submittal. Failure to provide this information may delay the review of your application. Please indicate that each item has been addressed by checking the box. Contact the Engineering Division if you need assistance.*

☒ If a new Plant, a local street map showing the location of your business

☒ A facility map, drawn roughly to scale, that locates the equipment and its emission points

☒ Completed data form(s) and a pollutant flow diagram for each piece of equipment. (See www.baaqmd.gov/pmt/forms/)

☐ Project/equipment description, manufacturer's data

☒ Discussion and/or calculations of the emissions of air pollutants from the equipment

6. Trade Secrets *Under the California Public Records Act, all information in your permit application will be considered a matter of public record and may be disclosed to a third party. If you wish to keep certain items separate as specified in Regulation 2, Rule 1, Section 202.7, please complete the following steps.*

☐ Each page containing trade secret information must be labeled "trade secret" with the trade secret information clearly marked.

☐ A second copy, with trade secret information blanked out, marked "public copy" must be provided.

☐ For each item asserted to be trade secret, you must provide a statement which provides the basis for your claim.

7. Small Business Certification *You are entitled to a reduced permit fee if you qualify as a small business as defined in Regulation 3. In order to qualify, you must certify that your business meets all of the following criteria:*

- ☐ The business does not employ more than 10 persons and its gross annual income does not exceed $600,000.
- ☐ And the business is not an affiliate of a non-small business. (Note: a non-small business employs more than 10 persons and/or its gross income exceeds $600,000.)

8. Accelerated Permitting *The Accelerated Permitting Program entitles you to install and operate qualifying sources of air pollution and abatement equipment* ***without waiting for the District to issue a Permit to Operate****. To participate in this program you must certify that your project will meet all of the following criteria. Please acknowledge each item by checking each box.*

- ☐ Uncontrolled emissions of any single pollutant are each less than 10 lb/highest day, or the equipment has been precertified by the BAAQMD.
- ☐ Emissions of toxic compounds do not exceed the trigger levels identified in Table 2-5-1 (see Regulation 2, Rule 5).
- ☐ The project is not subject to public notice requirements (the source is either more than 1000 ft. from the nearest school, or the source does not emit any toxic compound in Table 2-5-1).
- ☐ For replacement of abatement equipment, the new equipment must have an equal or greater overall abatement efficiency for all pollutants than the equipment being replaced.
- ☐ For alterations of existing sources, for all pollutants the alteration does not result in an increase in emissions.
- ☐ Payment of applicable fees (the minimum permit fee to install and operate each source). See Regulation 3 or contact the Engineering Division for help in determining your fees.

9. CEQA *Please answer the following questions pertaining to CEQA (California Environmental Quality Act).*

A. Has another public agency prepared, required preparation of, or issued a notice regarding preparation of a California Environmental Quality Act (CEQA) document (initial study, negative declaration, environmental impact report, or other CEQA document) that analyzes impacts of this project or another project of which it is a part or to which it is related? ☐YES ☒NO If no, go to section 9B.

Describe the document or notice, preparer, and date of document or expected date of completion:

B. List and describe any other permits or agency approvals required for this project by city, regional, state or federal agencies:

California Energy Commission

C. List and describe all other prior or current projects for which either of the following statements is true: (1) the project that is the subject of this application could not be undertaken without the project listed below, (2) the project listed below could not be undertaken without the project that is the subject of this application:

10. Certification *I hereby certify that all information contained herein is true and correct. (Please sign and date this form)*

Mark Strehlow	Leader, Air Quality and Public Health		June 24, 2008
Name of person certifying (print)	Title of person certifying	Signature of person certifying	Date

Send all application materials to the **BAAQMD Engineering Division, 939 Ellis Street, San Francisco, CA 94109.**

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . fax (415) 749-5030
Website: www.baaqmd.gov

Data Form C
FUEL COMBUSTION SOURCE

(for District use only)

New ☐ Modified ☐ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

1. Company Name: Mirant Marsh Landing, LLC Plant No: (If unknown, leave blank) Source No. S-1

2. Equipment Name & Number, or Description: Natural Gas-Fired CTG #1

3. Make, Model : Siemens FP10 Natural Gas-Fired CTG Maximum firing rate: 2271MM Btu/hr

4. Date of modification or initial operation: ________________ *(if unknown, leave blank)*

5. Primary use (check one): ☒ electrical generation ☐ space heat ☐ waste disposal ☐ testing ☐ abatement device ☐ cogeneration ☐ resource recovery ☐ other ☐ process heat; material heated ____________________

6. SIC Number____________ (If unknown leave blank)

7. Equipment type (check one)

Internal combustion Use Form ICE (Internal Combustion Engine) unless it is a gas turbine
☒ gas turbine
☐ other ______________________ __________hp

Incinerator
☐ salvage operation ☐ pathological waste Temperature ________°F
☐ liquid waste ☐ other ______________________ Residence time ________Sec

Others
☐ boiler ☐ dryer
☐ afterburner ☐ oven
☐ flare ☐ furnace Material dried, baked, or heated: ______________________
☐ open burning ☐ kiln
☐ other ______________________

8. Overfire air? ☐ yes ☒ no If yes, what percent _______%
9. Flue gas recirculation? ☐ yes ☒ no If yes, what percent _______%
10. Air preheat? ☐ yes ☒ no Temperature _______°F
11. Low NO_x burners? ☒ yes ☐ no Make, Model Siemens, Ultra Low NOx Combustor_____________
12. Maximum flame temperature ________°F
13. Combustion products: Wet gas flowrate 1,378,149 acfm at 340 °F
Typical Oxygen Content _____ dry volume % or _____ wet volume % or _____ % excess air
14. Typical Use 24 hours/day 7 days/week 26 weeks/year (4,383 hrs/yr)
15. Typical % of annual total: Dec-Feb 25% Mar-May 25% Jun-Aug 25% Sep-Nov 25%

16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
S _______ **S** _______ **S** _______ **S** _______ **S** _______ **S** _______ **A** _______ **A** _______ **A** _______

With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
S _______ **S** _______ **A** 1 **A** 2 **P** 1 **P** _______

Person completing this form: Mark Strehlow Date: June 19, 2008

(revised 4/05)

FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

SECTION A: FUEL DATA

	Fuel Name	*Fuel Code***	*Total Annual Usage****	*Maximum Possible Fuel Use Rate*	*Typical Heat Content*	*Sulfur Content*	*Nitrogen Content (optional)*	*Ash Content (optional)*
1.	Natural Gas		9.95E+07	2271 MM	N/A	N/A	N/A	N/A
2.								
3.								
4.								
5.								

Use the appropriate units for each fuel	Natural Gas	therm*	Btu/hr	N/A	N/A	N/A	N/A
	Other Gas	MSCF*	MSCF/hr	Btu/MSCF	ppm	N/A	N/A
	Liquid	m gal*	m gal/hr	Btu/m gal	wt%	wt%	wt%
	Solid	ton	ton/hr	Btu/ton	wt%	wt%	wt%

SECTION B: EMISSION FACTORS (optional)

	Fuel Name	*Fuel Code***	Particulates		NOx		CO	
			Emission Factor	***Basis Code*	*Emission Factor*	***Basis Code*	*Emission Factor*	***Basis Code*
1.								
2.								
3.								
4.								

Use the appropriate units for each fuel: *Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
Solid = lb/ton

Note: * MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

Fuel Codes

Code	*Fuel*	*Code*	*Fuel*
25	Anthracite coal	189	Natural Gas
33	Bagasse	234	Process gas - blast furnace
35	Bark	235	Process gas - CO
43	Bituminous coal	236	Process gas - coke oven gas
47	Brown coal	238	Process gas - RMG
242	Bunker C fuel oil	237	Process gas - other
80	Coke	242	Residual oil
89	Crude oil	495	Refuse derived fuel
98	Diesel oil	511	Landfill gas
493	Digester gas	256	Solid propellant
315	Distillate oil	466	Solid waste
392	Fuel oil #2	304	Wood - hogged
551	Gasoline	305	Wood - other
158	Jet fuel	198	Other - gaseous fuels
160	LPG	200	Other - liquid fuels
165	Lignite	203	Other - solid fuels
167	Liquid waste		
494	Municipal solid waste		

Basis Codes

Code	*Method*
0	Not applicable for this pollutant
1	Source testing or other measurement by plant (attach copy)
2	Source testing or other measurement by BAAQMD (give date)
3	Specifications from vendor (attach copy)
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance by BAAQMD
6	Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA)
7	Taken from literature, other than AP-42 (attach copy)
8	Guess

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
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Website: www.baaqmd.gov

(revised: 6/01) **Data Form C**
FUEL COMBUSTION SOURCE

(for District use only)

New ☐ Modified ☐ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

(If unknown, leave blank)

1. Company Name: Mirant Marsh Landing, LLC Plant No: Source No. S-2
2. Equipment Name & Number, or Description: Natural Gas-Fired CTG #2
3. Make, Model : Siemens FP10 Natural Gas-Fired CTG Maximum firing rate: 2271MM Btu/hr
4. Date of modification or initial operation: ________________ *(if unknown, leave blank)*
5. Primary use (check one): ☒ electrical generation ☐ space heat ☐ waste disposal ☐ testing ☐ abatement device ☐ cogeneration ☐ resource recovery ☐ other ☐ process heat; material heated ______________________________
6. SIC Number__________________ (If unknown leave blank)
7. Equipment type (check one)

Internal combustion Use Form ICE (Internal Combustion Engine) unless it is a gas turbine
☒ gas turbine
☐ other __________________________ ___________hp

Incinerator
☐ salvage operation ☐ pathological waste Temperature ________°F
☐ liquid waste ☐ other ________________________ Residence time ________Sec

Others
☐ boiler ☐ dryer
☐ afterburner ☐ oven
☐ flare ☐ furnace Material dried, baked, or heated:
☐ open burning ☐ kiln ______________________________
☐ other ______________________________

8. Overfire air? ☐ yes ☒ no If yes, what percent _______%
9. Flue gas recirculation? ☐ yes ☒ no If yes, what percent _______%
10. Air preheat? ☐ yes ☒ no Temperature _______°F
11. Low NO_x burners? ☒ yes ☐ no Make, Model Siemens, Ultra Low NOx Combustor_____________
12. Maximum flame temperature ________°F
13. Combustion products: Wet gas flowrate 1,378,149 acfm at 340 °F
Typical Oxygen Content _____ dry volume % or _____ wet volume % or _____ % excess air
14. Typical Use 24 hours/day 7 days/week 26 weeks/year (4,383 hrs/yr)
15. Typical % of annual total: Dec-Feb 25% Mar-May 25% Jun-Aug 25% Sep-Nov 25%
16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
S _______ **S** _______ **S** _______ **S** _______ **S** _______ **S** _______ **A** _______ **A** _______ **A** _______

With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
S _______ **S** _______ **A** 3 **A** 4 **P** 2 **P** _______

Person completing this form: Mark Strehlow Date: June 19, 2008

(revised 4/05)

FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

SECTION A: FUEL DATA

	Fuel Name	Fuel Code**	Total Annual Usage***	Maximum Possible Fuel Use Rate	Typical Heat Content	Sulfur Content	Nitrogen Content (optional)	Ash Content (optional)
1.	Natural Gas		9.95E+07	2271 MM	N/A	N/A	N/A	N/A
2.								
3.								
4.								
5.								

Use the appropriate units for each fuel	Natural Gas	therm*	Btu/hr	N/A	N/A	N/A	N/A
	Other Gas	MSCF*	MSCF/hr	Btu/MSCF	ppm	N/A	N/A
	Liquid	m gal*	m gal/hr	Btu/m gal	wt%	wt%	wt%
	Solid	ton	ton/hr	Btu/ton	wt%	wt%	wt%

SECTION B: EMISSION FACTORS (optional)

	Fuel Name	Fuel Code**	Particulates		NOx		CO	
			Emission Factor	**Basis Code	Emission Factor	**Basis Code	Emission Factor	**Basis Code
1.								
2.								
3.								
4.								

Use the appropriate units for each fuel: *Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
Solid = lb/ton

Note: * MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

Fuel Codes Code	Fuel	Code	Fuel
25	Anthracite coal	189	Natural Gas
33	Bagasse	234	Process gas - blast furnace
35	Bark	235	Process gas - CO
43	Bituminous coal	236	Process gas - coke oven gas
47	Brown coal	238	Process gas - RMG
242	Bunker C fuel oil	237	Process gas - other
80	Coke	242	Residual oil
89	Crude oil	495	Refuse derived fuel
98	Diesel oil	511	Landfill gas
493	Digester gas	256	Solid propellant
315	Distillate oil	466	Solid waste
392	Fuel oil #2	304	Wood - hogged
551	Gasoline	305	Wood - other
158	Jet fuel	198	Other - gaseous fuels
160	LPG	200	Other - liquid fuels
165	Lignite	203	Other - solid fuels
167	Liquid waste		
494	Municipal solid waste		

Basis Codes Code	Method
0	Not applicable for this pollutant
1	Source testing or other measurement by plant (attach copy)
2	Source testing or other measurement by BAAQMD (give date)
3	Specifications from vendor (attach copy)
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance by BAAQMD
6	Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA)
7	Taken from literature, other than AP-42 (attach copy)
8	Guess

(revised: 6/01)

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
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Website: www.baaqmd.gov

Data Form C
FUEL COMBUSTION SOURCE

(for District use only)

New ☐ Modified ☐ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

1. Company Name: Mirant Marsh Landing, LLC   Plant No: (If unknown, leave blank)   Source No. S-3
2. Equipment Name & Number, or Description: Natural Gas-Fired CTG #3
3. Make, Model : Siemens SGT6 5000F Natural Gas-Fired CTG   Maximum firing rate: 2202MM Btu/hr
4. Date of modification or initial operation: ________________ *(if unknown, leave blank)*
5. Primary use (check one): ☒ electrical generation ☐ space heat ☐ waste disposal ☐ testing ☐ abatement device ☐ cogeneration ☐ resource recovery ☐ other ☐ process heat; material heated ________________
6. SIC Number__________ (If unknown leave blank)
7. Equipment type (check one)

Internal combustion Use Form ICE (Internal Combustion Engine) unless it is a gas turbine
☒ gas turbine
☐ other ____________ ________hp

Incinerator ☐ salvage operation ☐ pathological waste Temperature ________°F
☐ liquid waste ☐ other ____________ Residence time ________Sec

Others ☐ boiler ☐ dryer
☐ afterburner ☐ oven
☐ flare ☐ furnace Material dried, baked, or heated: ________________
☐ open burning ☐ kiln
☐ other ________________

8. Overfire air? ☐ yes ☒ no If yes, what percent _______%
9. Flue gas recirculation? ☐ yes ☒ no If yes, what percent _______%
10. Air preheat? ☐ yes ☒ no Temperature _______°F
11. Low NO_x burners? ☒ yes ☐ no Make, Model Siemens, Ultra Low NOx Combustor_____________
12. Maximum flame temperature ________°F
13. Combustion products: Wet gas flowrate 3,159,287 acfm at 750 °F
Typical Oxygen Content _____ dry volume % or _____ wet volume % or _____ % excess air
14. Typical Use 24 hours/day 7 days/week 5.2 weeks/year (877 hrs/yr)
15. Typical % of annual total: Dec-Feb 25% Mar-May 25% Jun-Aug 25% Sep-Nov 25%
16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
S _______ **S** _______ **S** _______ **S** _______ **S** _______ **S** _______ **A** _______ **A** _______ **A** _______

With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
S _______ **S** _______ **A** 5 **A** 6 **P** 3 **P** _______

Person completing this form: Mark Strehlow   Date: June 19, 2008

(revised 4/05)

FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

SECTION A: FUEL DATA

	Fuel Name	*Fuel Code***	*Total Annual Usage****	*Maximum Possible Fuel Use Rate*	*Typical Heat Content*	*Sulfur Content*	*Nitrogen Content (optional)*	*Ash Content (optional)*
1.	Natural Gas		1.93E+7	2202 MM	N/A	N/A	N/A	N/A
2.								
3.								
4.								
5.								

Use the appropriate units for each fuel	Natural Gas	therm*	Btu/hr	N/A	N/A	N/A	N/A
	Other Gas	MSCF*	MSCF/hr	Btu/MSCF	ppm	N/A	N/A
	Liquid	m gal*	m gal/hr	Btu/m gal	wt%	wt%	wt%
	Solid	ton	ton/hr	Btu/ton	wt%	wt%	wt%

SECTION B: EMISSION FACTORS (optional)

	Fuel Name	*Fuel Code***	**Particulates**		**NOx**		**CO**	
			Emission Factor	***Basis Code*	*Emission Factor*	***Basis Code*	*Emission Factor*	***Basis Code*
1.								
2.								
3.								
4.								

Use the appropriate units for each fuel: *Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
Solid = lb/ton

Note: * MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

****Fuel Codes**

Code	*Fuel*	*Code*	*Fuel*
25	Anthracite coal	189	Natural Gas
33	Bagasse	234	Process gas - blast furnace
35	Bark	235	Process gas - CO
43	Bituminous coal	236	Process gas - coke oven gas
47	Brown coal	238	Process gas - RMG
242	Bunker C fuel oil	237	Process gas - other
80	Coke	242	Residual oil
89	Crude oil	495	Refuse derived fuel
98	Diesel oil	511	Landfill gas
493	Digester gas	256	Solid propellant
315	Distillate oil	466	Solid waste
392	Fuel oil #2	304	Wood - hogged
551	Gasoline	305	Wood - other
158	Jet fuel	198	Other - gaseous fuels
160	LPG	200	Other - liquid fuels
165	Lignite	203	Other - solid fuels
167	Liquid waste		
494	Municipal solid waste		

****Basis Codes**

Code	*Method*
0	Not applicable for this pollutant
1	Source testing or other measurement by plant (attach copy)
2	Source testing or other measurement by BAAQMD (give date)
3	Specifications from vendor (attach copy)
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance by BAAQMD
6	Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA)
7	Taken from literature, other than AP-42 (attach copy)
8	Guess

(revised: 6/01)

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
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Website: www.baaqmd.gov

Data Form C
FUEL COMBUSTION SOURCE

(for District use only)

New ☐ Modified ☐ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

(If unknown, leave blank)

1. Company Name: Mirant Marsh Landing, LLC Plant No: Source No. S-4
2. Equipment Name & Number, or Description: Natural Gas-Fired CTG #4
3. Make, Model : Siemens SGT6 5000F Natural Gas-Fired CTG Maximum firing rate: 2202MM Btu/hr
4. Date of modification or initial operation: ________________ *(if unknown, leave blank)*
5. Primary use (check one): ☒ electrical generation ☐ space heat ☐ waste disposal ☐ testing ☐ abatement device ☐ cogeneration ☐ resource recovery ☐ other ☐ process heat; material heated________________________________
6. SIC Number________________
   If unknown leave blank
7. Equipment type (check one)

Internal combustion Use Form ICE (Internal Combustion Engine) unless it is a gas turbine

☒ gas turbine
☐ other ________________________ ___________hp

Incinerator ☐ salvage operation ☐ pathological waste Temperature ________°F
☐ liquid waste ☐ other ______________________ Residence time ________Sec

Others ☐ boiler ☐ dryer
☐ afterburner ☐ oven
☐ flare ☐ furnace Material dried, baked, or heated:
☐ open burning ☐ kiln ________________________________
☐ other ____

8. Overfire air? ☐ yes ☒ no If yes, what percent _______%
9. Flue gas recirculation? ☐ yes ☒ no If yes, what percent _______%
10. Air preheat? ☐ yes ☒ no Temperature _______°F
11. Low NO_x burners? ☒ yes ☐ no Make, Model Siemens, Ultra Low NOx Combustor_____________
12. Maximum flame temperature ________°F
13. Combustion products: Wet gas flowrate 3,159,287 acfm at 750 °F
    Typical Oxygen Content _____ dry volume % or _____ wet volume % or _____ % excess air
14. Typical Use 24 hours/day 7 days/week 5.2 weeks/year (877 hrs/yr)
15. Typical % of annual total: Dec-Feb 25% Mar-May 25% Jun-Aug 25% Sep-Nov 25%
16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
    S _______ **S** _______ **S** _______ **S** _______ **S** _______ **S** _______ **A** _______ **A** _______ **A** _______

    With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
    S _______ **S** _______ **A** 7 **A** 8 **P** 4 **P** _______

Person completing this form: Mark Strehlow Date: June 19, 2008

(revised 4/05)

FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

SECTION A: FUEL DATA

	Fuel Name	*Fuel Code***	*Total Annual Usage****	*Maximum Possible Fuel Use Rate*	*Typical Heat Content*	*Sulfur Content*	*Nitrogen Content (optional)*	*Ash Content (optional)*
1.	Natural Gas		1.93E+7	2202 MM	N/A	N/A	N/A	N/A
2.								
3.								
4.								
5.								

Use the appropriate units for each fuel	Natural Gas	therm*	Btu/hr	N/A	N/A	N/A	N/A
	Other Gas	MSCF*	MSCF/hr	Btu/MSCF	ppm	N/A	N/A
	Liquid	m gal*	m gal/hr	Btu/m gal	wt%	wt%	wt%
	Solid	ton	ton/hr	Btu/ton	wt%	wt%	wt%

SECTION B: EMISSION FACTORS (optional)

	Fuel Name	***Fuel Code***	**Particulates**		**NOx**		**CO**	
			Emission Factor	***Basis Code*	*Emission Factor*	***Basis Code*	*Emission Factor*	***Basis Code*
1.								
2.								
3.								
4.								

Use the appropriate units for each fuel: *Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
Solid = lb/ton

Note: * MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

***Fuel Codes**				***Basis Codes**	
Code	*Fuel*	*Code*	*Fuel*	*Code*	*Method*
25	Anthracite coal	189	Natural Gas	0	Not applicable for this pollutant
33	Bagasse	234	Process gas - blast furnace	1	Source testing or other measurement by plant (attach copy)
35	Bark	235	Process gas - CO	2	Source testing or other measurement by BAAQMD (give date)
43	Bituminous coal	236	Process gas - coke oven gas	3	Specifications from vendor (attach copy)
47	Brown coal	238	Process gas - RMG	4	Material balance by plant using engineering expertise and knowledge of process
242	Bunker C fuel oil	237	Process gas - other		
80	Coke	242	Residual oil	5	Material balance by BAAQMD
89	Crude oil	495	Refuse derived fuel	6	Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA)
98	Diesel oil	511	Landfill gas		
493	Digester gas	256	Solid propellant	7	Taken from literature, other than AP-42 (attach copy)
315	Distillate oil	466	Solid waste	8	Guess
392	Fuel oil #2	304	Wood - hogged		
551	Gasoline	305	Wood - other		
158	Jet fuel	198	Other - gaseous fuels		
160	LPG	200	Other - liquid fuels		
165	Lignite	203	Other - solid fuels		
167	Liquid waste				
494	Municipal solid waste				

(revised: 6/01)

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . fax (415) 749-5030
Website: www.baaqmd.gov

Data Form C
FUEL COMBUSTION SOURCE

(for District use only)

New ☐ Modified ☐ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

(If unknown, leave blank)

1. Company Name: Mirant Marsh Landing, LLC Plant No: Source No. S-5
2. Equipment Name & Number, or Description: Natural Gas-Fired Fuel Preheater (Serving S-1 and S-2)
3. Make, Model : TBD Maximum firing rate: 5MM Btu/hr
4. Date of modification or initial operation: ______________ *(if unknown, leave blank)*
5. Primary use (check one): ☐ electrical generation ☐ space heat ☐ waste disposal ☐ testing ☐ abatement device ☐ cogeneration ☐ resource recovery ☐ other ☒ process heat; material heated________________________________
6. SIC Number______________
   If unknown leave blank
7. Equipment type (check one)

Internal combustion Use Form ICE (Internal Combustion Engine) unless it is a gas turbine

☐ gas turbine
☐ other ____________________ __________hp

Incinerator ☐ salvage operation ☐ pathological waste Temperature _______°F
☐ liquid waste ☐ other ____________________ Residence time _______Sec

Others
☐ boiler ☐ dryer
☐ afterburner ☐ oven
☐ flare ☐ furnace Material dried, baked, or heated:
☐ open burning ☐ kiln ______________________________
☒ other Nat Gas Fired Fuel Preheater_______________________________

8. Overfire air? ☐ yes ☒ no If yes, what percent _______%
9. Flue gas recirculation? ☐ yes ☒ no If yes, what percent _______%
10. Air preheat? ☐ yes ☒ no Temperature _______°F
11. Low NO_x burners? ☐ yes ☒ no Make, Model ______________________________
12. Maximum flame temperature _______°F
13. Combustion products: Wet gas flowrate 1048 acfm at 415 °F
    Typical Oxygen Content _____ dry volume % or _____ wet volume % or _____ % excess air
14. Typical Use 24 hours/day 7 days/week 26 weeks/year (4383 hrs/yr)
15. Typical % of annual total: Dec-Feb 25% Mar-May 25% Jun-Aug 25% Sep-Nov 25%
16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
    S _______ **S** _______ **S** _______ **S** _______ **S** _______ **S** _______ **A** _______ **A** _______ **A** _______

    With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
    S _______ **S** _______ **A** _______ **A** _______ **P** 5 **P** _______

Person completing this form: Mark Strehlow Date: June 19, 2008

(revised 4/05)

FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

SECTION A: FUEL DATA

	Fuel Name	*Fuel Code***	*Total Annual Usage****	*Maximum Possible Fuel Use Rate*	*Typical Heat Content*	*Sulfur Content*	*Nitrogen Content (optional)*	*Ash Content (optional)*
1.	Natural Gas		2.19E+5	5MM	N/A	N/A	N/A	N/A
2.								
3.								
4.								
5.								

Use the appropriate units for each fuel	Natural Gas	therm*	Btu/hr	N/A	N/A	N/A	N/A
	Other Gas	MSCF*	MSCF/hr	Btu/MSCF	ppm	N/A	N/A
	Liquid	m gal*	m gal/hr	Btu/m gal	wt%	wt%	wt%
	Solid	ton	ton/hr	Btu/ton	wt%	wt%	wt%

SECTION B: EMISSION FACTORS (optional)

	Fuel Name	***Fuel Code****	**Particulates**		**NOx**		**CO**	
			Emission Factor	***Basis Code*	*Emission Factor*	***Basis Code*	*Emission Factor*	***Basis Code*
1.								
2.								
3.								
4.								

Use the appropriate units for each fuel: *Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
Solid = lb/ton

Note: * MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

****Fuel Codes**

Code	Fuel	Code	Fuel
25	Anthracite coal	189	Natural Gas
33	Bagasse	234	Process gas - blast furnace
35	Bark	235	Process gas - CO
43	Bituminous coal	236	Process gas - coke oven gas
47	Brown coal	238	Process gas - RMG
242	Bunker C fuel oil	237	Process gas - other
80	Coke	242	Residual oil
89	Crude oil	495	Refuse derived fuel
98	Diesel oil	511	Landfill gas
493	Digester gas	256	Solid propellant
315	Distillate oil	466	Solid waste
392	Fuel oil #2	304	Wood - hogged
551	Gasoline	305	Wood - other
158	Jet fuel	198	Other - gaseous fuels
160	LPG	200	Other - liquid fuels
165	Lignite	203	Other - solid fuels
167	Liquid waste		
494	Municipal solid waste		

****Basis Codes**

Code	Method
0	Not applicable for this pollutant
1	Source testing or other measurement by plant (attach copy)
2	Source testing or other measurement by BAAQMD (give date)
3	Specifications from vendor (attach copy)
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance by BAAQMD
6	Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA)
7	Taken from literature, other than AP-42 (attach copy)
8	Guess

(revised: 6/01)

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . fax (415) 749-5030
Website: www.baaqmd.gov

Data Form C
FUEL COMBUSTION SOURCE

(for District use only)

New ☐ Modified ☐ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

(If unknown, leave blank)

1. Company Name: Mirant Marsh Landing, LLC Plant No: Source No. S-6

2. Equipment Name & Number, or Description: Natural Gas-Fired Fuel Preheater (Serving S-3 and S-4)

3. Make, Model : TBD Maximum firing rate: 5MM Btu/hr

4. Date of modification or initial operation: ________________ *(if unknown, leave blank)*

5. Primary use (check one): ☐ electrical generation ☐ space heat ☐ waste disposal ☐ testing ☐ abatement device ☐ cogeneration ☐ resource recovery ☐ other ☒ process heat; material heated ____________

6. SIC Number____________
If unknown leave blank

7. Equipment type (check one)

Internal combustion Use Form ICE (Internal Combustion Engine) unless it is a gas turbine
☐ gas turbine
☐ other ____________ ____________hp

Incinerator ☐ salvage operation ☐ pathological waste Temperature ________°F
☐ liquid waste ☐ other ____________ Residence time ________Sec

Others ☐ boiler ☐ dryer
☐ afterburner ☐ oven
☐ flare ☐ furnace Material dried, baked, or heated:
☐ open burning ☐ kiln ____________
☒ other Nat Gas Fired Fuel Preheater ____________

8. Overfire air? ☐ yes ☒ no If yes, what percent _______%
9. Flue gas recirculation? ☐ yes ☒ no If yes, what percent _______%
10. Air preheat? ☐ yes ☒ no Temperature _______°F
11. Low NO_x burners? ☐ yes ☒ no Make, Model ____________
12. Maximum flame temperature _______°F

13. Combustion products: Wet gas flowrate 1048 acfm at 415 °F
Typical Oxygen Content _____ dry volume % or _____ wet volume % or _____ % excess air

14. Typical Use 24 hours/day 7 days/week 5.2 weeks/year (877 hrs/yr)

15. Typical % of annual total: Dec-Feb 25% Mar-May 25% Jun-Aug 25% Sep-Nov 25%

16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
S ______ **S** ______ **S** ______ **S** ______ **S** ______ **S** ______ **A** ______ **A** ______ **A** ______

With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
S ______ **S** ______ **A** ______ **A** ______ **P** 6 **P** ______

Person completing this form: Mark Strehlow Date: June 19, 2008

(revised 4/05)

FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

SECTION A: FUEL DATA

	Fuel Name	Fuel Code**	Total Annual Usage***	Maximum Possible Fuel Use Rate	Typical Heat Content	Sulfur Content	Nitrogen Content (optional)	Ash Content (optional)
1.	Natural Gas		43,850	5MM	N/A	N/A	N/A	N/A
2.								
3.								
4.								
5.								

Use the appropriate units for each fuel	Natural Gas	therm*	Btu/hr	N/A	N/A	N/A	N/A
	Other Gas	MSCF*	MSCF/hr	Btu/MSCF	ppm	N/A	N/A
	Liquid	m gal*	m gal/hr	Btu/m gal	wt%	wt%	wt%
	Solid	ton	ton/hr	Btu/ton	wt%	wt%	wt%

SECTION B: EMISSION FACTORS (optional)

	Fuel Name	Fuel Code**	Particulates		NOx		CO	
			Emission Factor	***Basis Code*	*Emission Factor*	***Basis Code*	*Emission Factor*	***Basis Code*
1.								
2.								
3.								
4.								

Use the appropriate units for each fuel: *Natural Gas* = *lb/therm**
Other Gas = *lb/MSCF**
Liquid = *lb/m gal**
Solid = *lb/ton*

Note: * MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

Fuel Codes			
Code	**Fuel**	**Code**	**Fuel**
25	Anthracite coal	189	Natural Gas
33	Bagasse	234	Process gas - blast furnace
35	Bark	235	Process gas - CO
43	Bituminous coal	236	Process gas - coke oven gas
47	Brown coal	238	Process gas - RMG
242	Bunker C fuel oil	237	Process gas - other
80	Coke	242	Residual oil
89	Crude oil	495	Refuse derived fuel
98	Diesel oil	511	Landfill gas
493	Digester gas	256	Solid propellant
315	Distillate oil	466	Solid waste
392	Fuel oil #2	304	Wood - hogged
551	Gasoline	305	Wood - other
158	Jet fuel	198	Other - gaseous fuels
160	LPG	200	Other - liquid fuels
165	Lignite	203	Other - solid fuels
167	Liquid waste		
494	Municipal solid waste		

Basis Codes	
Code	**Method**
0	Not applicable for this pollutant
1	Source testing or other measurement by plant (attach copy)
2	Source testing or other measurement by BAAQMD (give date)
3	Specifications from vendor (attach copy)
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance by BAAQMD
6	Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA)
7	Taken from literature, other than AP-42 (attach copy)
8	Guess

(revised: 6/01)

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Mirant Marsh Landing, LLC Plant No: ______
(If unknown, leave blank)

2. Name or Description CO Catalyst System Abatement Device No: A- 1

3. Make, Model, and Rated Capacity TBD

4. Abatement Device Code (See table*) 2 Date of Initial Operation ______

5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 1 **S-** ______ **S-** ______ **S-** ______ **S-** ______
S- ______ **A-** ______ **A-** ______ **A-** ______ **A-** ______ **A-** ______

6. Typical gas stream temperature at inlet: 750 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics	< 2 ppmvd@15%O2	
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide	< 3 ppmvd@15%O2	
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ______ **A-** 2 ______ **A-** ______ **A-** ______ **P-** 1 **P-** ______

Person completing this form: Mark Strehlow Date: June 19, 2008

*ABATEMENT DEVICE CODES

Code	DEVICE
	ADSORBER (See Vapor Recovery)
	AFTERBURNER
1	CO Boiler
2	Catalytic
3	Direct Flame
4	Flare
5	Furnace-firebox
6	Other
	BAGHOUSE (See Dry Filter)
	CYCLONE (See Dry Inertial Collector and Scrubber)
	DUST CONTROL
68	Water Spray
	DRY FILTER
7	Absolute
8	Baghouse, Pulse Jet
9	Baghouse, Reverse Air
10	Baghouse, Reverse Jet
11	Baghouse, Shaking
12	Baghouse, Simple
13	Baghouse, Other
14	Envelope
15	Moving Belt
16	Other
	DRY INERTIAL COLLECTOR
17	Cyclone, Dynamic
18	Cyclone, Multiple (12 inches dia. or more)
19	Cyclone, Multiple (less than 12 inches dia.)
20	Cyclone, Simple
21	Settling Chamber, Baffled/Louvered
22	Settling Chamber, Simple
23	Other
	ELECTROSTATIC PRECIPITATOR
24	Single Stage
25	Single Stage, Wet
26	Two Stage
27	Two Stage, Wet
28	Other
	INCINERATOR (See Afterburner)
	INTERNAL COMBUSTION ENGINE CONTROL
69	Catalyzed Diesel Particulate Filter
70	Non-Cat. Diesel Part. Filter w/ Active Regeneration
71	Diesel Oxidation Catalyst
72	Oxidation Catalyst
	INCINERATOR (See Afterburner)
	KNOCK-OUT POT (See Liquid Separator)
	LIQUID SEPARATOR
29	Knock-out Pot
30	Mist Eliminator, Horizontal Pad, Dry
31	Mist Eliminator, Panel, Dry
32	Mist Eliminator, Spray/Irrigated
33	Mist Eliminator, Vertical Tube, Dry
34	Mist Eliminator, Other
35	Other
	MIST ELIMINATOR (See Liquid Separator)

Code	DEVICE
	NO_X CONTROL
66	Selective Catalytic Reduction (SCR)
67	Non-Selective Catalytic Reduction (NSCR)
73	Selective Non-Catalytic Reduction (SNCR)
	SCRUBBER
36	Baffle and Secondary Flow
37	Centrifugal
38	Cyclone, Irrigated
39	Fibrous Packed
40	Impingement Plate
41	Impingement and Entrainment
42	Mechanically Aided
43	Moving Bed
44	Packed Bed
45	Preformed Spray
46	Venturi
47	Other
	SETTLING CHAMBER (See Dry Inertial Collector)
	SULFUR DIOXIDE CONTROL
48	Absorption and Regeneration, for Sulfur Plant
49	Claus Solution Reaction, for Sulfur Plant
50	Dual Absorption, for H2S04 Plant
51	Flue Gas Desulfurization, for Fossil Fuel Combustion
52	Reduction and Solution Regeneration, for Sulfur Plant
53	Reduction and Stretford Process, for Sulfur Plant
54	Sodium Sulfite-Bisulfite Scrubber, for H2S04 Plant
55	Other
	VAPOR RECOVERY
56	Adsorption, Activated Carbon/Charcoal
57	Adsorption, Silica
58	Adsorption, Other
59	Balance
60	Compression/Condensation/Absorption
61	Compression/Refrigeration
62	Condenser, Water-Cooled
63	Condenser, Other
64	Other
	MISCELLANEOUS
65	Not classified above

**BASIS CODES

Code	Method
0	Not applicable for this pollutant
1	Source testing or other measurement **by plant**
2	Source testing or other measurement **by BAAQMD**
3	Specifications from vendor
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance **by BAAQMD** using engineering expertise and knowledge of process
6	Taken from AP-42 ("Compilation of Air Pollutant Emission Factors," EPA)
7	Taken from literature, other than AP-42
8	Guess

(revised: 9/05)

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Mirant Marsh Landing, LLC Plant No: ______ (If unknown, leave blank)

2. Name or Description Selective Catalytic Reduction Abatement Device No: A- 2

3. Make, Model, and Rated Capacity TBD

4. Abatement Device Code (See table*) 2 Date of Initial Operation ______

5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 1 **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** 1 **A-** ____ **A-** ____ **A-** ____ **A-** ____

6. Typical gas stream temperature at inlet: 750 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics		
9.	Nitrogen Oxides (as NO_2)	2.0 ppmvd	
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ **A-** ____ ____ **A-** ____ **A-** ____ **P-** 1 **P-** ____

Person completing this form: Mark Strehlow	Date: June 19, 2008

*ABATEMENT DEVICE CODES

Code	DEVICE
	ADSORBER (See Vapor Recovery)
	AFTERBURNER
1	CO Boiler
2	Catalytic
3	Direct Flame
4	Flare
5	Furnace-firebox
6	Other
	BAGHOUSE (See Dry Filter)
	CYCLONE (See Dry Inertial Collector and Scrubber)
	DUST CONTROL
68	Water Spray
	DRY FILTER
7	Absolute
8	Baghouse, Pulse Jet
9	Baghouse, Reverse Air
10	Baghouse, Reverse Jet
11	Baghouse, Shaking
12	Baghouse, Simple
13	Baghouse, Other
14	Envelope
15	Moving Belt
16	Other
	DRY INERTIAL COLLECTOR
17	Cyclone, Dynamic
18	Cyclone, Multiple (12 inches dia. or more)
19	Cyclone, Multiple (less than 12 inches dia.)
20	Cyclone, Simple
21	Settling Chamber, Baffled/Louvered
22	Settling Chamber, Simple
23	Other
	ELECTROSTATIC PRECIPITATOR
24	Single Stage
25	Single Stage, Wet
26	Two Stage
27	Two Stage, Wet
28	Other
	INCINERATOR (See Afterburner)
	INTERNAL COMBUSTION ENGINE CONTROL
69	Catalyzed Diesel Particulate Filter
70	Non-Cat. Diesel Part. Filter w/ Active Regeneration
71	Diesel Oxidation Catalyst
72	Oxidation Catalyst
	INCINERATOR (See Afterburner)
	KNOCK-OUT POT (See Liquid Separator)
	LIQUID SEPARATOR
29	Knock-out Pot
30	Mist Eliminator, Horizontal Pad, Dry
31	Mist Eliminator, Panel, Dry
32	Mist Eliminator, Spray/Irrigated
33	Mist Eliminator, Vertical Tube, Dry
34	Mist Eliminator, Other
35	Other
	MIST ELIMINATOR (See Liquid Separator)

Code	DEVICE
	NO_X CONTROL
66	Selective Catalytic Reduction (SCR)
67	Non-Selective Catalytic Reduction (NSCR)
73	Selective Non-Catalytic Reduction (SNCR)
	SCRUBBER
36	Baffle and Secondary Flow
37	Centrifugal
38	Cyclone, Irrigated
39	Fibrous Packed
40	Impingement Plate
41	Impingement and Entrainment
42	Mechanically Aided
43	Moving Bed
44	Packed Bed
45	Preformed Spray
46	Venturi
47	Other
	SETTLING CHAMBER (See Dry Inertial Collector)
	SULFUR DIOXIDE CONTROL
48	Absorption and Regeneration, for Sulfur Plant
49	Claus Solution Reaction, for Sulfur Plant
50	Dual Absorption, for H2S04 Plant
51	Flue Gas Desulfurization, for Fossil Fuel Combustion
52	Reduction and Solution Regeneration, for Sulfur Plant
53	Reduction and Stretford Process, for Sulfur Plant
54	Sodium Sulfite-Bisulfite Scrubber, for H2S04 Plant
55	Other
	VAPOR RECOVERY
56	Adsorption, Activated Carbon/Charcoal
57	Adsorption, Silica
58	Adsorption, Other
59	Balance
60	Compression/Condensation/Absorption
61	Compression/Refrigeration
62	Condenser, Water-Cooled
63	Condenser, Other
64	Other
	MISCELLANEOUS
65	Not classified above

**BASIS CODES

Code	Method
0	Not applicable for this pollutant
1	Source testing or other measurement **by plant**
2	Source testing or other measurement **by BAAQMD**
3	Specifications from vendor
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance **by BAAQMD** using engineering expertise and knowledge of process
6	Taken from AP-42 ("Compilation of Air Pollutant Emission Factors," EPA)
7	Taken from literature, other than AP-42
8	Guess

(revised: 9/05)

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Mirant Marsh Landing, LLC Plant No: ______
(If unknown, leave blank)

2. Name or Description CO Catalyst System Abatement Device No: A- 3

3. Make, Model, and Rated Capacity TBD

4. Abatement Device Code (See table*) 2 Date of Initial Operation ______

5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 2 **S-** ______ **S-** ______ **S-** ______ **S-** ______
S- ______ **A-** ______ **A-** ______ **A-** ______ **A-** ______ **A-** ______

6. Typical gas stream temperature at inlet: 750 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics	< 2 ppmvd@15%O2	
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide	< 3 ppmvd@15%O2	
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ______ **A-** 4 ______ **A-** ______ **A-** ______ **P-** 2 **P-** ______

Person completing this form: Mark Strehlow Date: June 19, 2008

*ABATEMENT DEVICE CODES

Code	DEVICE
	ADSORBER (See Vapor Recovery)
	AFTERBURNER
1	CO Boiler
2	Catalytic
3	Direct Flame
4	Flare
5	Furnace-firebox
6	Other
	BAGHOUSE (See Dry Filter)
	CYCLONE (See Dry Inertial Collector and Scrubber)
	DUST CONTROL
68	Water Spray
	DRY FILTER
7	Absolute
8	Baghouse, Pulse Jet
9	Baghouse, Reverse Air
10	Baghouse, Reverse Jet
11	Baghouse, Shaking
12	Baghouse, Simple
13	Baghouse, Other
14	Envelope
15	Moving Belt
16	Other
	DRY INERTIAL COLLECTOR
17	Cyclone, Dynamic
18	Cyclone, Multiple (12 inches dia. or more)
19	Cyclone, Multiple (less than 12 inches dia.)
20	Cyclone, Simple
21	Settling Chamber, Baffled/Louvered
22	Settling Chamber, Simple
23	Other
	ELECTROSTATIC PRECIPITATOR
24	Single Stage
25	Single Stage, Wet
26	Two Stage
27	Two Stage, Wet
28	Other
	INCINERATOR (See Afterburner)
	INTERNAL COMBUSTION ENGINE CONTROL
69	Catalyzed Diesel Particulate Filter
70	Non-Cat. Diesel Part. Filter w/ Active Regeneration
71	Diesel Oxidation Catalyst
72	Oxidation Catalyst
	INCINERATOR (See Afterburner)
	KNOCK-OUT POT (See Liquid Separator)
	LIQUID SEPARATOR
29	Knock-out Pot
30	Mist Eliminator, Horizontal Pad, Dry
31	Mist Eliminator, Panel, Dry
32	Mist Eliminator, Spray/Irrigated
33	Mist Eliminator, Vertical Tube, Dry
34	Mist Eliminator, Other
35	Other
	MIST ELIMINATOR (See Liquid Separator)

Code	DEVICE
	NO_X CONTROL
66	Selective Catalytic Reduction (SCR)
67	Non-Selective Catalytic Reduction (NSCR)
73	Selective Non-Catalytic Reduction (SNCR)
	SCRUBBER
36	Baffle and Secondary Flow
37	Centrifugal
38	Cyclone, Irrigated
39	Fibrous Packed
40	Impingement Plate
41	Impingement and Entrainment
42	Mechanically Aided
43	Moving Bed
44	Packed Bed
45	Preformed Spray
46	Venturi
47	Other
	SETTLING CHAMBER (See Dry Inertial Collector)
	SULFUR DIOXIDE CONTROL
48	Absorption and Regeneration, for Sulfur Plant
49	Claus Solution Reaction, for Sulfur Plant
50	Dual Absorption, for H2S04 Plant
51	Flue Gas Desulfurization, for Fossil Fuel Combustion
52	Reduction and Solution Regeneration, for Sulfur Plant
53	Reduction and Stretford Process, for Sulfur Plant
54	Sodium Sulfite-Bisulfite Scrubber, for H2S04 Plant
55	Other
	VAPOR RECOVERY
56	Adsorption, Activated Carbon/Charcoal
57	Adsorption, Silica
58	Adsorption, Other
59	Balance
60	Compression/Condensation/Absorption
61	Compression/Refrigeration
62	Condenser, Water-Cooled
63	Condenser, Other
64	Other
	MISCELLANEOUS
65	Not classified above

**BASIS CODES

Code	Method
0	Not applicable for this pollutant
1	Source testing or other measurement **by plant**
2	Source testing or other measurement **by BAAQMD**
3	Specifications from vendor
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance **by BAAQMD** using engineering expertise and knowledge of process
6	Taken from AP-42 ("Compilation of Air Pollutant Emission Factors," EPA)
7	Taken from literature, other than AP-42
8	Guess

(revised: 9/05)

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Mirant Marsh Landing, LLC Plant No: ______ (If unknown, leave blank)

2. Name or Description Selective Catalytic Reduction Abatement Device No: A- 4

3. Make, Model, and Rated Capacity TBD

4. Abatement Device Code (See table*) 2 Date of Initial Operation ______

5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 2 **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** 3 **A-** ____ **A-** ____ **A-** ____ **A-** ____

6. Typical gas stream temperature at inlet: 750 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics		
9.	Nitrogen Oxides (as NO_2)	2.0 ppmvd	
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ **A-** ____ **A-** ____ **A-** ____ **P-** 2 **P-** ____

Person completing this form: Mark Strehlow Date: June 19, 2008

*ABATEMENT DEVICE CODES

Code	DEVICE
	ADSORBER (See Vapor Recovery)
	AFTERBURNER
1	CO Boiler
2	Catalytic
3	Direct Flame
4	Flare
5	Furnace-firebox
6	Other
	BAGHOUSE (See Dry Filter)
	CYCLONE (See Dry Inertial Collector and Scrubber)
	DUST CONTROL
68	Water Spray
	DRY FILTER
7	Absolute
8	Baghouse, Pulse Jet
9	Baghouse, Reverse Air
10	Baghouse, Reverse Jet
11	Baghouse, Shaking
12	Baghouse, Simple
13	Baghouse, Other
14	Envelope
15	Moving Belt
16	Other
	DRY INERTIAL COLLECTOR
17	Cyclone, Dynamic
18	Cyclone, Multiple (12 inches dia. or more)
19	Cyclone, Multiple (less than 12 inches dia.)
20	Cyclone, Simple
21	Settling Chamber, Baffled/Louvered
22	Settling Chamber, Simple
23	Other
	ELECTROSTATIC PRECIPITATOR
24	Single Stage
25	Single Stage, Wet
26	Two Stage
27	Two Stage, Wet
28	Other
	INCINERATOR (See Afterburner)
	INTERNAL COMBUSTION ENGINE CONTROL
69	Catalyzed Diesel Particulate Filter
70	Non-Cat. Diesel Part. Filter w/ Active Regeneration
71	Diesel Oxidation Catalyst
72	Oxidation Catalyst
	INCINERATOR (See Afterburner)
	KNOCK-OUT POT (See Liquid Separator)
	LIQUID SEPARATOR
29	Knock-out Pot
30	Mist Eliminator, Horizontal Pad, Dry
31	Mist Eliminator, Panel, Dry
32	Mist Eliminator, Spray/Irrigated
33	Mist Eliminator, Vertical Tube, Dry
34	Mist Eliminator, Other
35	Other
	MIST ELIMINATOR (See Liquid Separator)

(revised: 9/05)

Code	DEVICE
	NO_X CONTROL
66	Selective Catalytic Reduction (SCR)
67	Non-Selective Catalytic Reduction (NSCR)
73	Selective Non-Catalytic Reduction (SNCR)
	SCRUBBER
36	Baffle and Secondary Flow
37	Centrifugal
38	Cyclone, Irrigated
39	Fibrous Packed
40	Impingement Plate
41	Impingement and Entrainment
42	Mechanically Aided
43	Moving Bed
44	Packed Bed
45	Preformed Spray
46	Venturi
47	Other
	SETTLING CHAMBER (See Dry Inertial Collector)
	SULFUR DIOXIDE CONTROL
48	Absorption and Regeneration, for Sulfur Plant
49	Claus Solution Reaction, for Sulfur Plant
50	Dual Absorption, for H2S04 Plant
51	Flue Gas Desulfurization, for Fossil Fuel Combustion
52	Reduction and Solution Regeneration, for Sulfur Plant
53	Reduction and Stretford Process, for Sulfur Plant
54	Sodium Sulfite-Bisulfite Scrubber, for H2S04 Plant
55	Other
	VAPOR RECOVERY
56	Adsorption, Activated Carbon/Charcoal
57	Adsorption, Silica
58	Adsorption, Other
59	Balance
60	Compression/Condensation/Absorption
61	Compression/Refrigeration
62	Condenser, Water-Cooled
63	Condenser, Other
64	Other
	MISCELLANEOUS
65	Not classified above

**BASIS CODES

Code	Method
0	Not applicable for this pollutant
1	Source testing or other measurement **by plant**
2	Source testing or other measurement **by BAAQMD**
3	Specifications from vendor
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance **by BAAQMD** using engineering expertise and knowledge of process
6	Taken from AP-42 ("Compilation of Air Pollutant Emission Factors," EPA)
7	Taken from literature, other than AP-42
8	Guess

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Mirant Marsh Landing, LLC Plant No: ______ (If unknown, leave blank)

2. Name or Description CO Catalyst System Abatement Device No: A- 5

3. Make, Model, and Rated Capacity TBD

4. Abatement Device Code (See table*) 2 Date of Initial Operation ______

5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 3 **S-** ______ **S-** ______ **S-** ______ **S-** ______
S- ______ **A-** ______ **A-** ______ **A-** ______ **A-** ______ **A-** ______

6. Typical gas stream temperature at inlet: 750 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics	< 2 ppmvd@15%O2	
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide	< 3 ppmvd@15%O2	
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ______ **A-** 6 ______ **A-** ______ **A-** ______ **P-** 3 **P-** ______

Person completing this form: Mark Strehlow Date: June 19, 2008

P:www\FormA (revised: 7/99)

*ABATEMENT DEVICE CODES

Code	DEVICE
	ADSORBER (See Vapor Recovery)
	AFTERBURNER
1	CO Boiler
2	Catalytic
3	Direct Flame
4	Flare
5	Furnace-firebox
6	Other
	BAGHOUSE (See Dry Filter)
	CYCLONE (See Dry Inertial Collector and Scrubber)
	DUST CONTROL
68	Water Spray
	DRY FILTER
7	Absolute
8	Baghouse, Pulse Jet
9	Baghouse, Reverse Air
10	Baghouse, Reverse Jet
11	Baghouse, Shaking
12	Baghouse, Simple
13	Baghouse, Other
14	Envelope
15	Moving Belt
16	Other
	DRY INERTIAL COLLECTOR
17	Cyclone, Dynamic
18	Cyclone, Multiple (12 inches dia. or more)
19	Cyclone, Multiple (less than 12 inches dia.)
20	Cyclone, Simple
21	Settling Chamber, Baffled/Louvered
22	Settling Chamber, Simple
23	Other
	ELECTROSTATIC PRECIPITATOR
24	Single Stage
25	Single Stage, Wet
26	Two Stage
27	Two Stage, Wet
28	Other
	INCINERATOR (See Afterburner)
	INTERNAL COMBUSTION ENGINE CONTROL
69	Catalyzed Diesel Particulate Filter
70	Non-Cat. Diesel Part. Filter w/ Active Regeneration
71	Diesel Oxidation Catalyst
72	Oxidation Catalyst
	INCINERATOR (See Afterburner)
	KNOCK-OUT POT (See Liquid Separator)
	LIQUID SEPARATOR
29	Knock-out Pot
30	Mist Eliminator, Horizontal Pad, Dry
31	Mist Eliminator, Panel, Dry
32	Mist Eliminator, Spray/Irrigated
33	Mist Eliminator, Vertical Tube, Dry
34	Mist Eliminator, Other
35	Other
	MIST ELIMINATOR (See Liquid Separator)

Code	DEVICE
	NO_X CONTROL
66	Selective Catalytic Reduction (SCR)
67	Non-Selective Catalytic Reduction (NSCR)
73	Selective Non-Catalytic Reduction (SNCR)
	SCRUBBER
36	Baffle and Secondary Flow
37	Centrifugal
38	Cyclone, Irrigated
39	Fibrous Packed
40	Impingement Plate
41	Impingement and Entrainment
42	Mechanically Aided
43	Moving Bed
44	Packed Bed
45	Preformed Spray
46	Venturi
47	Other
	SETTLING CHAMBER (See Dry Inertial Collector)
	SULFUR DIOXIDE CONTROL
48	Absorption and Regeneration, for Sulfur Plant
49	Claus Solution Reaction, for Sulfur Plant
50	Dual Absorption, for H2S04 Plant
51	Flue Gas Desulfurization, for Fossil Fuel Combustion
52	Reduction and Solution Regeneration, for Sulfur Plant
53	Reduction and Stretford Process, for Sulfur Plant
54	Sodium Sulfite-Bisulfite Scrubber, for H2S04 Plant
55	Other
	VAPOR RECOVERY
56	Adsorption, Activated Carbon/Charcoal
57	Adsorption, Silica
58	Adsorption, Other
59	Balance
60	Compression/Condensation/Absorption
61	Compression/Refrigeration
62	Condenser, Water-Cooled
63	Condenser, Other
64	Other
	MISCELLANEOUS
65	Not classified above

**BASIS CODES

Code	Method
0	Not applicable for this pollutant
1	Source testing or other measurement **by plant**
2	Source testing or other measurement **by BAAQMD**
3	Specifications from vendor
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance **by BAAQMD** using engineering expertise and knowledge of process
6	Taken from AP-42 ("Compilation of Air Pollutant Emission Factors," EPA)
7	Taken from literature, other than AP-42
8	Guess

(revised: 9/05)

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Mirant Marsh Landing, LLC   Plant No: ________
   (If unknown, leave blank)

2. Name or Description Selective Catalytic Reduction   Abatement Device No: A- 6

3. Make, Model, and Rated Capacity TBD

4. Abatement Device Code (See table*) 2   Date of Initial Operation ________

5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

   S- 3 **S-** ____ **S-** ____ **S-** ____ **S-** ____
   S- ____ **A-** 5 **A-** ____ **A-** ____ **A-** ____ **A-** ____

6. Typical gas stream temperature at inlet: 750 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics		
9.	Nitrogen Oxides (as NO_2)	2.5 ppmvd	
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

   S- ____ **A-** ____ ____ **A-** ____ **A-** ____ **P-** 3 **P-** ____

Person completing this form: Mark Strehlow   Date: June 19, 2008

P:www\FormA (revised: 7/99)

*ABATEMENT DEVICE CODES

Code	DEVICE
	ADSORBER (See Vapor Recovery)
	AFTERBURNER
1	CO Boiler
2	Catalytic
3	Direct Flame
4	Flare
5	Furnace-firebox
6	Other
	BAGHOUSE (See Dry Filter)
	CYCLONE (See Dry Inertial Collector and Scrubber)
	DUST CONTROL
68	Water Spray
	DRY FILTER
7	Absolute
8	Baghouse, Pulse Jet
9	Baghouse, Reverse Air
10	Baghouse, Reverse Jet
11	Baghouse, Shaking
12	Baghouse, Simple
13	Baghouse, Other
14	Envelope
15	Moving Belt
16	Other
	DRY INERTIAL COLLECTOR
17	Cyclone, Dynamic
18	Cyclone, Multiple (12 inches dia. or more)
19	Cyclone, Multiple (less than 12 inches dia.)
20	Cyclone, Simple
21	Settling Chamber, Baffled/Louvered
22	Settling Chamber, Simple
23	Other
	ELECTROSTATIC PRECIPITATOR
24	Single Stage
25	Single Stage, Wet
26	Two Stage
27	Two Stage, Wet
28	Other
	INCINERATOR (See Afterburner)
	INTERNAL COMBUSTION ENGINE CONTROL
69	Catalyzed Diesel Particulate Filter
70	Non-Cat. Diesel Part. Filter w/ Active Regeneration
71	Diesel Oxidation Catalyst
72	Oxidation Catalyst
	INCINERATOR (See Afterburner)
	KNOCK-OUT POT (See Liquid Separator)
	LIQUID SEPARATOR
29	Knock-out Pot
30	Mist Eliminator, Horizontal Pad, Dry
31	Mist Eliminator, Panel, Dry
32	Mist Eliminator, Spray/Irrigated
33	Mist Eliminator, Vertical Tube, Dry
34	Mist Eliminator, Other
35	Other
	MIST ELIMINATOR (See Liquid Separator)

Code	DEVICE
	NO_X CONTROL
66	Selective Catalytic Reduction (SCR)
67	Non-Selective Catalytic Reduction (NSCR)
73	Selective Non-Catalytic Reduction (SNCR)
	SCRUBBER
36	Baffle and Secondary Flow
37	Centrifugal
38	Cyclone, Irrigated
39	Fibrous Packed
40	Impingement Plate
41	Impingement and Entrainment
42	Mechanically Aided
43	Moving Bed
44	Packed Bed
45	Preformed Spray
46	Venturi
47	Other
	SETTLING CHAMBER (See Dry Inertial Collector)
	SULFUR DIOXIDE CONTROL
48	Absorption and Regeneration, for Sulfur Plant
49	Claus Solution Reaction, for Sulfur Plant
50	Dual Absorption, for H2S04 Plant
51	Flue Gas Desulfurization, for Fossil Fuel Combustion
52	Reduction and Solution Regeneration, for Sulfur Plant
53	Reduction and Stretford Process, for Sulfur Plant
54	Sodium Sulfite-Bisulfite Scrubber, for H2S04 Plant
55	Other
	VAPOR RECOVERY
56	Adsorption, Activated Carbon/Charcoal
57	Adsorption, Silica
58	Adsorption, Other
59	Balance
60	Compression/Condensation/Absorption
61	Compression/Refrigeration
62	Condenser, Water-Cooled
63	Condenser, Other
64	Other
	MISCELLANEOUS
65	Not classified above

**BASIS CODES

Code	Method
0	Not applicable for this pollutant
1	Source testing or other measurement **by plant**
2	Source testing or other measurement **by BAAQMD**
3	Specifications from vendor
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance **by BAAQMD** using engineering expertise and knowledge of process
6	Taken from AP-42 ("Compilation of Air Pollutant Emission Factors," EPA)
7	Taken from literature, other than AP-42
8	Guess

(revised: 9/05)

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Mirant Marsh Landing, LLC Plant No: ____ (If unknown, leave blank)

2. Name or Description CO Catalyst System Abatement Device No: A- 7

3. Make, Model, and Rated Capacity TBD

4. Abatement Device Code (See table*) 2 Date of Initial Operation ____

5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 4 **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____

6. Typical gas stream temperature at inlet: 750 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics	< 2 ppmvd@15%O2	
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide	< 3 ppmvd@15%O2	
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ **A-** 8 ____ **A-** ____ **A-** ____ **P-** 4 **P-** ____

Person completing this form: Mark Strehlow	Date: June 19, 2008

*ABATEMENT DEVICE CODES

Code	DEVICE
	ADSORBER (See Vapor Recovery)
	AFTERBURNER
1	CO Boiler
2	Catalytic
3	Direct Flame
4	Flare
5	Furnace-firebox
6	Other
	BAGHOUSE (See Dry Filter)
	CYCLONE (See Dry Inertial Collector and Scrubber)
	DUST CONTROL
68	Water Spray
	DRY FILTER
7	Absolute
8	Baghouse, Pulse Jet
9	Baghouse, Reverse Air
10	Baghouse, Reverse Jet
11	Baghouse, Shaking
12	Baghouse, Simple
13	Baghouse, Other
14	Envelope
15	Moving Belt
16	Other
	DRY INERTIAL COLLECTOR
17	Cyclone, Dynamic
18	Cyclone, Multiple (12 inches dia. or more)
19	Cyclone, Multiple (less than 12 inches dia.)
20	Cyclone, Simple
21	Settling Chamber, Baffled/Louvered
22	Settling Chamber, Simple
23	Other
	ELECTROSTATIC PRECIPITATOR
24	Single Stage
25	Single Stage, Wet
26	Two Stage
27	Two Stage, Wet
28	Other
	INCINERATOR (See Afterburner)
	INTERNAL COMBUSTION ENGINE CONTROL
69	Catalyzed Diesel Particulate Filter
70	Non-Cat. Diesel Part. Filter w/ Active Regeneration
71	Diesel Oxidation Catalyst
72	Oxidation Catalyst
	INCINERATOR (See Afterburner)
	KNOCK-OUT POT (See Liquid Separator)
	LIQUID SEPARATOR
29	Knock-out Pot
30	Mist Eliminator, Horizontal Pad, Dry
31	Mist Eliminator, Panel, Dry
32	Mist Eliminator, Spray/Irrigated
33	Mist Eliminator, Vertical Tube, Dry
34	Mist Eliminator, Other
35	Other
	MIST ELIMINATOR (See Liquid Separator)

Code	DEVICE
	NO_X CONTROL
66	Selective Catalytic Reduction (SCR)
67	Non-Selective Catalytic Reduction (NSCR)
73	Selective Non-Catalytic Reduction (SNCR)
	SCRUBBER
36	Baffle and Secondary Flow
37	Centrifugal
38	Cyclone, Irrigated
39	Fibrous Packed
40	Impingement Plate
41	Impingement and Entrainment
42	Mechanically Aided
43	Moving Bed
44	Packed Bed
45	Preformed Spray
46	Venturi
47	Other
	SETTLING CHAMBER (See Dry Inertial Collector)
	SULFUR DIOXIDE CONTROL
48	Absorption and Regeneration, for Sulfur Plant
49	Claus Solution Reaction, for Sulfur Plant
50	Dual Absorption, for H2S04 Plant
51	Flue Gas Desulfurization, for Fossil Fuel Combustion
52	Reduction and Solution Regeneration, for Sulfur Plant
53	Reduction and Stretford Process, for Sulfur Plant
54	Sodium Sulfite-Bisulfite Scrubber, for H2S04 Plant
55	Other
	VAPOR RECOVERY
56	Adsorption, Activated Carbon/Charcoal
57	Adsorption, Silica
58	Adsorption, Other
59	Balance
60	Compression/Condensation/Absorption
61	Compression/Refrigeration
62	Condenser, Water-Cooled
63	Condenser, Other
64	Other
	MISCELLANEOUS
65	Not classified above

**BASIS CODES

Code	Method
0	Not applicable for this pollutant
1	Source testing or other measurement **by plant**
2	Source testing or other measurement **by BAAQMD**
3	Specifications from vendor
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance **by BAAQMD** using engineering expertise and knowledge of process
6	Taken from AP-42 ("Compilation of Air Pollutant Emission Factors," EPA)
7	Taken from literature, other than AP-42
8	Guess

(revised: 9/05)

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Mirant Marsh Landing, LLC Plant No: ____
(If unknown, leave blank)

2. Name or Description Selective Catalytic Reduction Abatement Device No: A- 8

3. Make, Model, and Rated Capacity TBD

4. Abatement Device Code (See table*) 2 Date of Initial Operation ____

5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 4 **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** 7 **A-** ____ **A-** ____ **A-** ____ **A-** ____

6. Typical gas stream temperature at inlet: 750 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics		
9.	Nitrogen Oxides (as NO_2)	2.5 ppmvd	
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ **A-** ____ ____ **A-** ____ **A-** ____ **P-** 4 **P-** ____

Person completing this form: Mark Strehlow	Date: June 19, 2008

P:www\FormA (revised: 7/99)

*ABATEMENT DEVICE CODES

Code	DEVICE
	ADSORBER (See Vapor Recovery)
	AFTERBURNER
1	CO Boiler
2	Catalytic
3	Direct Flame
4	Flare
5	Furnace-firebox
6	Other
	BAGHOUSE (See Dry Filter)
	CYCLONE (See Dry Inertial Collector and Scrubber)
	DUST CONTROL
68	Water Spray
	DRY FILTER
7	Absolute
8	Baghouse, Pulse Jet
9	Baghouse, Reverse Air
10	Baghouse, Reverse Jet
11	Baghouse, Shaking
12	Baghouse, Simple
13	Baghouse, Other
14	Envelope
15	Moving Belt
16	Other
	DRY INERTIAL COLLECTOR
17	Cyclone, Dynamic
18	Cyclone, Multiple (12 inches dia. or more)
19	Cyclone, Multiple (less than 12 inches dia.)
20	Cyclone, Simple
21	Settling Chamber, Baffled/Louvered
22	Settling Chamber, Simple
23	Other
	ELECTROSTATIC PRECIPITATOR
24	Single Stage
25	Single Stage, Wet
26	Two Stage
27	Two Stage, Wet
28	Other
	INCINERATOR (See Afterburner)
	INTERNAL COMBUSTION ENGINE CONTROL
69	Catalyzed Diesel Particulate Filter
70	Non-Cat. Diesel Part. Filter w/ Active Regeneration
71	Diesel Oxidation Catalyst
72	Oxidation Catalyst
	INCINERATOR (See Afterburner)
	KNOCK-OUT POT (See Liquid Separator)
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Code	DEVICE
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50	Dual Absorption, for H2S04 Plant
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52	Reduction and Solution Regeneration, for Sulfur Plant
53	Reduction and Stretford Process, for Sulfur Plant
54	Sodium Sulfite-Bisulfite Scrubber, for H2S04 Plant
55	Other
	VAPOR RECOVERY
56	Adsorption, Activated Carbon/Charcoal
57	Adsorption, Silica
58	Adsorption, Other
59	Balance
60	Compression/Condensation/Absorption
61	Compression/Refrigeration
62	Condenser, Water-Cooled
63	Condenser, Other
64	Other
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**BASIS CODES

Code	Method
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8	Guess

(revised: 9/05)

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Mirant Marsh Landing, LLC Plant No: ____

Emission Point No: P- 1

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 1 **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** 1 **A-** 2 **A-** ____ **A-** ____ **A-** ____

Exit cross-section area: 357.15 sq. ft. Height above grade: 150.5 ft.

Effluent Flow from Stack

	Typical Operating Condition	***Maximum Operating Condition***
Actual Wet Gas Flowrate	1,378,149 cfm	1,397,371 cfm
Percent Water Vapor	8.5 Vol %	14.9 Vol %
Temperature	340 °F	338 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☒ yes ☐ no

What pollutants are monitored? NO_x, CO, O_2

Person completing this form Mark Strehlow Date June 19, 2008

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Mirant Marsh Landing, LLC Plant No: ______

Emission Point No: P- 2

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 2 **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** 3 **A-** 4 **A-** ____ **A-** ____ **A-** ____

Exit cross-section area: 357.15 sq. ft. Height above grade: 150.5 ft.

Effluent Flow from Stack

	Typical Operating Condition	***Maximum Operating Condition***
Actual Wet Gas Flowrate	1,378,149 cfm	1,397,371 cfm
Percent Water Vapor	8.5 Vol %	14.9 Vol %
Temperature	340 °F	338 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☒ yes ☐ no

What pollutants are monitored? NO_x, CO, O_2

Person completing this form Mark Strehlow Date June 19, 2008

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Mirant Marsh Landing, LLC Plant No: ____________

Emission Point No: P- 3

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 3 **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** 5 **A-** 6 **A-** ____ **A-** ____ **A-** ____

Exit cross-section area: 770.53 sq. ft. Height above grade: 150.25 ft.

Effluent Flow from Stack

	Typical Operating Condition	***Maximum Operating Condition***
Actual Wet Gas Flowrate	3,159,287 cfm	3,048,718 cfm
Percent Water Vapor	8.32 Vol %	8.9 Vol %
Temperature	750 °F	750 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☒ yes ☐ no

What pollutants are monitored? NO_x, CO, O_2

Person completing this form Mark Strehlow Date June 19, 2008

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Mirant Marsh Landing, LLC Plant No: ______

Emission Point No: P- 4

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 4 **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** 7 **A-** 8 **A-** ____ **A-** ____ **A-** ____

Exit cross-section area: 770.53 sq. ft. Height above grade: 150.25 ft.

Effluent Flow from Stack

	Typical Operating Condition	***Maximum Operating Condition***
Actual Wet Gas Flowrate	3,159,287 cfm	3,048,718 cfm
Percent Water Vapor	8.32 Vol %	8.9 Vol %
Temperature	750 °F	750 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☒ yes ☐ no

What pollutants are monitored? NO_x, CO, O_2

Person completing this form Mark Strehlow Date June 19, 2008

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Mirant Marsh Landing, LLC Plant No: ____________

Emission Point No: P- 5

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 5 **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____

Exit cross-section area: 0.35 sq. ft. Height above grade: 26 ft.

Effluent Flow from Stack

	Typical Operating Condition	***Maximum Operating Condition***
Actual Wet Gas Flowrate	1,048 cfm	1,048, cfm
Percent Water Vapor	Vol %	Vol %
Temperature	415 °F	415 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☒ no

What pollutants are monitored? ____________________

Person completing this form Mark Strehlow Date June 19, 2008

DATA FORM P Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Mirant Marsh Landing, LLC Plant No: ______

Emission Point No: P- 6

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 6 **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____

Exit cross-section area: 0.35 sq. ft. Height above grade: 26 ft.

Effluent Flow from Stack

	Typical Operating Condition	***Maximum Operating Condition***
Actual Wet Gas Flowrate	1,048 cfm	1,048, cfm
Percent Water Vapor	Vol %	Vol %
Temperature	415 °F	415 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☒ no

What pollutants are monitored? ______

Person completing this form Mark Strehlow Date June 19, 2008