NORTH COAST UNIFIED AIR QUALITY MANAGEMENT DISTRICT

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FINAL DETERMINATION OF COMPLIANCE

AUTHORITY TO CONSTRUCT EVALUATION

THE HUMBOLDT BAY REPOWERING PROJECT

APPLICATION #: ATC 440-1; HBRP
EVALUATION DATE: March 31, 2008
EVALUATION BY: NCUAQMD Staff

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FACILITY NAME

Pacific Gas & Electric Company, Humboldt Bay Repower Project (HBRP)

LOCATION OF EQUIPMENT

The project is located within a 143-acre site at 1000 King Salmon Ave, 3 miles southwest of the city of Eureka. It will be sited within the boundaries of PG&E's existing Humboldt Bay Power Plant complex.

PROPOSAL

Pacific Gas & Electric Company (PG&E) is proposing to install a 163 MW nominal power plant consisting of ten 16.3 MW nominal dual-fuel fired reciprocating engines.

INTRODUCTION

The plant will consist of ten Wärtsilä 18V50DF16.3 MW lean-burn reciprocating engines, equipped with selective catalytic reduction (SCR), oxidation catalyst, and associated support equipment including continuous emissions monitors. The primary fuel will be natural gas with diesel pilot injection, and the backup fuel will be diesel. The applicant will also install a diesel-fired emergency back-up generator and a diesel-fired fire pump. PG&E has identified and will be providing offsets for the project.

The District issued a Preliminary Determination of Compliance on October 24th 2007 and accepted public comment for 30 days pursuant to Rule 110 §8.4 through §8.6. After consideration of all comments received, the Air Pollution Control Officer has issued a Final Determination of Compliance (FDOC) pursuant to District Rule 110 §9.6. Toward that end, this engineering evaluation is meant to serve as a technical review document for the FDOC, and as the basis for the issuance of the Authority to Construct Permit for the project. The FDOC has been forwarded to the Commissioners of the California Energy Commission (CEC).

PG&E currently operates a natural gas and fuel oil power plant on the same property as the proposed repower project. The existing plant consists of 2 steam turbine-generators, 52 and 53 MW, respectively, primarily fueled by natural gas, with No. 6 fuel oil used as a secondary fuel; and 2 mobile emergency power plants (MEPPs), consisting of diesel-fueled turbines that operate as backup units and peaker units. A non-operating 63 MW nuclear power plant also exists at the facility. The 52 MW boiler began operating in 1956 and the 53 MW boiler began operating in 1953. (AFC Section 1.0, pg. 1-1)

PG&E proposes to decommission the existing power plant and replace it with the ten 16.3 MW Wärtsilä reciprocating engines described above. The new engines will be subject to Best Available Control Technology (BACT) requirements as well as Prevention of Significant Deterioration (PSD).

Equipment Operating Scenarios

As a commercial power plant, market circumstances and demand will dictate the exact operation of the new reciprocating engines. The following general operating modes are projected to occur.

Base Load – The facility would be operated at maximum continuous output for as many hours per year as scheduled by load dispatch, and limited by operational constraints of the permit to operate

(75% annual capacity factor). Normal operation of the plant will occur while the reciprocating engines are fired on natural gas with a diesel pilot: Firing on natural gas with diesel pilot is defined as "Natural Gas Mode" in the Authority to Construct (ATC) permit.

Load Following – The facility would be operated to meet variable load requirements. The generation would be adjusted periodically to the load demand primarily by increasing or decreasing the number of reciprocating engine units in operation; and secondarily by raising or lowering the output of an individual reciprocating engine. Due to the modular nature of the project configuration, partial shutdown of the engine group will occur at certain times of any given day during any given year. This mode of operation could generally be expected during late evening and early morning hours when system demand may be low. As additional generating capacity becomes available in the foreseeable future, more frequent operation in this mode is anticipated. Several alternative energy projects have recently been proposed for the area which will compliment the modular design of this project.

Full Shutdown – This would occur if forced by equipment malfunction, fuel supply interruption, transmission line disconnect, natural disaster, or market conditions. The project would be the primary source of power generation for the north coast region for the next several years. As such, full shutdown for any length of time is not anticipated.

Secondary Fuel – The project is to be located in a geographically isolated region along the northern coast of California. The area is prone to severe seismic activity and inclement weather. Because the single natural gas pipeline which services the area is highly susceptible to damage, reliance upon the single pipeline as a fuel source during natural disasters has been deemed inadequate by the California Independent System Operator. The applicant has proposed liquid fuel as a backup for the project as a solution. The facility is also subject to periodic curtailment of the natural gas supply. In such a circumstance, the reciprocating engines may be fired on liquid fuel. The engines have the capability of switching fuel types without interruption to power generation. The number of hours of liquid fuel firing is limited by the ATC permit to a maximum of 1000 operating hours per year total for all of the engine units combined.

Operation of the reciprocating engines while fired on 100% liquid fuel is defined as "Diesel Mode" in the ATC permit. The allowable liquid fuel types are specified in the ATC and are limited to CARB Diesel, CARB Diesel with additives, and Alternative Liquid Fuel. The emission calculations for the ATC permit were based upon emissions from CARB Diesel. The ATC permit will be conditioned to allow the use of CARB Diesel, and will be conditioned so as to prohibit the use of liquid fuel meeting the definition of the other two allowable fuel types, unless the applicant can demonstrate to the satisfaction of the APCO, that the use of CARB Diesel with Additives or an Alternative Liquid Fuel, will not result in a change in the facility's emission profile.

EQUIPMENT DESCRIPTION

The HBRP project will have the following equipment.

1. Ten Dual-fuel Reciprocating Engine-Generators (AFC Table 8.1-10)

Manufacturer:	Wärtsilä
Model:	18V50DF
Primary Fuel:	Natural Gas (Public Utilities Commission Pipeline Quality)
Backup Fuel:	CARB Diesel (ultra low sulfur, as defined in CCR Title

17, Section 93115)

2. Emergency Diesel Generator (AFC Table 8.1-12)

Manufacturer:	Caterpillar (or equivalent)
Model:	DM8149 (or equivalent)
Fuel:	CARB Diesel

3. Emergency Diesel Fire Pump (AFC Table 8.1-13 & Appendix 8.1A-5)

Manufacturer:	John Deere
Model:	JU6H-UF50
Fuel:	CARB Diesel

PROCESS RATE

1. Ten Dual-fuel Reciprocating Engine-Generators (AFC Table 8.1-10)

Nominal Heat Input Rate (HHV): (Higher Heating Value)	143.9 MMBtu/hr natural gas + 0.79 MMBtu/hr diesel pilot 148.9 MMBtu/hr diesel
Nominal Power Generation Rate:	16 MW
Maximum Continuous Brake Horsepower:	22,931 bhp
Nominal Exhaust Temperature:	728 degrees F
Exhaust Flow Rate (natural gas):	121,502 acfm
Exhaust Flow Rate (natural gas):	45,533 dscfm
Exhaust Flow Rate (diesel):	135,556 acfm
Exhaust Flow Rate (diesel):	54,078 dscf
Exhaust O2 Concentration, dry volume:	11.58%
Exhaust CO_2 Concentration, dry volume:	5.32%
Exhaust Moisture Content, wet volume:	9.42%
Engine Efficiency (Natural Gas):	47.3%
Engine Efficiency (Diesel):	44.0%
Exhaust Stack Height:	30.48 m
Exhaust Stack Diameter:	1.620 m

2. Emergency Diesel Generator (AFC Table 8.1-12 & Appendix Table 8.1A-4)

Engine Output (kW):	350
Engine Output (bhp):	469
Heat Input, MMBtu/hr (HHV):	4.0
Fuel Consumption, Btu/bhp-hr (HHV):	8,491
Fuel Input (gal/hr):	29.1
Exhaust Flow (acfm):	3366
Stack Velocity (ft/sec):	285.67
Temperature (˚F):	925.9
Stack Diameter (inch):	6
Release Height (m):	3.048
Operating hours/year, maintenance & Testing:	50

3. Emergency Diesel Fire Pump (AFC Table 8.1-13 & Appendix 8.1A-5)

Engine Output (bhp):	210
Speed (rpm):	2100
Heat Input, MMBtu/hr (HHV):	8,019
Fuel Input (gal/hr)	12.3
Capacity (gpm):	2500
Exhaust Flow (acfm):	1204
Stack Velocity (ft/sec):	13.7
Temperature (˚F):	1050
Stack Diameter (inch):	5
Release Height (m):	12.192
Operating hours/year, maintenance & Testing:	50

OPERATING SCHEDULE

Table 1 – Hours of Operation (AFC Appendix Table 8.1A-7)

Equipment	Hrs/day	Hrs/yr
ICE, NG, Base load hrs/engine	21	6132
ICE, NG, Startups/engine (3 startups/day max)	3	315
TOTAL NG Mode/engine	**24**	**6447**
ICE, Diesel, Base load hrs/engine	21	50
ECE, Diesel, Startups/engine (3 startup/day max)	3	50
TOTAL DIESEL Mode /engine	**24**	**100**
Emergency Generator[a)]	1	50
Fire Pump[a)]	1	50

Note: a) Includes testing & maintenance.

In order to ensure that the Wärtsilä engines are not operated in excess of the proposed 74.7% capacity factor (6,547 full-load engine hours per year – 70% Natural Gas and 5% Diesel), the permit will be conditioned to limit the combined heat input for all the Wärtsilä engines on an hourly, daily, and annual basis (AFC 8.1.2.2.2, pg 8.1-24, and 8.1.2.3, pg 8.1-26). Compliance with the 24 hour $PM_{2.5}$ AAQS while in Diesel Mode will be achieved by establishing the combined daily fuel usage limitation at 221,876 gallons (204 full load engine hours).

To ensure enforceability of the annual and daily capacity factors, in addition to the heat input limitations, the Wärtsilä engines will be limited to the following volumetric fuel consumption limits**.**

Table 2 – Combined Fuel Use Limitations for 10 Wärtsilä Engines

FUEL USE LIMITATIONS (gallons)[a, b]		
	Natural Gas Mode (Diesel Pilot)	Diesel Mode
Hourly (3-hr rolling average)	58	10,876
Daily	1,402	221,876
Annual (365-day rolling average)	376,734	1,087,630

a. Daily and annual heat rates for natural gas and diesel pilot injection are based on hours in AFC Appendix Table 8.1A-6 and higher heating value in AFC Table 8.1-11A

b. Daily and annual heat rates for backup diesel are based on hours in AFC Appendix Table 8.1A-7 and higher heating value in AFC Table 8.1-11B

The units have the capability of switching between fuel modes either through a startup - shutdown sequence or “cold start”; or through a process called “fuel switching” where one fuel type is gradually substituted for the other while horse power output is maintained. There are significant differences in the types and quantities of pollutants emitted when either natural gas or diesel is combusted. Thus, it will be necessary to precisely determine the quantity of fuel burned and the number of minutes the engines are operated in each mode. Accordingly, the hourly and daily emission limitations for Diesel Mode go into effect when the heat input from diesel fuel exceeds 0.8 MMBTU/hr for greater than one minute during any Clock Hour. To demonstrate compliance, each operating minute shall be designated as either “Natural Gas Mode” or “Diesel Mode” and records maintained. The sum of the operational minutes for all engines shall not exceed 1000 hrs per year; and shall not exceed 50 hours per engine for maintenance and testing purposes. A Fuel Switch will not be considered operation in transient mode because the unit’s air pollution control equipment will remain fully active throughout the event.

CONTROL EQUIPMENT EVALUATION

WÄRTSILÄ ENGINES

The engines will use selective catalytic reduction (SCR) to control nitrogen oxide emissions to a level of 6.0 ppmvd when operating on natural gas, and 35.0 ppmvd when operating in diesel mode, both @ 15% O_2 for a three-hour average. Carbon monoxide emissions are proposed to be controlled with oxidation catalysts to a level of 13.0 ppmvd when operating on natural gas, and 20.0 ppmvd when operating on diesel, both @ 15% O_2 for a three-hour average. Particulate matter created as a result of diesel fuel combustion is proposed to be controlled with oxidation catalysts to 7.56 lbs per hour which equates to approximately 30% reduction efficiency.

The nominal exhaust gas temperature is 728 degrees F (AFC Table 8.1-10 Design Specs). AFC Appendix Table 8.1B-3 identifies the max exhaust gas temp at approximately 795 F (697.4 K). The highest exhaust gas temperature at the catalyst is 840 degrees F.

EMISSIONS CALCULATIONS

The proposed project will replace the existing power plant, including 2 steam boilers (Units 1 and 2) and two Mobile Emergency Power Plants (MEPPs Units 2 and 3), permitted under NCUAQMD Permit numbers NS-020 (Boiler #1), NS-021 (Boiler #2), and NS-057 (Gas Turbines). The units are also permitted under Title V Permit to Operate No. NCU-059-12.

Potential to Emit

Table 3 – Emission Rates

WÄRTSILÄ ENGINES

Natural Gas Firing with Diesel Pilot Injection

NOX		Rate	Source
Base load, hourly	3.13	lb/hr	Calculation, based on manufacturer's guarantee of 6.0 ppmvd @ 15% O2 and 120,764 acfm (cold ambient temperature, base load)
Startup	23.6	lb/hr	Provided by manufacturer, 30-min start + 30 min base load. 22 lb/start

Diesel Firing

NOX		Rate	Source
Base load, hourly	19.92	lb/hr	Calculation, based on manufacturer's guarantee of 35.0 ppmvd @ 15% O2 and 134,544 acfm hot ambient temperature, base load)
Startup	164	lb/hr	Provided by manufacturer, 30-min start + 30 min base load. 154 lb/start

Natural Gas Firing with Diesel Pilot Injection

SO2		Rate	Source
Base load, hourly	0.40	lb/hr	Calculation, based on 1 gr. sulfur/100 scf and 143.9 MMbtu/hr (cold ambient temperature, base load)
Startup	0.20	lb/start	30-min start, hourly emission rate = base load hourly emission
Hourly rate for annual emissions	0.13	lb/hr	Based on annual average sulfur content of 0.33 gr/100 scf ---> 0.066 lb/hr + diesel sulfur from pilot injection ---> 0.0012 lb/hr.

Diesel Firing

SO2		Rate	Source
Base load, hourly	0.22	lb/hr	Calculation, based on 15 ppmw sulfur content and 148.9 MMbtu/hr hot ambient temperature, base load)

Startup	0.11	lb/start	30-min start, hourly emission rate = base load hourly emission

Natural Gas Firing with Diesel Pilot Injection

CO		Rate	Source
Base load, hourly	4.13	lb/hr	Calculation, based on manufacturer's guarantee of 13.0 ppmvd @ 15% O2 and 120,764 acfm (cold ambient temperature, base load)
Startup	24	lb/start	Provided by manufacturer, 30-min start + 30 min base load

Diesel Firing

CO		Rate	Source
Base load, hourly	6.93	lb/hr	Calculation, based on manufacturer's guarantee of 20.0 ppmvd @ 15% O2 and 134,544 acfm hot ambient temperature, base load)
Startup	25.4	lb/start	Provided by manufacturer, 30-min start + 30 min base load

Natural Gas Firing with Diesel Pilot Injection

ROC		Rate	Source
Base load, hourly	5.10	lb/hr	Calculation, based on manufacturer's guarantee of 28 ppmvd @ 15% O2 and 120,764 acfm (cold ambient temperature, base load)
Startup	17.9	lb/start	Provided by manufacturer, 30-min start + 30 min base load

Diesel Firing

ROC		Rate	Source
Base load, hourly	7.94	lb/hr	Calculation, based on manufacturer's guarantee of 40 ppmvd @ 15% O2 and 134,544 acfm hot ambient temperature, base load)
Startup	17.2	lb/start	Provided by manufacturer, 30-min start + 30 min base load

Natural Gas Firing with Diesel Pilot Injection

PM10		Rate	Source
Base load, hourly	3.60	lb/hr	Provided by manufacturer
Grain-loading	0.02	gr/dscf	Provided by manufacturer (hot ambient temperature, low load)
Startup	2.45	lb/start	30-min start, hourly emission rate = base load hourly emission

Diesel Firing

PM10		Rate	Source
Base load, hourly	7.56	lb/hr	Calculation, based on manufacturer's guarantee of 40 ppmvd @ 15% O2 and 134,544 acfm hot ambient temperature, base load) with 30% control from oxidation catalyst
Filterable PM10	0.11	g/bhp-hr	Provided by manufacturer, AFC pg 8.1-70, weighted average of emissions at 100%, 75%, and 50% loads
Startup	5.4	lb/start	30-min start, hourly emission rate = base load hourly emission

Natural Gas Firing with Diesel Pilot Injection

NH3		Rate	Source
Base load, hourly	1.93	lb/hr	Calculation, based on manufacturer's guarantee of 10.0 ppmvd @ 15% O2 and 120,764 acfm (cold ambient temperature, base load)

Diesel Firing

NH3		Rate	Source
Base load, hourly	2.11	lb/hr	Calculation, based on manufacturer's guarantee of 10.0 ppmvd @ 15% O2 and 134,544 acfm hot ambient temperature, base load)

BLACK-START GENERATOR

NOX	3.59	lb/hr	Provided by manufacturer
SO2	0.0061	lb/hr	Provided by manufacturer
CO	0.65	lb/hr	Provided by manufacturer
ROC	0.41	lb/hr	Provided by manufacturer
PM10	0.05	lb/hr	Provided by manufacturer

FIRE PUMP

NOX	2.27	lb/hr	Provided by manufacturer
SO2	0.0026	lb/hr	Provided by manufacturer
CO	0.27	lb/hr	Provided by manufacturer
ROC	0.23	lb/hr	Provided by manufacturer
PM10	0.06	lb/hr	Provided by manufacturer

The applicant considered multiple electrical generating technologies before making the final selection. The Wärtsilä 18V50DF internal combustion engine generators were chosen because they were best suited to meet the specific base and intermediate load power supply needs of the north coast region. The multi-unit configuration allows for modular operation thereby allowing the applicant to operate as many generating sets as required for optimal efficiency to follow existing load demand. The plant can be operated efficiently anywhere between 5% load (one generator set) up to 100% (all ten engines) in either Natural Gas or Diesel Mode. The applicant has identified the basis for, and has requested be incorporated into the operating permit, sufficient flexibility to enable the facility to match the load demands of the region while remaining in compliance with air quality regulations.

In order to identify the maximum allowable operational impacts associated with the facility, the applicant modeled a series of impacts which could occur during various operating scenarios. The Tables that follow reflect the emissions associated with various operating scenarios and are based upon varying types and numbers of equipment units being operated during any given hour, the fuel mode (Diesel or Natural Gas) being used, and the number of Startup and Shutdown Periods. The permit to operate will be conditioned so as to limit operation of the engines as necessary in order to ensure that a violation of the National Ambient Air Quality Standards (NAAQS), or a violation of the California Ambient Air Quality Standards will not occur as a result of operation of the devices under permit.

Table 4 – Hourly Emission Rates

MAXIMUM HOURLY EMISSION RATES (lb/hr)							
	NOX	CO	ROC	$SO2^d$	PM_{10}	NH3	NH3 g/s
Wärtsilä NG							
Base load	3.13	4.13	5.10	0.40	3.6	1.93	
Startup[a]	23.6	24.07	17.9	0.40	3.6	1.93	
Startup for all 10 engines	**392[b]**	**240.7**	**179.0**	**4.03**	**36.00**	**19.30**	
Wärtsilä Diesel							
Base load[c]	19.92	6.93	7.94	0.219	7.56[e]	2.11	2.659E-01
Startup[a]	164.0	25.46	17.2	0.219	7.56[f]	2.11	
Startup for all 10 engines	**392[b]**	**254.6**	**172**	**2.19**	**75.6**	**21.1**	
Black-Start Generator[a]	3.47	0.63	0.4	0.0061	0.05	0	
Fire Pump[a]	2.27	0.27	0.23	0.0026	0.06	0	

a - AFC Appendix Tables 8.1A-5 and A-6
b – max rate based upon modeling to determine compliance with NOx AAQS
c - front& back half (AFC Table 8.1-15)
d - SOX emissions are the same during startup and base load operations (AFC pg 8.1-29)
e- max rate based on modeling to determine compliance with PM2.5 AAQS w/ catalyst 30% reduction
f- 30 min startup + 30 min operation w/o catalyst

Operation of the engines in both natural gas and diesel modes during startup, shutdown, and maintenance and testing, must be limited in order to ensure compliance with the one hour ambient air quality standard for NOx. The value of 392 lbs/hr is equivalent to an emission rate of 7.34 g/sec per engine for 30 minutes and 2.47 g/sec for 30 minutes [Startup Period]. Engine operational constraints in addition to data collected from Continuous Emission Monitors (CEMs) will be used to demonstrate compliance with the facility wide NOx limit. Of the numerous possible combinations of engine operation possible, one was selected to represent maximum thresholds of operation in compliance with the NAAQS. Based upon the manufacturer's guaranteed emission date provided by the applicant, only two starts in diesel mode are possible during any one clock hour.

PM_{10} is the pollutant which limits the number of allowable hours of operation. As discussed below, only 204 engine hours are available when assuming a 7.56 lb per hour emission rate.

Table 5.1 Facility Operation During Diesel Mode

Maximum Allowable Daily Emission Rate (lb/day)							
	hours/day	NOX	CO	ROC	SO2	PM10	NH3
Wärtsilä Diesel							
Base load	21	418.32	145.53	166.74	8.4[a]	134.95	44.31
Startup	3	492	76.38	51.6	1.2[a]	19.29	6.33
TOTAL As Designed per Engine		**910.3**	**221.91**	**218.34**	**9.6**	**154.2**	**50.6**
TOTAL Allowable (10 Engines)	24	**9103**	**2219.1**	**2183.4**	**96.0**	**1542**	**506.4**
Black-Start Generator	0.75	2.69	0.5	0.31	0.005	0.04	0
Fire Pump	1	2.27	0.3	0.23	0.0026	0.06	0
	TOTALS	9108	2220	2184	96.1	2592.1	506.4

Note: a) SO2 values are the maximum allowed under Natural Gas Mode

The emission limits listed in Table 5.1 apply during any calendar day in which any of the reciprocating engines are fired in Diesel Mode for any length of time. The maximum allowable particulate emission rate per day for the entire facility is 1,542 pounds with a maximum emission rate of 1.22 g/sec. The basis of the limit is compliance with the 24-hour average $PM_{2.5}$ standard. It is reasonable to assume that the engines will be able to comply with the limit based upon the following assumptions: 30% PM control from the oxidation catalyst, and a limitation to 85% average daily load factor.

$$10.8\ lbs\ per\ hour * (1 - .3) * 0.85 * 10\ engines * 24\ hours\ per\ day = 1{,}542\ lbs\ per\ day$$

The permit will be conditioned so as to limit hourly emissions to 7.56 lbs per hour and at a maximum average load capacity of 85% for all 10 engines in diesel mode. Conditions limiting the 24 hour heat input capacity and fuel usage as a combination of all 10 engines will be included.

$$\frac{(1{,}542\ lbs\ PM\ per\ day)}{(7.56\ lbs\ per\ hour\ per\ engine)} * 85\%\ Load = 204\ engine\ hours\ per\ day$$

$$204\ engine\ hours\ per\ day * 1087.63\ gallons\ diesel\ per\ hour = 221{,}876\ gallons\ per\ day$$

$$221{,}876\ gallons\ per\ day * 136{,}903\ Btu\ per\ gallon = 30{,}375.5\ MMBtu\ per\ day$$

The worst case scenario identified during operation of the engines exclusively in Natural Gas Mode consists of 21 hours of operation at base load with 3 Startup Periods. In order to ensure compliance with ambient air quality standards, the permit will be conditioned to limit daily emissions to no more that the values identified in Table 5.2. The permit will be conditioned such that on calendar days when S-1 through S-10 are fired exclusively on natural gas, that the maximum allowable hours of operation in startup mode shall not exceed 30 hours as a combination of all 10 engines.

Table 5.2 Facility Operation During Natural Gas Mode Exclusively

Maximum Allowable Daily Emission Rate (lb/day)							
	hours/day	NOx	CO	ROC	SO2	PM_{10}	NH3
Wärtsilä Natural Gas Mode							
Base load	21	3.1	4.1	5.1	0.4	3.6	1.9
Startup	3	23.6	24.1	17.9	0.4	3.6	1.9
TOTAL As Designed per engine	24	135.9	158.4	160.8	9.6	86.4	45.6
Total Allowable 10 engines	240	1360	1589	1608	97	864	456

Note: In order to ensure compliance with the one hour NOx NAAQS, the maximum hourly emissions from the facility shall not exceed 1,360 lbs per day.

Of the several operating scenarios modeled, operation at loads below 75% (12 MW) for longer than 8 hours was not evaluated. A condition prohibiting operation at lower than 12 MW for greater than 80 engine hours per day will be included in the permit.

In order to ensure compliance with the hourly, daily, and annual emission limits, the permit shall be conditioned so as to limit the hours of operation as follows:

Table 5.3 Limitation on Hours of Operation

Equipment	Limit	Requirement / Basis	Permit Condition(s)
S-1 through S-10 Startup & Shutdown	"Startup Period" limited to 60 minutes	NAAQS / Modeling AFC 8.1.2.3.1	132
S-1 through S-10 Startup & Shutdown	30 hrs. per day (all engines combined)	NAAQS / Modeling AFC 8.1.2.3.3	134
S-1 through S-10 Startup & Shutdown	3,650 hrs. per year (all engines combined)	NAAQS / Modeling AFC 8.1.2.3.3	135
S-1 through S-10 Operation below 12.0 MW	80 hrs per day (all engines combined)	NAAQS/Modeling (not modeled)	137
S-1 through S-10 – Diesel Mode	Maintenance & Testing. 50 hrs/yr	Stationary Diesel ATCM	138.b
S-1 through S-10 – Diesel Mode	1000 hrs (all engines combined)	Health Risk Assessment	138.c
Emergency Generator & Fire Pump	Maintenance & Testing. 50 hrs/yr	Stationary Diesel ATCM	142
Emergency Generator & Fire Pump	No testing to occur during same day	NAAQS / Modeling AFC 8.1.2.3.3	143
Emergency Generator	No more than 45 minutes in any one hour	NAAQS / Modeling AFC 8.1.2.3.3	145
Emergency Generator & Fire Pump	No simultaneous operation with S-1 through S-10 in diesel mode	NAAQS / Modeling AFC 8.1.2.3.3	144

Commissioning Period

The existing Humboldt Bay Power Plant is the primary source of electrical generation for the north coast region. As such, it must remain in operation during the construction and commissioning periods of the replacement units. As stated in the in Section 8.1.2.7.6 Engine Commissioning of the AFC, the commissioning period begins when the engines are prepared for first fire and ends upon successful completion of initial performance testing. Before installation of the SCR and oxidation catalysts, the engines must be tuned to optimize performance and then tested to ensure compliance with emission standards. The number of hours the engines will be allowed to operate without emission controls will be limited in order to ensure compliance with the Ambient Air Quality Standards: the pollutants of concern being NOx, CO, and PM_{10}. The Permittee will submit a Commissioning Plan to the District which will be subject to review and approval by the APCO prior to installation and operation of equipment at the facility. The plan will detail SCR and oxidation catalyst optimization, and the tuning, alignment, and emission testing schedule. The estimated emissions from the simultaneous commissioning of 5 engines are found in Tables 5.4 through 5.7 below. The potential ambient impacts during commissioning are listed in Table 5.8.

Table 5.4 Emissions During Commissioning Period (per engine)

Operating Mode	Hours of Operation per Engine	Activity Duration	Hours of Operation per Day in Mode	Average Engine Load %	Total Hourly Emissions (lbs/hr) for 5 Engines		
					NOx	CO	PM10
Test run and tuning	50	3	18	75	242.5	147.9	18.4
Alignment	4	1	4	100	323.3	197.2	24.5
SCR tuning on Diesel	8	1	8	75	71.7	25.0	40.5

Table 5.5 Maximum Modeled Impact During Commissioning (By Mode)

Operating Mode	NO_2 1-hr Ozone Limiting	CO 1-hr	CO 8-hr	PM_{10}
Test Run and Tuning	**104.0**	**396.3**	**184.8**	**4.4**
Alignment	**127.0**	**476.0**	**113.0**	**0.8**
SCR Tuning on Diesel	**31.3**	**68.6**	**31.6**	**3.5**

Table 5.6 Maximum Total Impact During Commissioning

Pollutant	Modeled Impact	Background	Total Impact	Limiting Standard
PM_{10}	14.0	72.2	86.2	50
$PM_{2.5}$	7.0	35.0	42.0	35
CO	1,242	3,250	4,492	23,000
NO_2	233.3	75.2	308.5	470

Table 5.7 S-1 through S-10 Combined Commissioning Emission Limits

Pollutant	Lbs/hr	Lbs/day
CO	197.2	2,662
NOx	323.3	4,365
PM_{10}	54	1,296
ROC (as Methane)	86.6	1,559
SOx (SO_2)	2.0	48.4

The permit will be conditioned to limit the simultaneous commissioning to no more than 5 engines at any one time, and operation of the engines to no more than 90 engine hours during any one Calendar Day, and to no more than 100 hours of operation per engine. The limits established in Table 5.7 are based upon 5 engines operating for 18 hours per day (except as noted) while operating in the modes identified below.

$147.9\ lbs\ per\ hour\ CO * 18\ hrs\ per\ day = 2{,}662$ Test and tune mode

$242.5\ lbs\ per\ hour\ NOx * 18\ hrs\ per\ day = 4{,}365$ Test and tune mode

$54\ lbs\ per\ hour\ PM * 24\ hrs\ per\ day = 1{,}296$ All Modes (Diesel Uncontrolled)

$86.6\ lbs\ per\ hour\ ROC * 18\ hrs\ per\ day = 1{,}559$ All Modes (Fuel Use Dependent)

$2.0\ lbs\ per\ hour\ SOx * 18\ hrs\ per\ day = 48.4$ All Modes (Fuel Use Dependent)

The hourly potential to emit is greatest during the “alignment” phase of the commissioning schedule. The permit will be conditioned to prohibit operation of the engines in alignment mode to no more than 13 hours per Calendar Day.

$$323.3\ lbs\ per\ hour\ NOx * 13\ hrs\ per\ day = 4{,}202.9\ lbs\ NOx$$

90 engines hours per day is derived based upon operation of 5 engines at 18 hrs per day. The limit of 100 hours per engine is the estimated maximum time necessary to properly commission each unit.

Table 5.8 Maximum Modeled Impact During Commissioning

Operating Mode	NO2 1-hr avg	CO 1-hr avg	CO 8-hr avg	PM10 24-hr avg
Test run and tuning	222.3	1,025	435.9	13.8
Alignment	233.3	1,247	266.2	3.7
SCR Tuning on liquid fuel	177.1	176.1	74.8	13.7

Emissions of Toxics

Table 6 – Toxics Emission Rates

TOXICS - emission rates used for HRA

Natural Gas Mode							
	Natural Gas		**Diesel Pilot**		**Gas + Diesel[e)]**		
	lb/MMscf[a]	**lb/hr[b]**	**lb/Mgal[c]**	**lb/hr[d]**	**max hourly g/s**	**annual avg (g/s/engine**	**g/s for 10 engines**
Acetaldehyde	5.29E-01	7.46E-02	3.47E-03	2.03E-08	9.393E-03	6.91E-04	**6.91E-03**
Acrolein	5.90E-02	8.31E-03	1.07E-03	6.25E-09	1.048E-03	7.71E-05	**7.71E-04**
Ammonia					2.659E-01	8.57E-01	**1.70E-01**
Benzene	2.18E-01	3.07E-02	1.01E-01	5.90E-07	3.871E-03	2.85E-04	**2.85E-03**
1,3 Butadiene	3.67E-01	5.17E-02	0.00E+00	0.00E+00	6.517E-03	4.79E-04	**4.79E-03**
Ethylbenzene	7.11E-02	1.00E-02	0.00E+00	0.00E+00	1.262E-03	9.29E-05	**9.29E-04**
Formaldehyde	2.36E+00	3.33E-01	1.32E-02	7.71E-08	4.191E-02	3.08E-03	**3.08E-02**
Hexane	1.13E+00	1.59E-01	0.00E+00	0.00E+00	2.006E-02	1.48E-03	**1.48E-02**
Napthalene	2.51E-02	3.54E-03	1.63E-02	9.52E-08	4.457E-04	3.28E-05	**3.28E-04**
PAHs							
Anthracene	1.19E-04	1.68E-05	1.79E-04	1.05E-09	2.113E-06	1.55E-07	**1.55E-06**
Benzo(a)anthracene	5.88E-05	8.29E-06	5.03E-05	2.94E-10	1.044E-06	7.68E-08	**7.68E-07**
Benzo(a)pyrene	2.70E-06	3.81E-07	1.81E-05	1.06E-10	4.796E-08	3.53E-09	**3.53E-08**
Benzo(b)fluoranthene	4.09E-05	5.76E-06	7.96E-05	4.65E-10	7.263E-07	5.34E-08	**5.34E-07**
Benzo(k)fluoranthene	7.83E-06	1.10E-06	1.56E-05	9.12E-11	1.390E-07	1.02E-08	**1.02E-07**
Chrysene	1.43E-05	2.02E-06	1.06E-04	6.19E-10	2.540E-07	1.87E-08	**1.87E-07**
Dibenz(a,h)anthracene	2.70E-06	3.81E-07	2.43E-05	1.42E-10	4.796E-08	3.53E-09	**3.53E-08**
Indeno(1,2,3-cd)pyrene	7.17E-06	1.01E-06	2.89E-05	1.69E-10	1.273E-07	9.37E-09	**9.37E-08**
Propylene	5.38E+00	7.58E-01	3.85E-01	2.25E-06	9.553E-02	7.03E-03	**7.03E-02**
Toluene	2.39E-01	3.37E-02	3.74E-02	2.19E-07	4.244E-03	3.12E-04	**3.12E-03**
Xylene	6.46E-01	9.10E-02	2.68E-02	1.57E-07	1.147E-02	8.44E-04	**8.44E-03**

a - Emission factors from OEHHA's CATEF Natural Gas ICE, SCC 20200202 (4S/Lean burn > 650 hp, no pollution control device), Mean Values (options are Max, Mean and Median), except Formaldehyde and Hexane

Natural gas formaldehyde emission rate provided by vendor - no test data available

Natural gas hexane emission rate is from AP42; not listed in CATEF

b - based on 6147 hr/yr, 143.9 MMBtu/hr, and 1021.1 Btu/scf

c - Emission factors from OEHHA's CATEF Diesel ICE, SCC 20200102 (lean burn, no pollution control device, industrial engine), Mean values

d - based on 0.8 MMBtu/hr, 136903 Btu/gal diesel

e - based on 6447 hours/yr

Toxic emission rates from the Wärtsilä engines, when running on diesel, are quantified as Diesel Particulate Matter (DPM). The same is true for the Black-start Generator and the Fire Pump.

DPM consists solely of filterable particulate and does not include the condensable particulate matter.

Diesel Particulate Emissions

Table 6.1 Diesel Particulate Emissions per Engine

	Emission Rate (g/bhp-hr)	Horsepower	lb/hr	Max g/s	Hours/yr[a]	Tons/yr	g/s
Wärtsilä	0.11	22931	5.560962	7.01E-01	100	2.8E-01	8.00E-03
Black-start Generator[b]		469	0.05	6.30E-03	50	1.25E-03	3.60E-05
Fire Pump[b]		210	0.06	7.56E-03	50	1.50E-03	4.31E-05

a - hours used for HRA submitted with the AFC; a subsequent HRA calculation was submitted upon request, showing the risk from operating the Wärtsilä diesel engines at 100 hr/yr/engine on secondary diesel fuel, with an annual emission rate of 2.78 tons for all 10 engines

b - lb/hr emission rates as submitted by applicant.

Both the CARB Stationary Diesel Internal Combustion Engine Airborne Toxic Control Measure (CARB Diesel ATCM) and the National Emission Standards for Hazardous Air Pollutants (NESHAP) Sub Part III are applicable to this project and both have combustion efficiency standards expressed in grams per brake horsepower per hour units (g/bhp-hr). The permit will be conditioned so as to limit emissions of Diesel particulate Matter (DPM) to no more than 5.56 lbs/hr per engine and 0.11 g/bhp-hr. Compliance shall be determined via performance of source testing in accordance with CARB Method 5 utilizing the mass value obtained from the "front half" – filterable portion of the catch only.

The operating hours used in the dispersion modeling and health risk assessment to estimate maximum potential impacts from the proposed project, tabulated by quarter, are found in Table 7 below. The permit will be conditioned so as to cap emissions to the levels identified through restrictions on how many hours equipment units are operated, what fuel mode they are operated in, and in what types of equipment can be operated simultaneously.

Hourly Operational Limits

Table 7 – Hourly Operational Limits

CUMULATIVE HOURS OF OPERATION[a]						
	Daily	**Quarter 1**	**Quarter 2**	**Quarter 3**	**Quarter 4**	**Annual Average**
Wärtsilä Natural Gas						
Base load	-	15,120	15,280	15,460	15,460	61,320
Startup	-	780	790	790	790	3,150
Wärtsilä Diesel						
Base load	210	13	13	12	12	50
Startup	30	12	12	13	13	50
Emergency Generator	1	12	12	13	13	50
Fire Pump	1	12	12	13	13	50

Note: a) The Wärtsilä hours are combined for all ten engines

AFC Table 8.1-17 indicates that only one of the two emergency units (black start generator and fire pump) will be started during the same hour. The permit will be conditioned so as to prohibit the startup of both emergency engines in the same 60-minutre period, when started for testing and maintenance purposes. AFC Table 8.1-24 indicates that the black start generator's hourly emissions are based on 45-minutes of operation in any 1 hour. The permit will be conditioned so as to prohibit the black start generator from operating more than 45 minutes in any 60-minute period.

Emissions from the proposed project, tabulated by quarter are found in Table 8 below.

Quarterly Emission Rates

Table 8 – Quarterly Emission Rates

MAXIMUM QUARTERLY EMISSIONS QUARTER 1			NOX			CO			ROC			SOX			PM10/2.5		
	hr/day	hr/qtr[a]	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr
Wärtsilä NG																	
Base load * 10 engines	21	1512	3.13	47325.6	23.7	4.13	62445.6	31.2	5.10	77112	38.6	0.40	6048	3.0	3.6	54432	27.2
Startup[b] * 10 engines	3	78	23.6	18408	9.2	24.07	18774.6	9.4	17.9	13962	7.0	0.40	312	0.2	3.6	2808	1.4
Wärtsilä Diesel																	
Base load * 10 engines	21	13	19.92	2589.6	1.3	6.93	900.9	0.5	7.94	1032.2	0.5	0.219	28.47	0.0	7.56	982.8	0.5
Startup[b] * 10 engines	3	12	164.0	19680	9.8	25.46	3055.2	1.5	17.2	2064	1.0	0.219	26.28	0.0	7.56	907.2	0.5
SUBTOTAL				88003.2	44.0		85176.3	42.6		94170.2	47.1		6414.75	3.2		59130	29.6
Emergency Generator	1	12	3.47	41.64	2.1E-02	0.63	7.56	3.8E-03	0.4	4.8	2.4E-03	0.0061	0.0732	3.7E-05	0.05	0.6	3.0E-04
Fire Pump	1	12	2.27	27.24	1.4E-02	0.27	3.24	1.6E-03	0.23	2.76	1.4E-03	0.0026	0.0312	1.6E-05	0.06	0.72	3.6E-04
TOTAL				88072.1	44.0		85187.1	42.6		94177.76	47.1		6414.85	3.2		59131.3	29.6

Assumptions: All startups are diesel (worst case emissions)
50 hr/yr testing & maintenance and 50 hrs base load for all diesel operations
all diesel testing/maintenance covered under 3 hr/day startup
90 days in quarter

a - provided by applicant (AFC Appendix Table 8.1A-6)

b - applicant proposes 830 lb/hr NOX limit during startup for all Wärtsilä engines combined

MAXIMUM QUARTERLY EMISSIONS QUARTER 2																	
			NOX			CO			ROC			SOX			PM10/2.5		
	hr/day	hr/qtr[a]	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr
Wärtsilä NG																	
Base load * 10 engines	21	1528	3.13	47826.4	23.9	4.13	63106.4	31.6	5.10	77928	39.0	0.40	6112	3.1	3.6	55008	27.5
Startup[b] * 10 engines	3	79	23.6	18644	9.3	24.07	19015.3	9.5	17.9	14141	7.1	0.40	316	0.2	3.6	2844	1.4
Wärtsilä Diesel							0	0.0		0	0.0		0	0.0		0	0.0
Base load * 10 engines		13	19.92	2589.6	1.3	6.93	900.9	0.5	7.94	1032.2	0.5	0.219	28.47	0.0	7.56	982.8	0.5
Startup[b] * 10 engines	3	12	164.0	19680	9.8	25.46	3055.2	1.5	17.2	2064	1.0	0.219	26.28	0.0	7.56	907.2	0.5
SUBTOTAL				**88740**	**44.4**		**86077.8**	**43.0**		**95165.2**	**47.6**		**6482.75**	**3.2**		**59742**	**29.9**
Emergency Generator	1	12	3.47	41.64	2.1E-02	0.63	7.56	3.8E-03	0.4	4.8	2.4E-03	0.0050	0.06	3.0E-05	0.05	0.6	3.0E-04
Fire Pump	1	12	2.27	27.24	1.4E-02	0.27	3.24	1.6E-03	0.23	2.76	1.4E-03	0.0026	0.0312	1.6E-05	0.06	0.72	3.6E-04
TOTAL				**88808.9**	**44.4**		**86088.6**	**43.0**		**95172.76**	**47.6**		**6482.84**	**3.2**		**59743.3**	**29.9**

Assumptions: All startups are diesel (worst case emissions)
50 hr/yr testing & maintenance & 50 hrs base load for all diesel operations
all diesel testing/maintenance covered under 3 hr/day startup
90 days in quarter

a - provided by applicant (AFC Appendix Table 8.1A-6)

b - applicant proposes 830 lb/hr NOX limit during startup for all Wärtsilä engines combined

MAXIMUM QUARTERLY EMISSIONS QUARTER 3																	
			NOX			CO			ROC			SOX			PM10/2.5		
	hr/day	hr/qtr[a]	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr
Wärtsilä NG																	
Base load * 10 engines	21	1546	3.13	48389.8	24.2	4.13	63849.8	31.9	5.10	78846	39.4	0.40	6184	3.1	3.6	55656	27.8
Startup[b] * 10 engines	3	79	23.6	18644	9.3	24.07	19015.3	9.5	17.9	14141	7.1	0.40	316	0.2	3.6	2844	1.4
Wärtsilä Diesel																	
Base load * 10 engines		12	19.92	2390.4	1.2	6.93	831.6	0.4	7.94	952.8	0.5	0.219	26.28	0.0	7.56	907.2	0.5
Startup[b] * 10 engines	3	13	164.0	21320	10.7	25.46	3309.8	1.7	17.2	2236	1.1	0.219	28.47	0.0	7.56	982.8	0.5
SUBTOTAL				**90744.2**	**45.4**		**87006.5**	**43.5**		**96175.8**	**48.1**		**6554.75**	**3.3**		**60390**	**30.2**
Emergency Generator	1	13	3.47	45.11	2.3E-02	0.63	8.19	4.1E-03	0.4	5.2	2.6E-03	0.0050	0.065	3.3E-05	0.05	0.65	3.3E-04
Fire Pump	1	13	2.27	29.51	1.5E-02	0.27	3.51	1.8E-03	0.23	2.99	1.5E-03	0.0026	0.0338	1.7E-05	0.06	0.78	3.9E-04
TOTAL				**90818.8**	**45.4**		**87018.2**	**43.5**		**96183.99**	**48.1**		**6554.849**	**3.3**		**60391.4**	**30.2**

Assumptions: All startups are diesel (worst case emissions)
50 hr/yr testing & maintenance and 50 hrs base load for all diesel operations
all diesel testing/maintenance covered under 3 hr/day startup
90 days in quarter

a - provided by applicant (AFC Appendix Table 8.1A-6)

b - applicant proposes 830 lb/hr NOX limit during startup for all Wärtsilä engines combined

MAXIMUM QUARTERLY EMISSIONS QUARTER 4																	
			NOX			CO			ROC			SOX			PM10/2.5		
	hr/day	hr/qtr[a]	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr	lb/hr	lb/qtr	ton/qtr
Wärtsilä NG																	
Base load * 10 engines	21	1546	3.13	48389.8	24.2	4.13	63849.8	31.9	5.10	78846	39.4	0.40	6184	3.1	3.6	55656	27.8
Startup[b] * 10 engines	3	79	23.6	18644	9.3	24.07	19015.3	9.5	17.9	14141	7.1	0.40	316	0.2	3.6	2844	1.4
Wärtsilä Diesel																	
Base load * 10 engines		12	19.92	2390.4	1.2	6.93	831.6	0.4	7.94	952.8	0.5	0.219	26.28	0.0	7.56	907.2	0.5
Startup[b] * 10 engines	3	13	164.0	21320	10.7	25.46	3309.8	1.7	17.2	2236	1.1	0.219	28.47	0.0	7.56	982.8	0.5
SUBTOTAL				**90744.2**	**45.4**		**87006.5**	**43.5**		**96175.8**	**48.1**		**6554.75**	**3.3**		**60390**	**30.2**
Emergency Generator	1	13	3.47	45.11	2.3E-02	0.63	8.19	4.1E-03	0.4	5.2	2.6E-03	0.0050	0.065	3.3E-05	0.05	0.65	3.3E-04
Fire Pump	1	13	2.27	29.51	1.5E-02	0.27	3.51	1.8E-03	0.23	2.99	1.5E-03	0.0026	0.0338	1.7E-05	0.06	0.78	3.9E-04
TOTAL				**90818.8**	**45.4**		**87018.2**	**43.5**		**96183.99**	**48.1**		**6554.849**	**3.3**		**60391.4**	**30.2**

Table 8.1 – Quarterly Emissions Summary

QUARTERLY EMISSIONS SUMMARY			
tons/qtr			
	NOX	ROC	PM10/2.5
Quarter 1	44.0	47.1	29.6
Quarter 2	44.4	47.6	29.9
Quarter 3	45.4	48.1	30.2
Quarter 4	45.4	48.1	30.2
Total	179.3	190.9	119.8

Annual Emission Rates

Table 9 – Annual Emission Rates

MAXIMUM ANNUAL EMISSIONS	NOX		CO		ROC		SO2		PM10		NH3	
	lb/yr	ton/yr	lb/yr	ton/yr	lb/yr	ton/yr	lb/yr	ton/yr	lb/yr	ton/yr	lb/yr	ton/yr
Wärtsilä NG												
Base load per engine	19,193.2	96.0	25,325.2	12.7	31,273.2	15.6	797.2	0.4	22,075.2	11.0	11,834.8	59.2
Startup per engine	7,434.0	37.2	7,582.1	3.8	5,638.5	2.8	41.0	0.0	1,134.0	0.6	608.0	3.0
Base load * 10 engines	191,931.6	96.0	253,251.6	126.6	312,732.0	156.4	7,971.6	4.0	220,752.0	110.4	118,347.6	591.7
Startup * 10 engines	74,340.0	37.2	75,820.5	37.9	56,385.0	28.2	409.5	0.2	11,340.0	5.7	6,079.5	30.4
Wärtsilä Diesel												
Base load per engine	996.0	0.5	346.5	0.2	397.0	0.2	11.0	0.0	378.0	0.2	105.5	0.1
Startup per engine	8,200.0	4.1	1,273.0	0.6	860.0	0.4	11.0	0.0	378.0	0.2	105.5	0.1
Base load * 10 engines	9,960.0	5.0	3,465.0	1.7	3,970.0	2.0	109.5	0.1	3,780.0	1.9	1,055.0	0.5
Startup * 10 engines	82,000.0	41.0	12,730.0	6.4	8,600.0	4.3	109.5	0.1	3,780.0	1.9	1,055.0	0.5
SUBTOTAL	**358,231.6**	**179.1**	**345,267.1**	**172.6**	**381,687.0**	**190.8**	**8,600.1**	**4.3**	**239,652.0**	**119.8**	**126,537.1**	**63.3**
Black-Start Generator	173.5	0.1	31.5	0.0	20.0	0.0	0.3	0.0	2.5	0.0	0.0	0.0
Fire Pump	113.5	0.1	13.5	0.0	11.5	0.0	0.1	0.0	3.0	0.0	0.0	0.0
TOTAL	**358,518.6**	**179.3**	**345,312.1**	**172.7**	**381,718.5**	**190.9**	**8,600.5**	**4.3**	**239,657.5**	**119.8**	**126,537.1**	**63.3**

based on 100 hr/yr/engine diesel firing total (5% capacity factor)
10 engines at 24 hr/day, 7 days/week
6,132 Wärtsilä engine hours at base load, natural gas firing (70% capacity factor)
315 hours of natural gas startup emissions
50 hours of diesel startup emissions
Black-Start Generator & Fire Pump = 50 hr/yr/engine

Emissions of NOx will be limited to a combined maximum of 392 lb/hr for all Wärtsilä engines. At a startup rate of 164 lb/hr during secondary diesel fuel startups, two diesel mode startups are possible in the same hour. The permit will be so conditioned as to limit startups to a maximum of 2 engines per 60 minute period.

Annual and quarterly emissions are based on 6,547 hours of operation per engine. Each engine may have up to 3 startups per day, but are limited to 365 hours per year of startup and shut-down activity, with 1 hour per event (AFC 8.1.2.3.3, pg 8.1-29, 30). The permit will be conditioned so as to limit each Wärtsilä engine to a maximum of 3 startups per 24-hour period.

Dispersion Model Emission Rates

Table 10 - DISPERSION MODEL EMISSION RATES

The applicant indentified a series of 10 equipment operating scenarios which could result in the maximum criteria pollutant emissions [AFC Appendix Table 8.1B-3]. A screening analysis was then performed in order to identify potential need for further evaluation. Compliance with the ambient air quality standards at the emission rates listed is shown in the tables below.

1- HOUR AVERAGE – Diesel Mode (g/s)					
	NOX	CO	SO2	PM10	PM2.5
Wärtsilä	2.504	0.871	2.764E-2	-	-
Black-Start Generator	-	-	-	-	-
Fire Pump	-	-	-	-	-

Basis: Scenario 5D as identified in AFC Appendix Table 8.1-B. Wärtsilä emission are the base load rate while in Diesel Mode. Since the black-start generator and the fire pump emissions were not modeled in this scenario, the permit will be conditioned so as to prohibit the operation of these two engines for testing and maintenance purposes while the Wärtsilä engines are operating on secondary diesel fuel.

1-HOUR AVERAGE – Natural Gas Mode (g/s)					
	NOX	CO	SO2	PM10	PM2.5
Wärtsilä	0.39437337	0.5203712	5.04E-02	-	-
Black-Start Generator	0.43721265	7.94E-02	7.69E-04	-	-
Fire Pump	0.28601519	3.40E-02	3.28E-04	-	-

Basis: Scenario 5G as identified in AFC Appendix Table 8.1-B. Wärtsilä emission rates are base load rates while in Natural Gas Mode.

3-HOUR AVERAGE - Natural Gas Mode (g/s)					
	NOX	CO	SO2	PM10	PM2.5
Wärtsilä	-	-	5.077E-02	-	-
Black-Start Generator	-	-	2.549E-04	-	-
Fire Pump	-	-	1.077E-04	-	-

Basis: Scenario 5G as identified in AFC Appendix Table 8.1-B. Wärtsilä emission rates are base load rates while in Natural Gas Mode.

8-HOUR AVERAGE - Diesel Mode (g/s)					
	NOX	CO	SO2	PM10	PM2.5
Wärtsilä	-	1.165	-	-	-
Black-Start Generator	-	1.026E-02	-	-	-
Fire Pump	-	4.302E-03	-	-	-

Basis: Scenario 5D as identified in AFC Appendix Table 8.1-B. Wärtsilä emissions are 7 hours at the base load rate and 1 one Startup Period while in Diesel Mode. Even though the black-start generator and the fire pump emissions were modeled in this scenario, the permit will be conditioned so as to prohibit the operation of these two engines for testing and maintenance purposes while the Wärtsilä engines are operating on secondary diesel fuel.

24-HOUR AVERAGE - Natural Gas Mode (g/s)					
	NOX	CO	SO2	PM10	PM2.5
Wärtsilä	-	-	-	4.536E-01	4.536E-01
Black-Start Generator	-	-	-	2.769E-04	2.769E-04
Fire Pump	-	-	-	3.403E-04	3.403E-04

Basis: Scenario 4G as identified in AFC Appendix Table 8.1-B. Wärtsilä emission rates are 21 hours at base load rates and 3 Startup Periods while in Natural Gas Mode.

24-HOUR AVERAGE – Diesel Mode (g/s)					
	NOX	CO	SO2	PM10	PM2.5
Wärtsilä	-	-	-	0.4818	0.4818
Black-Start Generator	-	-	-	-	-
Fire Pump	-	-	-	-	-

Basis: Scenario 4D as identified in AFC Appendix Table 8.1-B. Wärtsilä emission are the base load rate while in Diesel Mode. Since the black-start generator and the fire pump emissions were not modeled in this scenario, the permit will be conditioned so as to prohibit the operation of these two engines for testing and maintenance purposes while the Wärtsilä engines are operating on secondary diesel fuel.

24-HOUR AVERAGE - Natural Gas Mode (g/s)					
	NOX	CO	SO2	PM10	PM2.5
Wärtsilä	-	-	5.077E-02	-	-
Black-Start Generator	-	-	3.186E-05	-	-
Fire Pump	-	-	1.346E-05	-	-

Basis: Scenario 5G as identified in AFC Appendix Table 8.1-B. Wärtsilä emission rates are base load rates while in Natural Gas Mode.

ANNUAL AVERAGE – Modes Combined (g/s)					
	NOX	CO	SO2	PM10	PM2.5
Wärtsilä (per engine)	5.010E-01	-	1.260E-02	3.393E-01	3.393E-01
Black-Start Generator	2.581E-03	-	4.365E-06	3.794E-04	3.794E-04
Fire Pump	1.631E-03	-	1.844E-06	4.661E-04	4.661E-04

Basis: Scenario 1G as identified in AFC Appendix Table 8.1-B. Wärtsilä emission rates are based on: 1)10 engines at 24 hr/day, 7 days/week; 2) 6,132 hours at base load, natural gas firing (70% capacity factor); 3) 315 hours of natural gas startup emissions; 4) 50 hours of diesel startup emissions; 5) 50 hr/yr/engine diesel firing; and 6) Black-Start Generator & Fire Pump = 50 hr/yr/engine.

Calculation of BACT Triggers (NCUAQMD Rule 101 & Rule 110):

The HBRP meets the local and federal definition of a reconstructed source (NCUAQMD Regulation 1, Rule 110 §4.22; 40 CFR 60.15). According to Rule 110 Section 4.15, a reconstructed source shall be treated as a new source rather than a modified source; therefore the historical potential to emit is zero.

Table 12 - Each Wärtsilä Engine (uncontrolled)

Pollutant	Max Daily (lb/day)	BACT Trigger Levels (lb/day)	Max Annual (ton/yr)	BACT Trigger Levels (ton/yr)	Is BACT Required?
NOX	3,561.0	>50.0	3,184	≥ 40	Yes
CO	2,456.0	>500.0	3,511.7	≥ 100	Yes
ROC	782.6	>50.0	1,053.9	≥ 40	Yes
SOX	9.1	>80.0	12.8975.0	≥ 40	No
PM10/2.5	135.3	>80.0	158.2	≥ 15	Yes

Uncontrolled emissions are based on data provided by the applicant. The worst case operating scenario was selected for each pollutant. Emission rates reflect 50 hours per year per engine of diesel fuel firing for maintenance & testing purposes.

Table 13 - Emergency Black-Start Generator BACT Determination

Pollutant	Max Daily (lb/day)	BACT Trigger Levels (lb/day)	Max Annual (ton/yr)	BACT Trigger Levels (ton/yr)	Is BACT Required?
NOX	3.6	>50.0	0.1	≥ 40	No
CO	0.65	>500.0	0.01	≥ 100	No
ROC	0.41	>50.0	0.001	≥ 40	No
SOX	0.006	>80.0	0.0001	≥ 40	No
PM10/2.5	0.05	>80.0	0.001	≥10	No

Reflects 50 hr/yr testing and maintenance; does not include hours of operation during emergencies.

Table 14 - Emergency Fire Pump Generator BACT Determination

Pollutant	Max Daily (lb/day)	BACT Trigger Levels (lb/day)	Max Annual (ton/yr)	BACT Trigger Levels (ton/yr)	Is BACT Required?
NOX	2.3	>50.0	0.06	≥ 40	No
CO	0.3	>500.0	0.008	≥ 100	No
ROC	0.2	>50.0	0.005	≥ 40	No
SOX	0.003	>80.0	7.5 E-05	≥ 40	No
PM10/2.5	0.06	>80.0	0.0015	≥10	No

Reflects 50 hr/yr testing and maintenance; does not include hours of operation during emergencies.

Calculation of Offset Trigger

Calculation of offset trigger for NO_X, ROC, SO2 and PM10/2.5 (Rule 110, Section 5.2.1): Annual emissions depicted below reflect the worst case scenario, not including operations under natural gas curtailment.

Table 15 – Calculation of Offset Trigger

CALCULATION OF OFFSET TRIGGER FOR NOX, ROC AND PM10/2.5 (tons/yr)				
	NO_X	ROC	SO2	PM_{10}
Facility Wide Emissions	179.3	190.9	4.3	119.8
Offset Trigger	≥ 25	≥ 25	≥ 25	≥ 25

4. Calculation of emission offsets for NOX, ROC, SOX and PM10/2.5 (Section 415 and 416):

NO_X:
Since the cumulative emissions for the HBRP is in excess of the 25 tons/year offset trigger limit, emission offsets will be required for NO_X.

ROC:
Since the cumulative emissions for the HBRP is in excess of the 25 tons/year offset trigger limit, emission offsets will be required for ROC.

SO_2:
Since the cumulative emissions for the HBRP is less than the 25 tons/year offset trigger limit, emission offsets will not be required for SOx.

PM_{10} and $PM_{2.5}$:
Since the cumulative emissions for the HBRP is in excess of the 25 tons/year offset trigger limit, emission offsets will be required for PM_{10} and $PM_{2.5}$.

COMPLIANCE WITH RULES AND REGULATIONS

<u>California Health & Safety Code Section 42301.6:</u>

The HBRP will be constructed on a parcel of land which is in the vicinity of the South Bay Elementary School. The minimum distance between the property boundaries of the facility and of the elementary school was determined to be approximately 600 feet. The minimum distance between an HBRP project emission point (stack) and the property boundary of the elementary school is approximately 1650 feet. The District has determined the following for the purpose of determining compliance with CH&SC § 42301.6:

- The new sources (emission points) created as a result of the project, are the Wärtsilä engine exhaust stacks;
- The Wärtsilä engine exhaust stacks will be located greater than 1000 feet from the parcel boundary of real property owned or under the control of the South Bay Elementary School; and
- The Wärtsilä engine exhaust stacks will be located greater than 1320 feet (1/4 mile) from the parcel boundary of real property owned or under the control of the South Bay Elementary School.

Accordingly, the District has determined that the public noticing requirements of CH&SC §42301.6 do not apply to this project. It should be noted that this project has undergone extensive review by multiple public agencies, and that the products of the reviews have been made available to the public at numerous public workshops.

New Source Review & Prevention of Significant Deterioration

<u>Offsets Requirements (NCUAQMD Rule 110, Sections 1.2 & 5.2)</u>

> NCUAQMD Regulation I, Rule 110, Section 1.2: *No net increase in emissions…from new or modified stationary sources which emit, or have the potential to emit, 25 tons per year or more of any non-attainment pollutant or its precursors.*

The NCUAQMD is classified as non-attainment for the state PM_{10} standard. The precursors to PM_{10} include NO_X, ROC, and SO_2.

In addition to Regulation I, Rule 110, the NCUAQMD has a SIP-approved rule, and therefore permitting authority for federal New Source Review (NSR) and Prevention of Significant Deterioration (PSD). The NCUAQMD is in attainment of the federal Ambient Air Quality Standards. Consequently, PSD review is required for the proposed project. The applicant has proposed offsets for the above pollutants as described in Table 16 below.

The protocol used to determine HBRP emissions subject to offsets is as follows:

1. Determine if source is "new" or is a modification of an "existing" source.
2. Consult Table 8.1 Quarterly Emissions to identify the maximum emissions authorized.
3. Calculate net emission change and apply any credit according to Rule 110 §5.2.
4. If credit is available, 25 tpy / 4 quarters = 6.25 tons is then subtracted from each quarter.
5. Apply offset reductions after application of distance factor adjustment.
6. Apply onsite inter-pollutant reduction after application of adjustment factor.

The District has determined that the two years preceding the date of application to be representative of actual operations (October 2004 through September 2006) [AFC Table 8.1A-9] The applicant has identified Emission Reduction Certificate 07-098-12 as the source of offset ERCs. The permit will be conditioned to require the surrender of Emission Reduction Certificate 07-098-12 prior to the commencement of the Commissioning Period of reciprocating engines S-1 through S-10. In order to be considered an Actual Emission Reduction pursuant to Rule 110 §6, the permit will be conditioned to require the permanent shutdown of the existing facility.

Table 16 – Offset Package

NO_X	Tons				
	Q1	**Q2**	**Q3**	**Q4**	**Total**
HBRP Project Emissions	44.0	44.4	45.4	45.4	179.3
Emissions Not Subject to Offset	6.25	6.25	6.25	6.25	25.0
Credits Available (closure of existing facility)	192.2	212.2	220.5	267.6	892.5
Onsite NOx Reductions Used	37.8	38.2	39.2	39.2	154.3
Surplus Reduction Credits Available	154.4	174.0	181.3	228.4	738.2

ROC	Tons				
	Q1	**Q2**	**Q3**	**Q4**	**Total**
HBRP Emissions Subject to Offsets	47.1	47.6	48.1	48.1	190.9
Emissions Not Subject to Offset	6.25	6.25	6.25	6.25	25.0
Onsite ROC:ROC offsets(closure of existing facility)	5.3	5.4	6.1	6.6	23.4
Offsite ROC:ROC offsets **(ERC Certificate #07-098-12)**	0.41	0.39	0.39	0.39	1.6
Onsite NOx:ROC offsets	35.1	35.1	34.9	34.4	139.5
Balance	0	0	0	0	

Onsite NOx:ROC Ratio 1:1(Used)	35.1	35.1	34.9	34.4
Surplus NOx Credits Remaining	119.3	138.9	146.4	194.0

PM_{10}	Tons				
	Q1	Q2	Q3	Q4	Total
HBRP Emissions Subject to Offsets	29.6	29.9	30.2	30.2	119.9
Emissions Not Subject to Offset	0	0	0	0	0
Onsite PM:PM offsets	4.7	7.1	6.4	6.7	24.9
Offsite PM:PM2.5 offsets **(ERC Certificate #07-098-12)**	1.6	1.6	1.6	1.6	6.4
Onsite NOx:PM2.5 offsets	23.3	14.7	15.8	15.5	69.3
Balance	0	0	0	0	

	Q1	Q2	Q3	Q4
Onsite NOx:PM2.5 Ratio 3.58:1 (Used)	83.414	52.626	56.56	55.49
Surplus NOx Credits Remaining	35.9	86.3	89.9	138.6

ASSUMPTIONS

Onsite reductions are result of planned decommissioning of existing power plant
Existing power plant = 2 natural gas boilers & 2 diesel turbine peakers, all uncontrolled
allowed 25 tons per year emissions, as source meets definitions of "new"

all PM is PM2.5

Offset ratios

NOX:NOX	1:1
NOX:ROC	1:1
NOX:PM2.5	3.58:1
Offsite Adjustment Factor	1.5:1

Best Available Control Technology (BACT) (NCUAQMD Rule 110 §5.1)

Regulation I, Rule 110.5.1 requires that the applicant apply BACT to any new emissions unit which results in a potential to emit for the emissions unit which exceeds the thresholds set forth in NCUAQMD Rule 110 §5.1. Thus, the application of BACT to reciprocating engines S-1 through S-10 is required for NOx, CO, SOx, and PM_{10} (Tables 12 through 14).

Regulation 110 §4.5 defines BACT as the more stringent of:

a. The most effective emission control device, emission limit, or technique which has been required or used for the type of equipment comprising such emissions unit unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable; or

b. Any other emission control device or technique, alternative basic equipment, different fuel or process, determined to be technologically feasible and cost-effective by the APCO.

The applicant provided BACT analyses for NOx, ROC, CO, and PM_{10}. An evaluation of emissions control requirements was completed through a “top-down” BACT determination. The top-down approach to the BACT review process involved identifying all demonstrated and potentially applicable control technology alternatives. After broadly identifying potential control technology alternatives, the District independently evaluated the information submitted and eliminated control alternatives that are not technically feasible because the alternative was either not available or not applicable.

The proposed project consists of engines of a size and fuel firing technologies that are not directly comparable to other permitted emission units in the state of California. During the regulatory evaluation of the proposed project, a number of internal combustion engine units were considered. The in-state units evaluated were all single fuel engines, either diesel fuel fired or natural gas fired. Two out-of-state dual fuel plants were reviewed; one is located in Denver, CO and the other is in Chambersburg, PA. The out-of-state engines do not run on ultralow sulfur diesel. The engines in Colorado are 10% diesel fuel injection, whereas the proposed Wärtsilä engines use 0.7% diesel fuel injection. Additionally, a natural gas Wärtsilä engine power plant, located in Red Bluff, CA, was evaluated.

Nitrogen Oxides (NOx)

NOx is formed during the combustion of fossil fuels and is generally classified as either thermal NOx or fuel NOx. Thermal NOx is formed when elemental nitrogen reacts with oxygen in the combustion air. The rate of formation of thermal NOx is a function of residence time, temperature and free oxygen. Fuel NOx is generated when nitrogen contained in the fuel itself is oxidized. The rate of formation of fuel NOx is primarily a function of fuel-bound nitrogen content of the fuel, but is also affected by fuel air mixing.

NOx emissions can be reduced using three different strategies: controlling fuel nitrogen, using combustion controls, and exhaust gas treatment.

Emissions from fuel-bound nitrogen can be reduced by restricting the type of fuel burned and the nitrogen content of the fuel. Natural gas typically has no fuel-bound nitrogen. CARB ultra low sulfur diesel fuel is a low-nitrogen fuel. Diesel fuel emulsions are also known to reduce NOx emissions.

Combustion control options include after cooling, electronic fuel injection timing retard, exhaust gas recirculation, pre-chamber combustion ignition (clean burn combustion or pre-stratified charge combustion), turbo charging, water/steam injection and air-to-fuel ratio adjustment (lean burn/rich burn combustion).

Exhaust gas treatments include non-selective catalytic reduction, selective catalytic reduction and selective non-catalytic reduction.

A) Fuel restrictions

The applicant proposes to use utility-grade natural gas as the primary fuel and CARB ultra-low sulfur diesel as a back-up fuel, for periods of natural gas curtailment and emergency operations.

B) Combustion Controls

After Cooling: After cooling can result in NOx reductions from 3% to 35%. After cooling is technically feasible. Accordingly, the Wärtsilä engines will be so configured.

Exhaust Gas Recirculation (EGR): The applicant states that EGR would result in increased fouling of the air intake systems, combustion chamber deposits, and engine wear rates due to the chemical and physical properties of the exhaust gas. Additionally, this control technique is not commercially available from manufacturers of stationary internal combustion engines.

According to the 1997 publication by the Manufacturers of Emission Controls Association (MECA), *Emission Control Technology for Stationary Internal Combustion Engines*, “employing EGR to diesel engines introduces abrasive diesel particulate into the air intake which could result in increased engine wear and fouling. Using EGR after a diesel particulate filter would supply clean EGR and effectively eliminate this concern.”

The New Jersey *State of the Art Manual for Reciprocating Internal Combustion Engines*, 2003, states that EGR results in a 48% to 80% reduction in NOx emissions in stationary diesel engines.

According to a 2005 presentation by Caterpillar, Inc., “Concerns with EGR systems include how suppressing combustion by limiting oxygen concentrations affects engine performance and fuel efficiency, and whether combustion products in exhaust gases affect operation/maintenance costs and the service life of components. In some markets, such as standby power generation, these issues may not be critical.”

Independent research confirmed that EGR is not commonly used on stationary internal combustion engines; however, with the use of diesel particulate filters and ultra-low sulfur diesel, low-pressure EGR technology is being developed that could reduce NOx emissions by up to 80%, according to MECA testimony to the EPA, 2005.

Because the use of diesel particulate filters has been deemed technically infeasible for this project, in turn, the use of EGR is also not feasible.

Pre-chamber combustion: In pre-chamber combustion, fuel is delivered into a chamber off the combustion chamber, the “pre-chamber”, where combustion begins and then spreads into the main chamber. This is also known as indirect injection. The pre-chamber is carefully designed to ensure adequate mixing of the atomized fuel with the compression-heated air. The addition of a pre-chamber can increase heat loss to the cooling system and subsequently lower engine efficiency. Early diesel engines often used indirect injection. According to a major manufacturer of stationary diesel engines, indirect injection (IDI) fuel systems are available for diesel engines. Pre-chamber combustion can reduce NOx emissions by 80%.

The applicant states that pre-chamber combustion is technically infeasible because it cannot be used in conjunction with diesel fuel firing. An independent review found no evidence to the contrary.

Rich burn combustion: EPA estimates that rich burn combustion can reduce NOx by 90% to 98%. According to the applicant, "the ability to fire on gas or oil is a project requirement. There are no dual-fuel rich-burn engines available." An independent review found no evidence to the contrary.

Water/steam injection: According to the applicant, steam injection techniques applicable to boilers and turbines do in fact reduce peak combustion temperatures, and for these applications do realize a decrease in NOx emissions. However, water or steam would corrode the interior of internal combustion engines and downstream components, thereby increasing engine wear. Therefore, these techniques are considered to be technically infeasible for this application. A Wärtsilä publication indicates that water injection is a valid method of NOx control "only on liquid-fuel-fired diesel engines." Water/steam injection can reduce NOx emissions by 50% to 60%.

Due to the dual fuel capability and the configuration of the proposed engines, water/steam injection is determined to be technically infeasible.

Lean combustion: Lean combustion decreases the fuel/air ratio in the zones where NOx is formed. Thus, the peak temperature is lower and therefore thermal NOx formation is suppressed. The applicant has selected this technology for NOx reduction.

C. Exhaust Gas Treatment

Non-Selective Catalytic Reduction (NSCR): This technology uses three-way catalysts to promote the reduction of NO_X to nitrogen and water. CO and hydrocarbons are simultaneously oxidized to carbon dioxide and water. NSCR is applicable only to rich burn engines and is therefore not technically feasible for the proposed lean burn engines.

Selective Non-Catalytic Reduction (SNCR): SNCR is applicable to both lean burn natural gas and diesel engines. SNCR involves injecting ammonia or urea into regions of the exhaust with temperatures greater than 1400 – 1500 degrees Fahrenheit. The nitrogen oxides in the exhaust are reduced to nitrogen and water vapor. Additional fuel is required to heat the engine exhaust to the correct operating temperature. Heat recovery from the engine exhaust can limit the additional fuel requirement and concurrent additional emissions from heating exhaust gases. Ten parts per million ammonia (slip) is considered reasonable for SNCR. Temperature is the operational parameter affecting the reaction - as well as degree of contaminant mixing with reagent and residence time. Additional control of particulate matter (up to 85% diesel particulate matter), volatile organic compounds (up to 90 percent) and carbon monoxide (up to 70 percent) may be realized by the afterburning effect of this technology.

Given that the Wärtsilä engine design exhaust temperature is rated at 728 degrees Fahrenheit, this technology would not be technically feasible.

Selective Catalytic Reduction (SCR): SCR is a process that involves post-combustion removal of NO_X from exhaust gas with a catalytic reactor. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_X decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system.

The applicant proposes to use SCR for NO_X emissions control. The applicant provided the following information regarding the SCR system: "The SCR equipment will include a reactor chamber, catalyst modules, ammonia storage system, ammonia injection and mixing system and monitoring equipment and sensors."

The SCR process is subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is generally the result either of prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent condition. Catalyst suppliers typically only guarantee a limited lifetime to very low emission level, high performance catalyst systems. The permit will be conditioned so as to require the applicant to prepare an inspection and maintenance plan wherein replacement intervals for equipment are identified.

SCR manufacturers typically estimate 10 ppmvd of un-reacted ammonia emissions (ammonia slip) when making guarantees at very high efficiency levels. To achieve high NOx reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which conversely results in ammonia slip. Thus, an emissions trade-off between NOx and ammonia may occur in high NOx reduction applications.

The potential environmental impacts associated with the use of SCR include:

i. Un-reacted ammonia would be emitted to the atmosphere (ammonia slip).

ii. Ammonium particulate may be formed and potentially clog the catalyst.

iii. Safety issues and Risk Management Planning may be required relative to the transportation, handling, and storage of ammonia.

According to the 1997 publication by the Manufacturers of Emission Controls Association (MECA), *Emission Control Technology for Stationary Internal Combustion Engines*, SCR technologies can provide greater than 90% reduction in NO_X.

The following information sources were consulted to identify possible NO_X BACT limits for similar sizes and types of equipment:

1. CARB "Guidance for the Permitting of Electrical Generation Technologies"
2. NEO California Power LLC, Red Bluff, Tehama County Air Pollution Control District 2006 Source Test of natural gas-fired Wärtsilä engines at average

operating rate of 2.80 MW

3. Chambersburg, PA Orchard Park Generating Station; Wärtsilä dual-fuel, 5.6 MW engines permitted October 28, 2004.
4. South Coast Air Quality Management District BACT Guidelines Manual
5. Bay Area Air Quality Management District BACT Guidelines
6. CARB RACT/BACT/LAER Clearinghouse
7. Colorado La Junta Municipal Utilities

NEO California Power

NO_X (natural gas-fired reciprocating engines (3,871 bhp-hr) – achieved in practice	Engine 11: 4.86 ppmvd @ 15% O_2 Engine 9: 3.83 ppmvd @ 15% O_2 No other engines were tested

Bay Area Air Quality Management District BACT Guidelines

Natural Gas Lean Burn (NEO, Red Bluff; permitted limit)	0.07 g/bhp-hr (6 ppmvd @ 15% oxygen)
Diesel CI Engine >= 175 hp	107 ppmvd @ 15% O_2 (1.5 g/bhp-hr)

CARB “Guidance for Power Plant Siting and Best Available Control Technology”

NO_X (natural gas-fired reciprocating engines)	9.0 ppmvd @ 15% O_2
NO_X (diesel-fired reciprocating engines)	No data available

South Coast Air Quality Management District BACT Guidelines Manual

Orange County Flood Control District – Natural Gas – 750 bhp	0.15 g/bhp-hr
Snow Summit – Diesel - 2,835 bhp with SCR	50 ppmvd @ 15% O_2 permit limit 45 ppmvd @ 15% O2 achieved in practice

CARB RACT/BACT/LAER Clearinghouse

Natural Gas	1.5 g/bhp-hr
Diesel	4.17 g/bhp-hr

Orchard Park

Natural gas with diesel pilot injection	24 ppmv (4.5 lb/hr)
Diesel	130 ppmv (26.7 lb/hr)

La Junta

Natural gas with 10% diesel pilot injection	0.03 lb/MMBtu (2683 ppmvd @ 15% O_2)
Diesel	3.4 lb/MMbtu (25 ppmvd @ 15% O_2)

Eliminate Technically Infeasible Options
Rich Burn Combustion
Water Steam Injection
Non-Selective Catalytic Reduction
Selective Non-Catalytic Reduction

Remaining Technologies Ranked by % Control Efficiency
Selective Catalytic Reduction (>90%)
Exhaust Gas Recirculation (80%)
Pre-Chamber Combustion (80%)
Fuel Restrictions (35%)
After Cooling
Lean Burn Technology

Federal New Source Performance Standards (NSPS)
On July 11, 2006 USEPA adopted NSPS Subpart IIII. When fired on natural gas, the Wärtsilä engines are pilot ignition engines, not compression ignition engines, and are therefore not subject to the NSPS. The NSPS specifies a NOx limit of 1.2 gm/hp-hr which is equivalent to 120 ppm. The proposed BACT limits are 6.0 ppm during Natural Gas mode and 35 ppm during Diesel Mode.

Through the application of selective catalytic reduction (SCR) and lean burn technology, the applicant proposes to meet the NOx concentration limit of 6.0 ppmvd @15% O_2 (0.06 g/bhp-hr) during natural gas operation. During diesel operation, the applicant proposed to meet a limit 35.0 ppmvd @ 15% O_2 (0.39 g/bhp-hr). The applicant expects to be able to achieve an emission control efficiency of 97.3% when operating on natural gas, and 96.4% when firing diesel fuel. The permit will be conditioned so as to require compliance with the concentrations listed above for the fuel modes identified. Control efficiency limits will only be required for CO reduction.

Carbon Monoxide (CO)

A) Combustion Control

Carbon monoxide is formed as a result of incomplete combustion of a hydrocarbon fuel. Control of CO is accomplished by providing adequate fuel residence time, excess oxygen and high temperature in the combustion chamber to ensure complete combustion. These control factors, however, also tend to result in increased emissions of NO_X. Conversely, a low NO_X emission rate achieved through combustion modification techniques can result in higher levels of CO formation. Thus, a compromise is established to achieve the lowest NO_X formation rate possible while keeping CO emission rates at acceptable levels.

B) Exhaust Gas Treatment

<u>Oxidation Catalyst:</u> CO emissions can also be controlled by exhaust gas treatment. According to MECA, oxidation catalysts have been used on off-road mobile source lean-burn engines for almost 30 years. In the U.S., over 500 stationary lean-burn IC engines have been outfitted with oxidation catalysts. Oxidation catalysts contain precious metals impregnated onto a high geometric surface area carrier and are placed in the

exhaust stream. With the use of oxidation catalyst, CO emissions can be reduced by up to 90%. The applicant proposes to install oxidation catalysts on all the Wärtsilä engines.

The following information sources were consulted to identify possible CO BACT limits for similar sizes and types of equipment:

1. CARB "Guidance for the Permitting of Electrical Generation Technologies"
2. NEO California Power LLC, Red Bluff, Tehama County Air Pollution Control District 2006 Source Test of natural gas-fired Wärtsilä engines at average operating rate of 2.80 MW
3. Chambersburg, PA Orchard Park Generating Station; Wärtsilä dual-fuel, 5.6 MW engines permitted October 28, 2004.
4. South Coast Air Quality Management District BACT Guidelines Manual
5. Bay Area Air Quality Management District BACT Guidelines
6. CARB RACT/BACT/LAER Clearinghouse
7. Colorado La Junta Municipal Utilities

NEO California Power

Natural gas-fired reciprocating engines (3,871 bhp-hr) achieved in practice	Engine 11: 5.45 ppmvd @ 15% O_2 (0.03 g/bhp-hr) Engine 9: 42.26 ppmvd @ 15% O_2 (0.20 g/bhp-hr) No other engines were tested

South Coast Air Quality Management District BACT Guidelines Manual

Orange County Flood Control District – Natural Gas – 750 bhp	0.6 g/bhp-hr
Kings County – Diesel – 2848 bhp	.035 g/bhp-hr – 97% removal efficiency achieved
Snow Summit – Diesel - 2,835 bhp with SCR	89 ppmvd @ 15% O_2 permit limit 5 ppmvd @ 15% O_2 achieved

CARB RACT/BACT/LAER Clearinghouse

Natural Gas	0.6 g/bhp-hr
Diesel	89 ppmvd @ 15% O_2

Bay Area Air Quality Management District BACT Guidelines

Natural Gas Lean Burn (NEO, Red Bluff; permitted limit)	12 ppmvd @ 15% oxygen (0.10 g/bhp-hr)
Diesel CI Engine >= 175 hp	319 ppmvd @ 15% O2 (2.75 g/bhp-hr)

CARB "Guidance for Power Plant Siting and Best Available Control Technology"

Natural gas-fired reciprocating engines	56 ppmvd @ 15% O_2 (0.6 g/bhp-hr)
Diesel-fired reciprocating engines	No data available

Orchard Park

Natural gas with diesel pilot injection	No data available
Diesel	1.5 g/bhp-hr

Eliminate Technically Infeasible Options
None

Remaining Technologies Ranked by % Control Efficiency
Oxidation Catalyst (90%)
Combustion Controls

Federal National Emission Standards for Hazardous Air Pollutants (NESHAP)
The USEPA has adopted NESHAP Subpart ZZZZ which limits emissions of formaldehyde. When an oxidation catalyst is used to comply with the NESHAP, CO emissions must be reduced by 70%. Through the application of combustion controls and oxidation catalyst, the applicant proposes to meet a CO concentration limit of 13.0 ppmvd @15% O2 (0.08 g/bhp-hr) during natural gas operation. During diesel operation, the applicant proposed to meet a limit of 20.0 ppmvd @ 15% O2 (0.14 g/bhp-hr). The applicant expects to be able to achieve an emission control efficiency of 96.8% when operating on natural gas, and 88.9% when firing diesel fuel.

The applicant's proposed CO emission limits, based on vendor guarantee, are within range of the majority of the other emission units evaluated, with the diesel concentration of 13 ppmvd being one part per million greater than the Bay Area BACT limit of 12 and the NEO engine's best achieved of 5.45. The proposed limit of 0.08 g/bhp-hr is greater than the NEO achieved rate of 0.03. The diesel fuel emission limit of 20 ppmvd is greater than the Snow Summit achieved rate of 5 ppmvd; and the rate of 0.14 g/bhp-hr is greater than the King's County diesel engine BACT rate of 0.035.

Reactive Organic Compounds (ROC)

According to the US EPA, ROCs are discharged into the atmosphere from internal combustion engines when some of the fuel remains unburned or is only partially burned during the combustion process. Most ROC emissions result from fuel droplets that were transported or injected into the quench layer during combustion. This is the region immediately adjacent to the combustion chamber surfaces where heat transfer outward through the cylinder walls causes the mixture temperatures to be too low to support combustion. In the case of natural gas, some organics are carryover, un-reacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents.

ROC emissions can be controlled by combustion controls and exhaust gas treatment.

A) Combustion Control
<u>Combustion Control</u> refers to controlling emissions of ROC through the design and operation of the engine in a manner so as to limit VOC formation. In general, a combustion control system seeks to maintain the proper conditions to ensure complete combustion. The applicant stated that combustion control will be optimized for NOX reduction, but they will additionally have the effect of reducing ROC emissions.

B) Exhaust Gas Treatment

Oxidation catalysts generally are precious metal compounds that promote oxidation of CO and VOCs to CO_2 and H_2O in the presence of excess O_2. According to a report prepared for the EPA in 2002, CO and NMHC conversion levels of 98% to 99% are achievable. Methane conversion may approach 60 to 70%. The report also states that oxidation catalysts are now widely used with all types of engines, including diesel engines. They are being used increasingly with lean burn gas engines to reduce their relatively high CO and VOC emissions. The applicant will install oxidation catalysts on all the Wärtsilä engines.

The following information sources were consulted to identify possible ROC BACT limits for similar sizes and types of equipment:

1. CARB "Guidance for the Permitting of Electrical Generation Technologies"
2. NEO California Power LLC, Red Bluff, Tehama County Air Pollution Control District 2006 Source Test of natural gas-fired Wärtsilä engines at average operating rate of 2.80 MW
3. Chambersburg, PA Orchard Park Generating Station; Wärtsilä dual-fuel, 5.6 MW engines permitted October 28, 2004.
4. South Coast Air Quality Management District BACT Guidelines Manual
5. Bay Area Air Quality Management District BACT Guidelines
6. CARB RACT/BACT/LAER Clearinghouse
7. Colorado La Junta Municipal Utilities

NEO California Power

NMOC (natural gas-fired reciprocating engines (3,871 bhp-hr) achieved in practice	Engine 11: 7.49 ppmvd @ 15% O_2 (0.02 g/bhp-hr) Engine 9: 6.82 ppmvd @ 15% O_2 (0.02 g/bhp-hr) No other engines were tested

CARB "Guidance for Power plant Siting and Best Available Control Technology"

VOC (natural gas-fired reciprocating engines)	25 ppmvd @ 15% O_2 (0.15 g/bhp-hr)
VOC (diesel-fired reciprocating engines)	No data available

Bay Area Air Quality Management District BACT Guidelines

Natural Gas Lean Burn (NEO, Red Bluff; permitted limit)	32 ppmvd @ 15% oxygen (0.15 g/bhp-hr)
Diesel CI Engine >= 175 hp	62 ppmvd @ 15% O_2 (0.30 g/bhp-hr) 309 ppmvd @ 15% O_2 (1.5 g/bhp-hr) achieved

South Coast Air Quality Management District BACT Guidelines Manual

Orange County Flood Control District – Natural Gas – 750 bhp	0.15 g/bhp-hr
Kings County – Diesel – 2848 bhp	.0026 g/bhp-hr – 95% removal efficiency achieved

Snow Summit – Diesel - 2,835 bhp with SCR	39 ppmvd @ 15% O_2 (0.15 g/bhp-hr) permit limit 49 (NMHC) ppmvd @ 15% O_2 (0.21 g/bhp-hr) achieved 25% hydrocarbon removal guarantee

CARB RACT/BACT/LAER Clearinghouse

Natural Gas	0.15 g/bhp-hr
Diesel	39 ppmvd @ 15% O_2

Orchard Park

Natural gas with diesel pilot injection	No data available
Diesel	0.75 g/bhp-hr

Eliminate Technically Infeasible Options
None

Remaining Technologies
Oxidation Catalyst
Combustion Controls

Through the application of combustion controls and oxidation catalyst, the applicant proposes to meet a ROC concentration limit of 28 ppmvd @15% O2 (0.1 g/bhp-hr) during natural gas operation. During diesel operation, the applicant proposed to meet a limit of 40.0 ppmvd @ 15% O2 (0.16 g/bhp-hr). The applicant expects to be able to achieve an emission control efficiency of 86.7% when operating on natural gas, and 77.8% when firing diesel fuel.

The applicant's proposed VOC emission limits, based on vendor guarantee, are within range of the other emission units evaluated, with the diesel concentration of 40.0 ppmvd being one part per million greater than the CARB BACT limit of 39.

Particulate Matter (PM)
Particulate matter emissions from internal combustion engines are considered to be 2.5 microns or smaller in diameter ($PM_{2.5}$). They are evaluated as PM which is directly emitted and as PM which occurs due to secondary formation with other compounds in the atmosphere. Natural gas combustion will comprise only a small fraction of the direct PM emissions; the majority of direct PM emissions being created by diesel pilot injection (during natural gas operation) and from firing solely on diesel during diesel mode. Conversely, the NOx generated during natural gas combustion will the majority of the PM created as a result of secondary formation of PM in the atmosphere.

The California Air Resources Board regulates diesel particulate matter (DPM) as a toxic air contaminant. DPM consists of the filterable portion of total particulate emitted from diesel combustion sources.

Particulate emissions from internal combustion engines can be controlled by exhaust gas treatment methods.

A) Diesel Particulate Filters (DPF)
Historically, stationary diesel engines used for both primary and back-up power generation have been installed with DPF systems to control particulate emissions. Information on the application of DPFs to stationary diesel engines can be found in the California Air Resources Board staff report issued in September 2003 to support ARB's air toxic control measure aimed at reducing particulate emissions from these engines (ARB staff report available at: www.arb.ca.gov/regact/statde/statde.htm). This report includes lists of DPF applications and reports on operating experience on stationary engines, for example, Caterpillar 3516 engines, rated in the 1490-2120 kW range. ARB did not identify operating experience with engines of the size range proposed for this project (approximately 16,000 kW); however, ARB did not indicate that the technology is not transferable to the larger engines.

DPFs can be passive or active. When ultra-low sulfur diesel fuel (<15 ppm sulfur) is used, precious metal catalyst-based diesel particulate filters (CB-DPFs) have demonstrated the capability to reduce PM emissions on a mass basis by up to 90 percent or more. CB-DPF technology has also demonstrated the capability to reduce a wide range of toxic hydrocarbon compounds by up to 80 percent or more. While developing the New Source Performance Standard for Compression Ignition engines, the EPA concluded that DPFs were not feasible for engines with a displacement greater than 30 liters per cylinder.

DPF's are currently commercially available. However, upon review of the CARB BACT Clearing House, staff could not locate an installation of a DPF on an engine of similar design and capacity. The installation most similar appears to be located in Kings County and has a capacity of 2848 bhp (SCAQMD BACT registry). This unit had 6 DPF's installed in parallel. Using the horse power rating and fuel consumption as a basis for estimation, the Wärtsilä engines would require 48 filter units. The backpressure generated by these devices in series would inhibit proper operation of the Wärtsilä engines. Accordingly, the District has determined that the application of DPF to this project is not viable as the irresolvable technical difficulties would preclude the successful deployment of this technique. Further, this technology has not been proposed nor permitted under the qualifications of an innovative control device consistent with 40 CFR 52.21 (v) or the District SIP. Therefore, the District concludes that DPF is not technically feasible for this project. Because the application of this technology is not technically feasible, the District concludes that a cost effectiveness evaluation is not warranted.

B) Electrostatic Precipitators (ESP)
An ESP is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collection surfaces. In dry ESPs, the collectors are knocked, or "rapped", by various mechanical means to dislodge the particulate, which slides downward into a hopper where it is collected.

Collection efficiency is affected by dust resistivity, gas temperature, chemical composition (of the dust and the gas), and particle size distribution. Typical inlet PM concentrations are 0.5 to 5 gr/scf. Exhaust flows with concentrations below 0.5 gr/scf are also sometimes controlled with ESPs (USEPA). ESPs generally operate most efficiently with dust resistivities between 5 x 103 and 2 x 1010 ohm-cm. According to the EPA, the most difficult particles to collect are those with aerodynamic diameters between 0.1 and 1.0 μm. Particles between 0.2 and 0.4 μm usually show the most penetration. This is most likely a result of the transition region between field and diffusion charging.

ESPs have been applied to Wärtsilä engines operating on diesel and heavy fuel oils. Ultra low sulfur diesel fuel may not be collected as effectively, due to the decrease in available sulfur particles.

C) Baghouses

Baghouse filtration products (BFPs) are filtration fabrics used throughout industry to collect particulate matter. The fabrics are sewn into bags used in fabric filters (baghouses) that are efficient for collecting particles across a wide size range. The fabric filters are not designed to handle exhaust gas temperatures in the range identified for this project.

The following information sources were consulted to identify possible PM10 BACT limits for similar sizes and types of equipment:

1. CARB "Guidance for the Permitting of Electrical Generation Technologies"
2. NEO California Power LLC, Red Bluff, Tehama County Air Pollution Control District 2006 Source Test of natural gas-fired Wärtsilä engines at average operating rate of 2.80 MW
3. Chambersburg, PA Orchard Park Generating Station; Wärtsilä dual-fuel, 5.6 MW engines permitted October 28, 2004.
4. South Coast Air Quality Management District BACT Guidelines Manual
5. Bay Area Air Quality Management District BACT Guidelines
6. CARB RACT/BACT/LAER Clearinghouse
7. Colorado La Junta Municipal Utilities – Natural gas ICE with 10% diesel pilot injection

South Coast Air Quality Management District BACT Guidelines Manual

Kings County – Diesel – 2848 bhp	0.0116 g/bhp-hr – 85% removal efficiency achieved (DPF)
Snow Summit – Diesel - 2,835 bhp with SCR	0.045 g/bhp-hr) permit limit 0.009 g/bhp-hr achieved (including condensables)

CARB "Guidance for Power Plant Siting and Best Available Control Technology"

Natural gas-fired reciprocating engines	0.02 g/bhp-hr
Diesel-fired reciprocating engines	No data available

NEO California Power

Natural gas-fired	Engines 9 & 11: 0.02 g/bhp-hr (permit limit and

reciprocating engines (3,871 bhp-hr)	achieved) No other engines were tested

CARB RACT/BACT/LAER Clearinghouse

Diesel	0.045 g/bhp-hr

Bay Area Air Quality Management District BACT Guidelines

Diesel CI Engine >= 175 hp (TBACT)	0.1 g/bhp-hr achieved in practice

Colorado La Junta Municipal Utilities – Dual Fuel

Natural Gas w/ 10% Diesel Pilot Injection, 4,945 bhp; 8,724 Btu/bhp-hr	0.074 g/bhp-hr
Natural Gas w/ 10% Diesel Pilot Injection, 7,131 bhp; 5,072 Btu/bhp-hr	0.13 g/bhp-hr
Diesel, 4,945 bhp; 6,718 Btu/bhp-hr	7.8 lb/hr
Diesel, 7,131 bhp; 5,731 Btu/bhp-hr	9.6 lb/hr

Orchard Park

Natural gas with diesel pilot injection	No data available
Diesel	1.5 g/bhp-hr

The most comparable engines are the Orchard Park and La Junta dual fuel engines. The Wärtsilä PM emission rates are lower than Orchard Park's and higher than La Junta. La Junta and Wärtsilä emission rates are compared below.

Humboldt NG w/ 0.7% Diesel Injection	0.1g/bhp-hr full load; 0.2 g/bhp-hr low load
CO NG w/ 10% Diesel Injection, 4,945 bhp; 8,724 Btu/bhp-hr	0.07 g/bhp-hr
CO NG w/ 10% Diesel Injection, 7,131 bhp; 5,072 Btu/bhp-hr	0.1 gbhp-hr

PM_{10}	
Humboldt Diesel	10.8 lb/gal
Diesel, 4,945 bhp; 6,718 Btu/bhp-hr	7.8 lb/hr
Diesel, 7,131 bhp; 5,731 Btu/bhp-hr	9.6 lb/hr

D) Oxidation Catalyst

Oxidation Catalyst generally are precious metal compounds that promote oxidation of CO and VOCs to CO_2 and H_2O in the presence of excess O_2. According to a report prepared for the EPA in 2002, CO and NMHC conversion levels of 98% to 99% are achievable. Methane conversion may approach 60 to 70%. The report also states that oxidation catalysts are now widely used with all types of engines, including diesel engines. They are being used increasingly with lean burn gas engines to reduce their relatively high CO and VOC emissions.

The PM limit of 0.14 g/bhp-hr for the natural gas engine identified above is based on the use of an oxidation catalyst and PUC pipeline quality natural gas. The Wärtsilä engines will be equipped oxidation catalysts. When operating on natural gas, the engines will maintain a continuous injection of <1% diesel fuel. Recently, in the Bay Area East Shore project, it was determined that oxidation catalysts are also capable of achieving particulate matter reductions. ARB, EPA and others have published studies demonstrating that oxidation catalysts achieve particulate matter reductions from diesel engines in the range of 20% to 40%. The permit requires the use of oxidation catalysts on the engines to ensure that particulate matter emissions during Diesel fuel firing are minimized.

E) Combustion Controls

Combustion Control refers to controlling emissions of PM_{10} through the design and operation of the engine in a manner so as to limit particle formation. In general, a combustion control system seeks to maintain the proper conditions to ensure complete combustion. The applicant stated that combustion control will be optimized for NOX reduction, but they will additionally have the effect of reducing ROC and PM_{10} emissions.

The Colorado dual fuel engines are permitted at a level that is equivalent to 0.074 g/bhp-hr for the 4,945 hp engine, and 0.13 g/bhp-hr for the 7,131 hp engine. These engines are not required to use ultra low sulfur diesel and do not use DPFs.

Comparison of Emission Rates for Internal Combustion Engines (Natural Gas)

Pollutant	Wärtsilä Emission Factors	Lowest Emission Rates	NSPS & NESHAP Limits
NOX	6 ppmvd @ 15% O2 0.06 g/bhp-hr	6 ppmvd @ 15% O2 0.07 g/bhp-hr	120 ppm (NSPS IIII)
CO	13 ppmvd @ 15% O2 0.08 g/bhp-hr	12 ppmvd @ 15% O2 0.1 g/bhp-hr	Abatement of 70% (NESHAP ZZZZ)
ROC	28 ppmvd @ 15% O2 0.1 g/bhp-hr	25 ppmvd @ 15% O2 0.15 g/bhp-hr	n/a
PM10	0.02 g/bhp-hr	0.02 g/bhp-hr	0.11 g/bhp-hr

Comparison of Emission Rates for Internal Combustion Engines (Diesel)

Pollutant	Wärtsilä Emission Factors	Lowest Emission Rates	NSPS & NESHAP Limits
NOX	35 ppmvd @ 15% O2 0.0.39 g/bhp-hr	50 ppmvd @ 15% O2 1.5 g/bhp-hr (different sources)	120 ppm (NSPS IIII)
CO	20 ppmvd @ 15% O2 0.14 g/bhp-hr	89 ppmvd @ 15% O2 0.035 g/bhp-hr (different sources)	Abatement of 70% (NESHAP ZZZZ)
ROC	40 ppmvd @ 15% O2 0.16 g/bhp-hr	39 ppmvd @ 15% O2 0.0026 g/bhp-hr	n/a
PM10	0.21 g/bhp-hr total PM10; Filterable PM10 is 0.11g/bhp-hr	0.0116 g/bhp-hr	0.11 g/bhp-hr (NSPS IIII, filterable PM10)

Eliminate Technically Infeasible Options
ESP
Baghouse
DPF

Remaining Technologies
Combustion Controls
Oxidation Catalyst

<u>BACT DETERMINATION</u>

As discussed earlier, engines of this size have not previously been permitted in California; neither have natural gas engines with diesel pilot ignition. The largest California permitted diesel engines have ratings just over 2,000 horsepower and have demonstrated the ability to meet BACT standards. The applicant proposes to meet a PM_{10} emission limit of 3.6 lb/hr (0.14 g/bhp-hr) during natural gas operation. During diesel operation, the applicant will meet a limit of 10.8 lb/hr (0.21 g/bhp-hr) for total particulate, and a limit of 0.11 g/bhp-hr for filterable PM_{10}. These levels are achievable based upon the application of combustion controls proposed and use of the Oxidation Catalyst.

The District has determined that the use of a selective catalytic reduction and lean burn technology represents BACT for NOx for this project. The District has also determined that the use of an oxidation catalyst in combination with after cooling and combustion controls represents BACT for CO, PM_{10}, and ROC for this project.

Ambient Air Quality Standards (NCUAQMD Rule 110 Section 7)

The purpose of NCUAQMD Rule 110 is to establish pre-construction review requirements which are designed to ensure that the operation of a new or modified source will not interfere with the attainment or maintenance of State and Federal Ambient Air Quality Standards. Section 7 of the Rule provides the APCO discretion to determine when air quality modeling is necessary, and to decide what model and protocol must be used. If deviation from EPA's "Guidelines on Air Quality Models, OAQPS 1.2-080" is deemed necessary, a model may only be designated after allowing for public comment and only with concurrence of CARB and EPA.

It is always desirable to utilize the model and protocol which will most accurately simulate the dispersion of pollutants. The more sophisticated the model, the more data inputs are required in order to prepare the simulation. The applicant proposed to use a computer software program known as CTDMPLUS to estimate pollutant dispersion. In part, because the meteorological data necessary to run the model was not available, the EPA was unable to approve the use of this model. In its place, AERMOD and CTSCREEN were utilized for flat terrain and for complex and intermediate terrain respectively.

The model simulations reflect emission activity based on the proposed Wärtsilä engine duty cycle. The proposed operating schedule is listed in Table 1 (Operating Schedule), and the list of possible operating scenarios is found in AFC Table 8.1B-3. The worst case met conditions were then paired with worst case operating conditions in order to ensure impacts were over predicted. With these conservative assumptions, no violations of the ambient air quality standards are predicted for NO_2, SO_2, or CO as is shown in Table 16 below. PM_{10} and $PM_{2.5}$ will be discussed in subsequent sections.

Table 16 - Ambient Air Quality Impact Analysis (micrograms/cubic meter)

Pollutant	Averaging Time	Maximum Facility Impact (ug/m^3)	Total Impact (ug/m^3) (including background data)	State Standard (ug/m^3)	Federal Standard (ug/m^3)
NO2	1-hour	261.8[1]	337	338	-
	Annual	2.5	20	56	100
SO2	1-hour	25.4	140	650	-
	3-hour	18.3	88	-	1,300
	24-hour	3.7	25	109	365
	Annual	0.1	5.9	-	80
CO	1-hour	492.2	3,742	23,000	40,000
	8-hour	242.2	2,220	10,000	10,000

Note: 1) Operation in compliance with the 392 lb/hr limit

The NCUAQMD is classified as being in attainment with the federal and state AAQS for $PM_{2.5}$ and the federal standard for PM_{10}. However, the NCUAQMD exceeds the state 24–hour AAQS for PM_{10}. The most recent $PM_{2.5}$ annual concentration data available is for calendar year 2004 where the annual average was calculated according to the national method.

Table 17.0 Background Concentrations Prior to the Proposed Project

Pollutant	Averaging Time	Background Concentration[1]	State Standard	Federal Standard
PM10	24-hour	72.2 (2006)	50	150
	Annual	21.1 (2004)	20	50
PM2.5	24-hour	32 (2005)	-	35
	Annual	8.2 (2004)[2]	12	15

Note: 1) (AFC Table 8.1-25); 2) National

To predict 24-hour PM impacts, ambient modeling runs were performed using the parameters for Scenario 1G, full engine load at 87˚F ambient temperature, identified in

AFC Table 8.1B-3. Table 8.1B-5 indicates that scenario 1G was utilized to estimate compliance with the annual standards for PM_{10} and $PM_{2.5}$. The proposed project's emissions were evaluated in combination with background ambient air concentrations to determine the project's impacts. EPA Guidance (71 FR 6727) provides that compliance with federal PM2.5 NAAQS should be evaluated using the PM10 NAAQS and not modeled directly. As shown in the following tables, PM impacts exceed the state 24-hr and annual PM_{10} standards. NCUAQMD Rule 110 §5.5 requires that the APCO take into account emissions mitigation provided by offsets obtained pursuant to the regulation. Since state PM_{10} standards will be worsened, offsets will be provided for all PM_{10} emissions above 25 tons per year. Compliance with the California AAQS for the annual $PM_{2.5}$ standard (AFC Table 8.1 B-4) was demonstrated using screening methodology and PM_{10} as a surrogate.

Table 17.1 – PM impacts without background

Pollutant	Averaging Time	100 hours/yr Impact	Maximum Operating Impact	State Standard	Federal Standard
PM10	24-hour	32.9	105.1	50	150
	Annual	2.3	23.4	20	50
PM2.5	24-hour	-	-	-	35
	Annual	2.3	10.5	12	15

Compliance by Other Owned, Operated, or Controlled Sources NCUAQMD Rule 110 Section

The applicant is required to certify that other sources in California that are owned by the same applicant and that have a potential to emit greater than 25 tons per year, are in compliance, or on a schedule for compliance, with all applicable emission limitations and standards.

This certification was submitted to the NUCAQMD along with the District application.

<u>Prevention of Significant Deterioration (PSD)</u> NCUAQMD Rule 110 §11

The District has a SIP-approved PSD program, which is based on the requirements of 40 CFR 51.166. The applicant is required to conduct an air quality analysis to demonstrate that the potential new emissions from the proposed source, in conjunction with other applicable emissions from existing sources (including secondary emission from growth associated with the new project), will not cause or contribute to a violation of any PSD increment. An impact analysis is required for each pollutant with a potential to emit that exceeds the significance threshold. An impact analysis must include the following components: air, ground and water pollution on soils, vegetation, and visibility [40 CFR 51.166(o)].

Secondary Growth

As part of the AFC, the applicant has evaluated the potential for secondary growth, soil and vegetation impacts, and visibility impacts (AFC Sections 8.1 Air Quality, 8.10 Socioeconomics, and Section 8.11 Soils and Agriculture). The project is the equivalent (electrical generation capacity) replacement of existing power generating equipment, and therefore, is not anticipated to result in any appreciable impacts in these subject areas. A summary follows.

The existing facility has a maximum generating capacity of roughly 135 MW. Historically, only 700,000 MWh or approximately 60% of the annual capacity factor has been utilized. The proposed project will result in a 7.6% maximum generating capacity increase as established by the following calculations.

The existing facility consists of:

- Two Mobile Emergency Power Plants with a 15 MW capacity each which are limited to 3120 hrs per year of operation each; and
- One 52 MW boiler and one 53 MW boiler without restrictions

$$(30\ MW * 3120\ hrs/yr) + \ (105\ MW * 8760\ hrs/yr) = 1{,}013{,}400\ MW\ hrs/yr$$

The new facility will consist of ten 16.6 MW engines which will be limited to 75% of their annual capacity factor.

$$(10\ engines * 16.6\ MW\ per\ engine * 8760\ hrs/yr * 0.7) = 1{,}090{,}620\ MW\ hrs\ /\ yr$$

$$\frac{\big((1{,}090{,}620\ MW\ hrs.per\ yr) - (1{,}013{,}400\ MW\ hrs\ per\ yr)\big)}{1{,}013{,}400\ MW\ hrs\ per\ yr} = \ 0.076$$

Population – Residential, Industrial, & Commercial Impacts

The population growth, as predicted by the California Department of Finance in 2006, for Humboldt County from 2010 through 2030 is projected to be less than 9,276 persons which equates to a 6.96% increase. The existing facility’s electrical generating capacity is adequate to service this expansion, and the new facility’s capacity is nearly equivalent. The construction phase of the project will result in the addition of approximately 100 new jobs of which roughly 1/3 will be from local contractors: The remaining two thirds will require lodging. The vacancy rate in Eureka is approximately 5.8% of 12,150 total units, and therefore, new housing construction is not anticipated. Operation of the new facility will require 27 less staff persons, and as such, long term spending and housing may actually be reduced as a result of the project. Thus, the replacement project will not cause a significant population change or housing impacts to the region.

The construction and operation of the facility will not directly or indirectly result in the operation or construction of another ancillary or supporting facility (e.g. a new mine collocated with an ore processing facility). Humboldt County’s current general plan document and County zoning ordinances afford the opportunity for further development of the Humboldt Bay Harbor industrial areas. The existing facility’s electrical generating capacity is adequate to service the proposed development. Thus, the replacement project will not cause or contribute to a significant expansion of industrial or commercial activity in the region.

After completion of an independent analysis, the District has determined that the secondary growth associated with the project will be de-minimis, thus additional secondary emission increases as a result of the project are not anticipated. Accordingly, only the emissions reductions which will occur from the shutdown of the existing facility, and the emissions from the operation of the new facility were considered in the PSD analysis.

Air Quality

A PSD applicability analysis is required for each pollutant with a potential to emit that exceeds the significance threshold. The net change in emissions was calculated based upon emissions from the existing facility (AFC Table 8.1-32) and emissions from the proposed facility (Table 9 – Annual Emission Rates). The significance threshold are defined in Regulation I, Rule 101.1.266 and identified in Table 18 below.

Table 18 – PSD Applicability

Pollutant	Proposed Net Emissions Changes Tons/Year (Reduction)	Significant Emissions Rate Threshold Tons/Year
NO_2 (NOX)	(757.5)	40
O_3 (VOC)	**166.4**	40
SO_2	(25.7)	40
PM_{10}	**92.4**	15
CO	**60.4**	100

VOC and PM_{10} emissions increases exceed the Significant Emissions Rate. Increment consumption analysis is not required for VOC emissions; however, it is required for PM_{10} emissions. The applicant submitted Class I and Class II increment consumption analyses. Class I increment consumption was estimated to be 5% of the allowable increment. For the Class II increment consumption analysis, the District modeled the ambient impact of major PM_{10} sources within 50 km of the impact area (Appendix E). The results of the modeling analysis are identified in Table 19 below.

Table 19 Modeled Impacts and PSD Class II Increments

Year	24-Hour Highest 2nd High Concentration (ug/m^3)	Annual Average Concentration (ug/m^3)
2001	18.3	-0.12
2002	21.7	-0.68
2003	**24.2**	0.06
2004	21.9	**0.23**
2005	18.2	-0.10

The PM_{10} Class II increment 24-hour and annual limits are 30 ug/m3 and 17 ug/m3 respectively. Thus, the PM_{10} increment consumption by the proposed project in combination with the existing contributing sources will be lower than the allowable increment for both the 24-hour and annual averaging periods.

Visibility

The Federal Land Managers (US Department of the Interior and the Department of

Agriculture) performed an independent review of the proposed project and provided the following comments.

- The VISCREEN plume analysis results suggest that there will not be any perceptible visibility impacts associated with the emissions from the plant at Redwood National Park, nor the Marble or Yolla Bolla wilderness areas.

- The applicant originally proposed a limit of 0.21 g/bhp-hr when operating in Diesel Mode, which given the NCUAQMD's attainment status, was not sufficient to qualify as BACT. The applicant has since revised the limit to 0.15 g/bhp-hr.

- Future modeling conducted to predict regional haze should be performed with CALPUFF rather than CALPUFF-Lite.

- Encourage the applicant to consider voluntary green house gas emission offsets.

Vegetation and Soils
The Humboldt Bay Power Plant is located on a small peninsula, known as Buhne Point, along Humboldt Bay. The 143 acre site is within an unincorporated area of Humboldt County approximately 3 miles south of Eureka city limits. Power generating equipment has been located at the site in excess of 50 years.

Soil types and land use types are identified in AFC Section 8.11.1.2 Soils and Figure 8.11-2. Areas designated as prime agricultural farmland exist within one mile of the proposed project, though much of this agricultural land has been converted to residential uses. The remaining sections are in costal redwood timber production and grassland / rangeland crop rotation. Seasonal wetlands and waters of the United States under the protection of the Clean Water Act (CWA) are also located within one mile of the project site.

The maximum concentrations of NO_2, CO, SO_2, and PM_{10} are predicted to be less than all of the applicable national primary and secondary ambient air quality standards. Criteria used to establish these standards include crop protection. The projected maximum one hour average concentration of NO_2 as a result of operation of the project at steady state conditions combined with background concentrations of NO_2 is 284 ug/m3. This level is below the current state standard of 470 ug/m3 as well as the proposed standard of 338 ug/m3.

PSD Compliance
After completion of an independent analysis, the District has determined that the ambient air quality impacts analysis prepared by the applicant adequately identifies potential impacts from operation of the new facility. Secondary growth associated with the project will be de-minimis, thus additional impacts as a result of the project are not anticipated. Both the Class I and Class II increment consumption analysis demonstrate compliance.

PROHIBITORY RULES COMPLIANCE

NCUAQMD Rule 104.2 – Visible Emissions

Visible emissions from the engines are expected to comply with the 40% opacity requirement of this rule during normal operations and during startup and shutdowns.

NCUAQMD Rule 104.3.4.1 Particulate Matter Emissions from General Combustion Sources

The proposed project is expected to comply with the particulate matter emission limit of 0.20grains/ standard cubic foot. Based on the data reported in the AFC, Table 8.1A-3, the maximum PM_{10} emission rate would be 0.04 grains/dscf.

NCUAQMD Rule 104.5 – Sulfur Oxide Emissions

SO_2 emissions from the proposed project are expected to comply with the 1,000 ppm SO_2 limitation.

NSPS COMPLIANCE (NCUAQMD Rule 104 §11)

Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60 Subpart IIII)

Subpart IIII applies specifically to manufacturers, owners and operators of stationary compression ignition (CI) internal combustion engines. The Subpart defines CI engines as any engines that are not spark ignition engines.

The Subpart's definition for spark ignition engines includes the following:
"*Dual-fuel engines in which a liquid fuel…is used for CI and gaseous fuel…is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition* engines".

Based on the tables below, the maximum potential annual average ratio of diesel to natural gas, calculated as described above, is 1.6%. There is the possibility that the engines could be operated for additional periods in Diesel Mode (natural disaster i.e. earthquake). As such, for the purposes of this Subpart, the Wärtsilä engines should be considered Compression Ignition (CI) Engines and accordingly, the Subpart applies to them.

Natural Gas		
	MMBtu	**scf**
Hourly	144	1,409,403
Daily	3,454	33,825,661
Annual	927,723	9,086,418,217

Diesel Pilot		
	MMBtu	**Gallons**
Hourly	0.8	58
Daily	19	1,402
Annual	5,158	376,734

Diesel Mode		
	MMBtu	**Gallons**
Hourly	148.9	1,088
Daily	3,574	22,190
Annual	14,890	108,760

The Wärtsilä engines are classified, for the purposes of compliance with the NSPS as "non-emergency stationary CI Internal Combustion Engines with a displacement of greater than or equal to 30 liters per cylinder" and therefore must meet the following requirements.

a. Reduce NOX emissions by 90% or more, OR limit NOX emissions to 1.6 g/KW-hr (1.2 g/bhp-hr).
b. Reduce PM emissions by 60% or more, OR limit PM emissions to 0.15 g/KW-hr (0.11 g/bhp-hr).

The Wärtsilä engines are guaranteed by the manufacturer to emit a maximum of 0.56 g/KW-hr (0.39 g/bhp-hr), less than the maximum allowed by the NSPS. The manufacturer also guarantees a diesel PM maximum emission rate of 0.15 g/KW-hr. The permit will be conditioned so as to limit the emissions of PM to 0.11 g/bhp-hr.

The black-start generator and fire pump engine are not required to meet the NSPS standards, because they are emergency engines.

NESHAP COMPLIANCE:

National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (40 CFR 63 Subpart ZZZZ)

The facility is a major source for hazardous air pollutants (HAPs), having the potential to emit 10 tons or more per year of one HAP, and 25 tons or more per year of more than one HAP. There are multiple types of Reciprocating Internal Combustion Engines (RICE) regulated by this NESHAP. The Wärtsilä reciprocating dual- fuel engines qualify, by definition, as CI engines when operating in Diesel Mode:

"Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel."; and

> "*Compression ignition engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition, including diesel engines, dual-fuel engines, and engines that are not spark ignition.".*

40 CFR 63 Subpart ZZZZ requirements include:

- Emission and Operating Limitations §63.6600(b)
- General Compliance §63.6605
- Initial Performance Testing §63.6610(a)
- Subsequent Performance Testing §63.6615
- Monitor Installation, Operation and Maintenance §63.6625
- Notifications, Reports, and Records $63.6645

The applicant has chosen to comply with the NESHAP by reducing CO emissions by 70% or more; and consequently has proposed emission limits that reduce CO emissions by 96.8% when operating on natural gas, and 88.9% when firing diesel fuel. The permit will be conditioned to require:

- During initial performance test simultaneous measurement of both CO and O2 at the inlet and outlet of the control device using ASTM D6522-00.
- Demonstration of initial compliance with the emission limitations using CEMs to continuously monitor CO and O2 at both the inlet and outlet of the control device (§63.6625(a)) after a performance evaluation has been successfully completed using PS3 and 4A of 40 CFR Part 60 Appendix B which showed compliance with the monitoring requirements of the Subpart; and with the average reduction of CO calculated using §63.6620 equaling or exceeding 70% reduction.
- The initial test shall be performed the first 4 hour period after successful validation of the CEMS. All data from the CEMS shall be collected in accordance with §63.6625(a) reducing the measurements to 1-hour averages, calculating the percent reduction of CO according to §63.6620; demonstrating that the catalyst achieves at minimum a 70% reduction of CO over a 4-hour period; and conducting an annual RATA using PS3 and 4A of CRF Part 60 Appendix B as well as daily and periodic data quality checks in accordance with 40 CFR Part 60 Appendix F, procedure 1.
- Continual compliance with the emission and operating limitations except during periods of startup, shutdown, and malfunction
- Operation and maintenance of the engines and control devices consistent with good engineering practices for minimizing emissions at all times
- Notification to EPA in accordance with §63.7(b) and (c), §63.8 (e)
- Recordkeeping in accordance with 63.6595(b)(5) which will can be satisfied through submittal of reporting required by Title V permit.

Due to recent amendment of the Subpart, the emergency generator is now subject to emission limitations. For engines in this size range, manufacturers are required to provide certification of compliance with emission standards. The permit will be conditioned to prohibit installation on non-certified devices.

California Airborne Toxic Control Measure
Stationary Compression Ignition Engines (17 CCR Section 93115)

The ATCM defines a compression ignition engine by the following: "Compression Ignition (CI) Engine means an internal combustion engine with operating characteristics significantly similar to the theoretical diesel combustion cycle. The regulation of power by controlling fuel supply in lieu of a throttle is indicative of a compression ignition engine." The Wärtsilä engines, when operating in natural gas firing mode, do not meet this definition, as their operation is different than the theoretical diesel combustion cycle. The natural gas operating mode is more similar to the Otto cycle of a spark ignition engine. However, the Wärtsilä engines, when operating in the diesel firing mode meet the definition of CI Engine; therefore, the engines must comply with the ATCM when running on diesel fuel.

The ATCM sets forth diesel particulate matter (DPM) emission limits for new engines, which are categorized, by definition, as either Emergency Standby Engines or Prime CI Engines. Prime CI Engines are defined as any engine that is not an Emergency Standby Engine. The definition for Emergency Standby Engine includes a stationary engine that: (A) is installed for the primary purpose of providing electrical power or mechanical work during an emergency use and is not the source of primary power at the facility; and (B) is operated to provide electrical power or mechanical work during an emergency use; and (C) is operated under limited circumstances for maintenance and testing, emissions testing, or initial start-up testing.

For purposes of this project, the definition of Emergency Use includes providing electrical power or mechanical work in the event of the failure or loss of all or part of the normal natural gas supply to the facility: (A) which is caused by any reason other than the enforcement of a contractual obligation the owner or operator has with a third party or any other party; and (B) which is demonstrated by the owner or operator to the District APCO's satisfaction, to have been beyond the reasonable control of the owner or operator.

The applicant, PG&E, is the primary electricity provider for the County of Humboldt. PG&E obtains its natural gas fuel supply from PG&E's gas operations. PG&E, as a gas supplier, operates under Gas Rules, or Tariffs, that define the company's relationship with its customers. Rule 14 provides that,

> *"when operational conditions exist such that supply is insufficient to meet demand and deliveries to Core End-Use Customers are threatened…PG&E may divert gas supply in its system from Noncore End-Use Customers to Core End-Use Customers. If a Noncore End-Use Customer's supply is diverted…that Customer must stop or reduce its use of natural gas."*

The applicant is defined as a Noncore End-Use Customer in Rule 1:

> *"Noncore End-Use Customers are typically large commercial, industrial, cogeneration, wholesale or electric generation Customers who meet the usage requirements for service under a noncore rate schedule and who have executed a Natural Gas Service Agreement. Electric Generation, Enhanced Oil Recovery, Cogeneration, and Refinery Customers with historical or potential annual use exceeding 250,000 therms per year or rated generation capacity of five hundred kilowatts (500 kW) or larger, are permanently classified as Noncore End-Use Customers."*

As a Noncore End-Use Customer, the applicant is required to curtail its natural gas use during shortfalls. In Humboldt County, such shortfalls typically occur during the winter months, when overall customer gas use increases. Under the ATCM's Emergency Use definition, CARB determined, in correspondence dated March 10th 2006, that an engine would be an Emergency Standby Engine if the emergency use were the result of the enforcement of a contractual obligation the owner or operator has with another party.

All engines will operate only on CARB Diesel or Alternative Fuel, as defined in the ATCM. The engines will operate for a maximum of 50 hours per year per engine for testing and maintenance purposes. There is no limit in the ATCM on the amount of hours allowed for emergency operations; however, engine hours will be limited to no more than 100 for the combined purpose of maintenance and testing and during periods of natural gas curtailment. All engines will meet the ATCM emission standard of 0.15 g/hp-hr while operating in Diesel Mode. The black-start generator and fire pump are also emergency back-up generators and subject to the requirements of the ATCM for New Emergency Backup Engines. Because the reciprocating engines are dual fueled, they were specifically left out of the permit definition for Diesel Particulate Matter ATCM Emergency Use.

It should be noted that the Stationary Diesel Engine ATCM was designed to address diesel emergency backup engines and prime engines where the access to grid power was not readily available or reliable. In developing the ATCM, duel-fueled, multi-engine power generating stations were not envisioned. As a result, CARB believes that the ATCM should be viewed as a minimum level control of compliance in this situation and the required level of control should be based on a source specific analysis of best available control technology.

DISCUSSION

Health Risk Assessment
Current NCUAQMD Regulations do not require the applicant to submit Health Risk Assessment (HRA) information to the APCO for consideration during the Authority to Construct review process, nor do they provide guidance on acceptable levels of risk for carcinogenic effects, or acute and chronic exposure. However, for purposes of California Environmental Quality Act (CEQA) compliance, the California Energy Commission required the applicant to perform an HRA to estimate impacts to public health. The impact on public health due to the emissions of toxic compounds was assessed utilizing approved air dispersion models and using worst-case emissions of toxic air contaminants from the project.

PSD Permit
The federal Prevention of Significant Deterioration (PSD) program was delegated to the District on August 30th 1985. It is the District's intent for the FDOC to serve as the District local permit, as well as the PSD permit for the facility. Accordingly, the FDOC contains all of the preconstruction permit requirements and delineates federally enforceable conditions in the document by listing them in a separate section [Rule 504 §2.3].

Source Testing
Reciprocating internal combustion engines of this size with dual fuel capability utilizing diesel pilot configuration have not previously been permitted in California. Because the application of this technology in the proposed configuration is relatively new, data availability on long term performance characteristics is limited. These factors were given considerable weight when developing the source testing requirements for the engines. After a reasonable data set has been acquired (e.g. 3 years of operational and source testing data), the District may elect to revisit the testing requirements and may waive some of the requirements if compliance has been demonstrated by a sufficient margin (e.g. emissions are <50% of permitted limit).

The District has determined that source testing of the engines at three specific loads (50%, 75%, and greater than 95%) will represent conditions which will most challenge the pollution control equipment, and accordingly, the permit will be so conditioned. For the initial performance test, each engine will be tested at each of the three loads during operation in both fuel modes (Diesel and Natural Gas Modes). Thereafter, source testing requirements differ based upon fuel type. Each engine will be assigned to one of three engine groups (e.g. A, B, and C) with 3, 3, and 4 engines, respectively, in each group.

Wärtsilä Engine Groups

Group	Engines
A	S-1 through S-3
B	S-4 through S-6
C	S-7 through S-10

While in Natural Gas Mode, every engine will be tested each year at one of the three loads. For example, during year one, all engines in group A will be tested at 50%. The load value will then rotate annually such that all engines are tested at least once at each load in a three year period; and that on each year, they are tested at a different load.

Annual Testing in Natural Gas Mode

Group	Year		
	1	2	3
A	50%	75%	>95%
B	75%	>95%	50%
C	>95%	50%	75%

In Diesel Mode, each engine will be tested once every three years or following each 200 hours of operation of an individual engine. The engines will be tested on a rotating basis with a minimum of one third of the engines to be tested each year at each of the three loads.

Annual Testing in Diesel Mode

Group	Year		
	1	2	3
A	Yes	Hrs > 200	Hrs > 200
B	Hrs > 200	Yes	Hrs > 200
C	Hrs > 200	Hrs > 200	Yes

Note: "Yes" indicates mandatory testing that year. "Hrs>200" indicates testing required if hours of operation since last source test exceed 200 AND testing required for each 200 thereafter.

Using Year 1 as an example, all engines in Group A will be tested regardless of the number of hours of operation. Should an engine in Groups B or C exceed 200 hrs of operation, that individual engine would be tested only – not the entire group. As a second example, Engine S-4 (member of Group B) is tested three times in Year 1 because it operated greater than 600 hrs. Group B is scheduled for mandatory testing in Year 2. Engine S-4 must be tested in year 2 regardless of the number of hours of operation. In this example, Engine S-4 could be operated for at least 200 hrs that year, thereby limiting the number of source tests and number of engines tested.

Conclusion

The installation and operation of the permitted units described in this evaluation should comply with all local, state, and federal emission requirements when operated in accordance with the Authority to Construct Temporary Permit Operate #440-1. Further, staff has evaluated the information presented by the applicant and applicable rules and regulations, and believes sufficient evidence exists for the APCO to make the determinations required under Rule 102 §1.2 and Rule 103 §7.0 and issue a Final Determination of Compliance.

EVALUATED BY: ______________________ **DATE:** 4/11/08

Jason L. Davis, Division Manager

APPENDICIES

A - Authority To Construct 443-1

B - Stationary Diesel ATCM Applicability Determination – CARB

C - Comments on Air Quality Analysis – National Park Service

D - Comments on Air Quality Analysis – US Forest Service

E – Class II Increment Modeling Analysis – Atmospheric Dynamics

Class II PM_{10} Increment Modeling Analysis
Humboldt Bay Repowering Project

Introduction

Atmospheric Dynamics, Inc. (ADI) was contracted by the North Coast Unified Air Quality Management District (District) to prepare an independent Class II PM_{10} increment analysis for the proposed Humboldt Bay Repowering Project (HBRP). Pacific Gas & Electric Company (PG&E) has submitted an Application for Certification[1] (AFC) for the repowering project at its Humboldt Bay Power Plant (HBPP) located southwest of Eureka, California, just west of Highway 101, off King Salmon Drive. This report describes the PM_{10} increment inventory that was developed for the project and the results of the air quality dispersion modeling used for the increment modeling.

Project Description

The HBRP will involve the installation and operation of ten (10) 16.3 megawatts (MW) dual fuel (natural gas and distillate fuel oil) reciprocating engine-generator sets, one (1) 469 horsepower (hp) diesel-fired emergency IC engine-generator, and one (1) 210 hp diesel-fired emergency IC engine powering a fire water pump. The HBRP will replace the existing fossil fuel power generating units currently operating at the HBPP. The nominal power plant output after repowering will be 163 MW.

The existing HBPP includes four operating units. Two (2) natural gas and/or fuel oil fired steam boilers (Units 1 and 2) with capacities of 52 and 53 megawatts, respectively, which began operation in 1956 and 1958; and two (2) distillate fuel oil fired 15 megawatt peaking turbines (Mobile Electric Power Plants [MEPPs 2 and 3]). A non-operating 63 MW nuclear power plant also exists at the facility. The existing operating power generating units will be shut down once the new reciprocating engines are installed and operational.

The generating units at the HBRP will consist of ten Wärtsilä 18V50DF 16.3 MW lean-burn reciprocating engines, each equipped with selective catalytic reduction (SCR), an oxidation catalyst, and associated support equipment including continuous emission monitors. The primary fuel will be natural gas with diesel pilot injection, and the backup

[1] Application for Certification, Humboldt Bay Repowering Project. Submitted by Pacific Gas and Electric Company, September 2006.

fuel will be CARB diesel fuel, which will be used during emergencies or during natural gas curtailment in the region.

Regulatory Requirements for Increment Analysis

The USEPA has promulgated Prevention of Significant Deterioration (PSD) regulations for areas that are in compliance with the national ambient air quality standards (NAAQS). The PSD regulations were enacted primarily to "prevent deterioration" of air quality in areas of the country where the air quality was better than the NAAQS. The PSD program allows new major sources of air pollution to be constructed, or existing major sources to undergo major modifications, while protecting existing ambient air quality, protecting Air Quality Related Values (AQRVs) in Class I areas (i.e., specified national parks and wilderness areas, and other natural areas of special concern), and to assure that appropriate emission controls are applied, in addition to ensuring that any decision to increase air pollution is made only after full public consideration of all the consequences of such a decision. The region where the HBRP is located is classified as "attainment" or "unclassified" for all pollutants with respect to the NAAQS. As discussed in the AFC (Section 8.1.5.2.1.1), the HBRP will be a major modification to a major stationary source that will result in significant net emissions increases of PM_{10} and reactive organic gases (ROG), and therefore subject to the PSD permitting requirements.

The USEPA has delegated the authority to implement the PSD program to various California air pollution control districts, including the NCUAQMD. The proposed project is subject to District Regulation I, Rule 110, which contains the District's New Source Review (NSR) and PSD permitting requirements, as well as Rule 1-200(c) and 1-220, adopted March 14, 1984, and approved by the USEPA as part of the State Implementation Plan (SIP). The District has been delegated the authority to perform PSD review in accordance with the requirements of the 1984 rules.

The PSD regulations, applied on a pollutant-specific basis, require a demonstration that a proposed facility will not cause or contribute to, air pollution in excess of any maximum allowable increase or maximum allowable concentration for any pollutant. The "maximum allowable increase" of an air pollutant that is allowed to occur above the applicable baseline concentration for that pollutant is known as the PSD increment. The maximum allowable concentration is the ceiling established by adding the PSD increment to the baseline concentration. Currently, increments have been established for three pollutants – sulfur dioxide, nitrogen dioxide, and PM_{10}. For PM_{10}, the allowable increments have been established for 24-hour and annual averaging periods, and are shown in the table below for Class II areas. Increments for $PM_{2.5}$ have not yet been established.

Table 1 - Class II PM_{10} Increments

Averaging Time	Allowable Increment ($\mu g/m^3$)
24-hour	30
Annual	17

The baseline concentrations are defined for each pollutant and averaging time, and are generally the ambient concentrations of each pollutant existing at the time when the first complete PSD permit application for the area is submitted. Three dates are important in establishing the baseline concentration and calculating the amount of increment consumed by the major source undergoing PSD review and other applicable emissions increases or decreases at other sources. These dates are:

Major source baseline date: The date after which actual emissions (increases or decreases) associated with construction, as defined at 40 CFR 52.21(b)(8), at a major stationary source affects the available increment.

Trigger date: The date after which the minor source baseline date may be established.

Minor source baseline date: The earliest date after the trigger date that a complete PSD application is received by the reviewing agency. After this date, actual emissions changes (including existing sources that have been modified or have changed their capacity utilization or hours of operation) from all sources (major and minor stationary sources, area sources, and mobile sources) affect increment.

Under this approach, the baseline concentration is not actually established for a PSD baseline area until after the minor source baseline date is established by the submission of the first complete PSD permit application for a source whose emissions would affect a given baseline area. Although major source emissions may affect increment prior to this date, they are not factored into the calculation until the minor source baseline date is triggered. Once the minor source baseline date associated with the first proposed new stationary source or major modification in an area is established, the new emissions from that source consume a portion of the increment in that area, as do any subsequent emissions increases that occur from any source in the area.

NCUAQMD regulations require that before an Authority to Construct for a facility projecting significant increases in NO_2, SO_2, or PM_{10}, an increment analysis must be conducted to demonstrate that the project will not cause exceedances of applicable increments. The HBRP is expected to result in a net reduction in NOx emissions, a minor decrease in SO_2 emissions, and an increase in PM_{10} emissions above the significant emissions level of 15 tons per year. Therefore, an increment evaluation for PM_{10} is required but not for NO_2 or SO_2.

In the NCUAQMD the PM_{10} baseline and trigger dates are as follows:

Table 2 - PM_{10} Increment Baseline and Trigger Dates in the NCUAQMD

Major Source Baseline Date	January 6, 1975
Minor Source Trigger Date	August 7, 1977
Minor Source Baseline Date	October 20, 2006

The NCUAQMD determined that no complete PSD permit application had been received for a major source or significant modification for PM_{10} prior to the HBRP application, so the minor source baseline date is the date the HBRP application was determined complete.

Thus, the sources that affect available increment, and therefore must be included in an increment analysis are:

1) Major sources (as defined at 40 CFR 52.21(b)(1)) or major modifications (as defined at 40 CFR 52.21(b)(2)) that have increased or decreased actual emissions after the major source baseline date (January 6, 1975) as a result of construction of a new source, a physical or operational change to an existing source, or a shutdown of an existing source; and
2) Any source that has had an increase or decrease in actual emissions since the minor source baseline date.

Since the HBRP triggers the minor source baseline date, the only PM_{10} emissions that are included under condition (2), above, are the net change in PM_{10} emissions from the HBRP. However, other sources meeting the criteria of condition (1) above were included in the PM_{10} increment analysis.

Once the baseline dates are identified an emissions inventory must be prepared for each averaging period for which an allowable increment has been specified (in this case, 24-hour and annual averages for PM_{10}). In many cases, direct emissions data are not available for some or all averaging periods, and actual emission must be estimated for these sources. This can be challenging for existing sources where the baseline emissions must be determined and the baseline date is well in the past (e.g., January 6, 1975). The approach generally used per USEPA guidance has been to base the annual emissions inventory on the actual emissions measured or actual hours of operation, fuel usage, raw materials used, etc., while basing the emissions inventory for shorter averaging periods on the maximum emissions for each averaging period as determined from available data (again, emission measurements, operating hours, fuel or materials consumption, etc.).

Increment Analysis Methodology

Overview

The general approach used for increment analyses involves the following steps:

1. Determining the significant impact areas for each pollutant and averaging period.
2. Identify other sources in the vicinity of the new or modified source whose emissions affect the impact area.
3. Estimate emissions from those sources that affect increment (consume or expand increment).
4. Model the change in emissions to get a concentration change, and compare that concentration change to the applicable increment.

Each of these steps is discussed in more detail below.

Significant Impact Area Determination

The first step in the PM_{10} increment analysis is to determine the significant impact area for both the 24-hour and annual average periods. The impact area includes the area where the emissions from HBRP may cause a significant ambient impact. The applicable significant impact levels for PM_{10} are:

Table 3 - PSD Significant Impact Levels for PM_{10}

Averaging Period	Significant Impact Level ($\mu g/m^3$)
24-hour	5
Annual	1

The significant impact area is a circular area with the radius extending from the source to (1) the most distant point where modeling indicates a significant impact will occur, or (2) a distance of 50 km, whichever is less. The highest modeled concentrations are used in determining the impact area.

As discussed below in the Increment Modeling section, the AERMOD model with five years of meteorological data from Woodley Island was used to determine PM_{10} concentrations in the project region and establish the impact areas. Maximum short term (24-hour) and annual average emission rates (detailed in the Emissions Inventory section, below) for HBRP emission sources were used in the modeling. Based on the modeling analysis, the 24-hour emissions resulted in the largest impact area, an area surrounding the proposed project with a radius of 18.6 km. This is the region where the proposed HBRP could potentially have a "significant" affect on ambient PM_{10} levels. The significant impact area is shown in Figure 1.

Since the proposed repowering project includes the shutdown of the existing operating HBPP generating units, the significant impact area associated with the overall net change in project PM_{10} impacts was also determined. This significance area has a radius of 3.8 km and is also shown in Figure 1.

Identification of Increment Affecting Sources

Once the impact area was determined, PM_{10} sources potentially affecting increment within the impact area were identified and emission inventories developed for these sources. Additionally, sources located outside the impact area with PM_{10} emissions that could contribute to ambient impacts within the impact area were identified and evaluated. In order to ensure that other emissions sources that might have significant impacts within the impact area in conjunction with the proposed project were identified, major PM_{10} sources within 50 km of the impact area (about 69 km from the project) were evaluated.

As discussed above, for the HBRP increment analysis the sources to be included in the PM_{10} increment inventory must met certain criteria. These include:

1) Major sources that were operating as of major source baseline data (January 6, 1975).
2) Major sources or major modifications that were constructed since the major source baseline date.

New minor sources or changes to existing minor sources were not included in this inventory since the HBRP is the first source that triggered the minor source baseline date.

Based on a review of California Air Resources Board (CARB) emissions inventory data for 2005 and 1987 (the earliest year that inventory data are available), included in Attachment 1, and discussions with the District, ten (10) facilities were identified as potentially being increment affecting facilities. These facilities, along with their 1987 and 2005 annual PM_{10} emissions, are listed in the table below. Emissions for 1987 were used as an initial indicator of historical emissions from these facilities since this is the earliest date for emissions that the CARB has available.

Table 4 - Summary of Potential PM_{10} Increment Affecting Sources

Facility Name	Location	Description	Source Constructed Prior to 1975	Current Status	1987 PM_{10} (ton/yr)	2005 PM_{10} (ton/yr)
Evergreen Pulp, Inc. (formerly Louisiana Pacific Corp.)	Samoa	Pulp Mill	Yes	Operating	889.6	113.7
Humboldt Flakeboard Panels (formerly Louisiana Pacific – Humboldt Flakeboard)	Arcata	Flakeboard Manufacturing	Yes	Operating	80.6	56.3
DG Fairhaven Power Co.	Fairhaven	Power Production	No	Operating	27.7	44.6
Pacific Lumber Co.	Scotia	Sawmill	Yes	Operating	609.1	56.8
Schmidbauer Lumber Co.	Eureka	Sawmill	Yes	Operating	18	11.2
Sierra Pacific Industries	Arcata	Sawmill	Yes	Operating	14.2	43.6
Simpson Paper Co.	Fairhaven	Pulp Mill	Yes	Shut Down	886.5	0
Simpson Timber Co. – Brainard (formerly Arcata Redwood Co.)	Eureka	Sawmill	Yes	Operating	30.1	61.5
Simpson Timber Co. - Korbel	Korbel	Sawmill	Yes	Operating	13.2	40.3
Ultrapower 3	Blue Lake	Power Production	No	Shutdown	2.4	0

Using this list of facilities as an initial starting point District files and records were reviewed to further investigate the status of these facilities as of the major source baseline date, identify facility emissions sources, source parameters, and develop emission inventory data for those sources determined to be increment consumers or expanders.

Based on the review of District information, the following were concluded:

- Four (4) of the sawmills were clearly determined to be minor sources at the major source baseline date, and therefore not considered for inclusion in the increment inventory. These facilities are Schmidbauer Lumber, Sierra Pacific Industries, Simpson Timber Co. - Brainard, and Simpson Timber Co. - Korbel.

A discussion of each of these facilities, their emission sources prior to the major source baseline date, and justification for exclusion from the increment inventory is included in Attachment 2.

- One facility, Ultrapower 3, was shut down in 2000, and since it was constructed after the major source baseline date it neither consumes or expands increment, and was dropped from further consideration.

- The Simpson Paper Co. pulp mill was shut down in 1995. This source was a major source at the major source baseline date and its baseline emissions will expand increment. PM_{10} emission sources at the mill included a power boiler, lime kiln, recovery boiler, and a smelt dissolver. Baseline PM_{10} emissions were developed for the Simpson Paper Co. pulp mill and the emissions modeled to assess the degree of increment expansion within the HBRP impact area.

- Evergreen Pulp, Inc. was a major source at the major source baseline date when it was operating as the Louisiana Pacific pulp mill. Since the major source baseline date there have been a number of plant upgrades, changes to equipment, installation of control equipment, and shutdown of several hog-fuel boilers resulting in PM_{10} emission decreases prior to being acquired by Evergreen Pulp, Inc. These emission reductions will act to expand increment. Baseline PM_{10} emissions from the Louisiana Pacific pulp mill were developed, as well as an inventory of emissions from Evergreen Pulp at the minor source baseline date. Both sources were included in the increment modeling to assess changes in increment.

- The DG Fairhaven Power Co. operates a 316 MMBtu/hr wood waste fired boiler used to produce electricity. The facility began operation in 1986 and is a major source that was constructed after the major source baseline date. As such, its emissions consume increment and were included in the increment inventory and modeled as an increment consumer.

- The Pacific Lumber Co. in Scotia is a lumber mill that was a major source at the major source baseline date. In addition to other PM emissions sources (e.g., cyclones) it operated five (5) boilers (primarily wood-waste fired) for power and steam production (rated at a total of 380,000 pounds per hour steam). The boilers were installed between 1930 and 1957.

  In 1987 the boilers were replaced with three (3) new 150,000 pound per hour steam boilers limited to a total annual average steam production of 350,000 pounds per hour. The installation of the new boilers resulted in a net decrease of 340 tons per year of PM emissions, and increased CO and NOx emissions by 577 and 186 tons per year, respectively (District "Ambient Air Quality Report", 1986). Thus, current PM_{10} emissions from the facility are lower than those at the major source baseline date, which would expand increment. However, due to the distance from the HBRP, about 31 km, rather than include it as an increment expander it was assumed to have no effect on the HBRP impact area and not included in the increment modeling.

- Humboldt Flakeboard Panels (formerly Louisiana Pacific Humboldt Flakeboard) in Arcata was a major source at the major source baseline date. Primary emission sources at the facility included an uncontrolled sander dust fired boiler and two (2) sander dust fired wood driers. In addition to these sources, there were various emission sources associated with the handling, conveyance, and processing of sawdust and wood chips (i.e., cyclones and baghouses). Since the major source baseline date the facility has undergone equipment replacement and/or modifications and installation of additional emission controls that have resulted in decreased PM_{10} emissions.

  One of the major pollution control improvement projects at the facility was in 1990 when a new furnish dryer was added and wet electrostatic precipitators (ESPs) were installed to control emissions from all three of the facility's sander dust fired wood driers. Low pressure drop scrubbers previously controlled emissions from these driers. In a 1989 District prepared chronology for a variance hearing leading up to the installation of the ESPs, the District stated that installation of the ESP would reduce PM emissions by 200 tons per year.

  Based on initial review of District records, confirmation and quantification of these and other PM emission reductions since the major source baseline date was not established. While it is expected that further review of District records would show that there has been a net decrease in PM_{10} emissions and this facility would expand increment, its emissions at the minor source baseline date were included in the increment inventory and evaluated as an increment consumer in the increment modeling.

  The Humboldt Flakeboard facility is located about 20.7 km from the HBRP, just outside of the HBRP significant impact area. The primary PM_{10} emission sources at the facility, the boiler and three dryers, were included in the increment modeling. PM_{10} emissions from the facility cyclones and baghouses were assumed to be minor and not included.

Additional details on the facilities included in the increment inventory are provided in Attachment 3.

Emissions Inventory of Increment Affecting Sources

In order to model the expected change in PM_{10} concentrations above the baseline, emissions from increment affecting sources in the project area, along with those from the proposed project, need to be determined. Under the PSD regulations emissions used in the increment analysis for existing sources are to be based on actual emissions from these sources. The baseline concentration is generally based on actual emissions representative of sources in existence on the minor source baseline date.

In practice, developing emissions for use in the increment analysis generally involves compiling an emissions inventory for two separate time periods. The first part of the inventory contains the actual emissions as of the minor source baseline. However, as discussed previously, for major sources that experienced changes in emissions resulting from construction, modification, or shutdown after the major source baseline date, the emissions as of the major source baseline date are also used. The second part of the inventory includes the emissions as of the time of review of the pending PSD permit. This inventory also contains the projected emissions of the proposed source.

Baseline Emission Inventory

Based on the above discussion and evaluation of potential PM_{10} increment affecting facilities, the facilities that were included in the PM_{10} increment emissions inventory and increment modeling analysis are summarized in Table 5 below. Figure 2 shows the locations of these facilities relative to the HBRP.

Table 5 - Summary of PM_{10} Increment Affecting Facilities Included in Increment Analysis

Facility Name	Location	Description	Period for PM_{10} Inventory	Status: PM_{10} Increment Consumer or Expander
Evergreen Pulp, Inc. (formerly Louisiana Pacific Corp.)	Samoa	Pulp Mill	Minor source baseline date[1]	Consumer
Louisiana Pacific Pulp Mill	Samoa	Pulp Mill	Major source baseline date[2]	Expander
Humboldt Flakeboard Panels (formerly Louisiana Pacific – Humboldt Flakeboard)	Arcata	Flakeboard Manufacturing	Minor source baseline date	Consumer
DG Fairhaven Power Co.	Fairhaven	Power Production	Minor source baseline date	Consumer
Simpson Paper Co.	Fairhaven	Pulp Mill (Shut Down)	Major source baseline date	Expander
HBRP	Eureka	Proposed Project	Minor source baseline date	Consumer

Notes: [1] Minor source baseline date is October 20, 2006
[2] Major source baseline date is January 6, 1975

The PSD regulations (40 CFR 52.21(b)(21(ii)) generally require that the baseline concentration be based on an average of emissions observed over the two (2) years prior to the baseline date and which are representative of normal operation. For annual emissions, the actual emissions are defined as the average rate, in tons per year, at which the unit actually emitted the pollutant during the two-year period which precedes the particular date (baseline date in this case) and which is representative of normal source operation. Under certain circumstances the regulatory authority can approve a different time period for use.

For shorter time periods, such as a 24-hour averaging period, USEPA guidance[2] (draft NSR Manual) has been to use the "maximum actual emissions rate" for short-term averaging periods. Where the maximum actual emission rate is the highest occurrence for that averaging period during the previous two years of operation. Use of the maximum rate is recommended for both the current and the baseline time periods.

In practice, it is often difficult to identify the maximum short-term emissions over a 2-year period unless CEM data are available. As such, average short-term emissions have often been used when short-term maximum actual emissions data are not available. In this analysis, because continuous short-term PM_{10} emissions are not measured at any of the baseline sources being evaluated, to the extent possible, the maximum short-term emissions were estimated based on actual measured emission rates (source tests). For sources where the emissions were reported in terms of pounds emitted per unit production or heat input (or if data are available to calculate them), the maximum short-term emission rate was calculated using this emission factor and the maximum capacity of the equipment. For cases where emissions were only reported in pounds per hour and an emission factor not developed, the measured emissions was increased by 10 percent to account for the source test not being conducted as maximum capacity, since emission testing is generally required to be conducted at or near full load conditions, typically within 90 percent of full load.

The source test data used was generally from the 2-year period before the applicable baseline date, and the highest test results were preferentially used if more than one source test was conducted during this period. If source tests were not conducted within the 2-year period preceding the baseline date, other source test data beyond the 2-year period was evaluated as being representative of actual emissions and used as appropriate. Details on specific emission sources, emission source test data available, selection of test data used, and emission calculations for each facility are provided in Attachment 3.

Actual annual average emissions for existing sources at the minor source baseline date were based on the average of the District's 2005 and 2006 annual emissions inventory (District's HARP database inventory) or estimated based on average emissions from source tests and appropriate production or operational data (e.g., annual hours of operation). For emissions from sources existing at the major source baseline date (January 6, 1975), annual average major source baseline emissions were estimated based emission source test data and production or operational information. If source tests were not conducted within the 2-year period preceding the baseline date, other source test data

[2] USEPA October 1990 Draft New Source Review Workshop Manual

beyond the 2-year period was evaluated as being representative of actual emissions and used as appropriate.

Since most, if not all, of the source test information for existing and historical increment sources is for PM rather than PM_{10}, the PM_{10} emissions were estimated using a PM_{10} adjustment factor (i.e., PM_{10} /PM fraction) for those sources whose emissions are not predominantly PM_{10}.

The maximum short term hourly and annual average PM_{10} emission rates used in the increment analysis for baseline sources are shown in Table 6. A negative emission rate denotes emissions that will expand increment.

Table 6 - PM_{10} Emissions For Baseline Emission Sources

Facility/Source	Maximum Short Term PM_{10} Emission Rates (lb/hr)	Annual Average Baseline PM_{10} Emissions (ton/yr)
Increment Consumers		
Evergreen Pulp, Inc.		
Recovery Boiler	4.6	23.6
Lime Kiln	44.16	115.64
Smelt Dissolver	20.76	29.95
Total	69.52	169.19
DG Fairhaven	21.8	28.07
Humboldt Flakeboard Panels, Inc.		
Boiler	2.04	5.09
Core Dryer	5.75	6.69
Swing Dryer	7.58	10.62
Surface Dryer	3.48	16.52
Total	18.85	38.92
Increment Expanders		
Louisiana Pacific Pulp Mill		
Recovery Furnace	-56.1	-211.4
Lime Kiln	-9.3	-35.1
East Smelt Dissolver	-13.8	-51.9
West Smelt Dissolver	-14.8	-55.7
Riley Hog Fuel Boiler	-114.3	-258.3
CE Hog Fuel Boiler	-129.1	-486.7
Total	-337.4	-1,099.1
Simpson Paper Co.		
Recovery Furnace	-167.2	-630.2
Lime Kiln	-41	-154.5
Power Boiler	-302.3	-807.9
Smelt Dissolver	35.4	-133.6
Total	-475.1	-1,726.2

Emission source parameters (e.g., stack height and diameter, exhaust gas velocity and temperature) for baseline sources used in the increment modeling were based on source test information, information in the District's HARP emissions database, or from other District file information (e.g., modeling files for permitting, AB2588 information, other emission inventory documents, etc.). PM_{10} increment modeling of baseline sources was conducted using AERMOD (discussed below), with increment consuming emissions being modeled as positive emission rates and increment expanding emissions modeled using negative emission rates. The results from this modeling are the net PM_{10} baseline concentrations in the HBRP project vicinity. These concentrations, when added to the HBRP PM_{10} increment concentrations give the total PM_{10} increment for the project, which can then be compared to the applicable maximum allowable PM_{10} increments to assess project compliance.

Table 7 - Baseline Emission Source Stack Parameters and PM_{10} Emission Rates for Increment Modeling

Facility Source	Stack Height (m)	Stack Diameter (m)	Exhaust Gas Temp. (°K)	Exhaust Gas Velocity (m/s)	Hourly Emission Rate (g/s)	Annual Average Emission Rate (g/s)
Evergreen Pulp, Inc.						
Recovery Boiler	88.4	3.23	439.3	13.2	0.580	0.679
Lime Kiln	22.9	1.48	347.9	8.9	5.564	3.327
Smelt Dissolver	63.1	1.29	353.7	8.1	2.616	0.862
DG Fairhaven						
Power Boiler	30.5	2.13	466.5	16.1	2.747	0.807
Humboldt Flakeboard Panels						
Boiler	16.8	0.77	534.9	7.9	0.257	0.146
Core Dryer	15.2	1.37	327.3	16.7	0.725	0.192
Swing Dryer	15.2	1.37	328.9	17.1	0.955	0.306
Surface Dryer	15.2	1.37	323.9	16.5	0.438	0.475
Louisiana Pacific Pulp Mill						
Recovery Furnace	88.4	3.23	358.2	16.9	-7.069	-6.081
Lime Kiln	22.9	1.48	348.7	8.1	-1.172	-1.008
East Smelt Dissolver	37.2	1.16	349.8	5.0	-1.739	-1.493
West Smelt Dissolver	37.2	1.16	350.4	5.6	-1.865	-1.602
Riley Hog Fuel Boiler	25.9	1.98	394.3	12.8	-14.402	-7.431
CE Hog Fuel Boiler	25.0	2.59	519.3	14.2	-16.267	-14.001
Simpson Paper Co.						
Recovery Furnace[a]	94.5	3.66	393.2	21.3	-21.067	-18.129
Lime Kiln[a]	94.5	3.66	393.2	21.3	-5.166	-4.445
Power Boiler[a]	94.5	3.66	393.2	21.3	-38.090	-23.241
Smelt Dissolver	42.4	1.83	335.4	8.3	-4.460	-3.843

Note: [a] The recovery furnace, lime kiln, and power boiler all exhausted through a single main stack.

PM_{10} increment emissions for the HBRP include those associated increased emissions from the proposed new sources, and the decreased in emissions from the existing units at the HBPP that will be shut down. PM_{10} emissions and stack parameters to be used in modeling HBRP increment consumption are discussed below.

Proposed Project Emission Inventory

HBRP PM_{10} Emission Sources

For modeling the 24-hour PM_{10} increment associated with emissions from the HBRP sources, the ten (10) Wärtsilä engines in diesel-firing mode were used. Maximum daily PM_{10} emissions are projected to occur under the diesel-firing scenario. Emissions from the emergency generator or fire pump engine were not included in the modeling since these emissions are negligible (0.06 pounds per day or less). Stack parameters for each engine were based on the engine operating scenario that resulted in the maximum 24-hour PM_{10} impact. From the engine screening impact analysis conducted for the AFC (refer to Section 8.1.2.6.4) this was Case 4D. Case 4D is for the engines operating at an ambient temperature of 21 ^{o}F in diesel mode under part load (50% load) conditions. PM_{10} emissions used in the increment modeling were based on the daily emission limit of 1,542 pounds per day (combined emissions from all 10 engines), per NCUAQMD direction.

For the annual average PM_{10} increment modeling of the ten HBRP engines, the stack parameters were based on the engine operating scenario that resulted in the maximum annual average PM_{10} impact. From the engine screening impact analysis conducted for the AFC (refer to Section 8.1.2.6.4) this was Case 1G. Case 1G is for the engines operating at an ambient temperature of 87 ^{o}F in gas-firing mode under full load (100% load) conditions. PM_{10} emissions used in the modeling were based on the annual emission limit of 119.8 tons per year (combined emissions from all 10 engines) based on discussion with the District. Emissions from the emergency generator or fire pump engine were not included in the increment modeling since these emissions are negligible (3.2 pounds per year or less).

The stack parameters and PM_{10} emission rates for the Wärtsilä engines used in the increment modeling are shown below. Each engine has its own exhaust stack and was modeled as an individual point source.

Table 8 – HBRP Wärtsilä Engines Stack Parameters and PM_{10} Emission Rates for Increment Modeling

Averaging Period	Stack Height (m)	Stack Diameter (m)	Exhaust Gas Temp. (^{o}K)	Exhaust Gas Velocity (m/s)	Emission Rate (g/s)	Emission Rate (lb/day)	Emission Rate (ton/yr)
24-hour	30.48	1.62	584.111	25.252	0.8097	1,542	-
Annual	30.48	1.62	663.56	27.152	0.3446	-	119.8

HBPP PM_{10} Emission Sources

The existing Humboldt Bay Power Plant consists of two (2) electric utility steam boilers (Units 1 and 2) and two (2) peaking combustion turbines (MEPPs 2 and 3). All four units will be shut down once the new engines are operational, resulting in emissions reductions. The emissions reductions associated with these existing units are detailed in the AFC (Section 8.1.2.2.1) and their PM_{10} emission rates and stack parameters provided in Table 8.1B-2, Appendix 8.1B of the AFC.

For modeling 24-hour PM_{10} increment, the existing units were modeled at loads consistent with the corresponding operational conditions of the new engines that resulted in the maximum PM_{10} impact. From the engine screening impact analysis conducted for the AFC (refer to Section 8.1.2.6.4) this was Case 4D. Case 4D is for the engines operating at an ambient temperature of 21°F in diesel mode under part load (50% load) conditions. Thus, the existing units were modeled as if they were operating under part load with Units 1 and 2 firing # 6 fuel oil and MEPPs 2 and 3 operating on diesel fuel.

For annual average PM_{10} increment modeling, the average emission rates for the historical baseline period (4th quarter 2004 through 3rd quarter 2006) were used. The existing units were modeled as if they were operating under full load with Units 1 and 2 firing natural gas and MEPPs 2 and 3 operating on diesel fuel.

The stack parameters and PM_{10} emission rates for the HBPP sources used in the increment modeling are shown below.

Table 9 - PM_{10} Increment Modeling Emission Rates and Stack Parameters for Existing HBPP Sources to be Shut Down

Averaging Period	Stack Height (m)	Stack Diameter (m)	Exhaust Gas Temp. (°K)	Exhaust Gas Velocity (m/s)	Emission Rate (g/s)	Emission Rate (lb/day)	Emission Rate (ton/yr)
24-hour Average Period, Part Load, Oil Firing in Boilers							
Unit 1	36.576	3.15	422.5	11.991	-7.281	-1,386.8	-
Unit 2	36.576	3.15	422.5	11.991	-7.673	-1,461.5	-
MEPP 2	6.528	3.767	723.0	23.026	-1.745	-332.4	-
MEPP 3	6.528	3.767	723.0	23.026	-1.745	-332.4	-
Annual Average Period, Gas Firing in Boilers							
Unit 1	36.576	3.15	408.0	11.302	-0.292	-	-10.15
Unit 2	36.576	3.15	408.0	11.302	-0.355	-	-12.34
MEPP 2	6.528	3.767	723.0	23.026	-0.072	-	-2.50
MEPP 3	6.528	3.767	723.0	23.026	-0.070	-	-2.43

These emission rates were modeled in AERMOD with negative emission rates to account for the removal of these emissions when the units are shut down.

Increment Modeling

Project Location

The proposed HBRP project site will be located at the existing Humboldt Bay Power Plant facility. The Humboldt Bay Power Plant lies along the southeastern shore of Humboldt Bay, about 4 miles (6.5 km) south-southwest of downtown Eureka, near the mouth of the Elk River. The approximate UTM coordinates of the HBRP site are 398,000 meters easting, 4,510,500 meters northing (NAD27, Zone 10). The nominal site elevation is 1 meter above mean sea level. The area in the immediate vicinity of the project site is relatively flat, with the western edge of the project area bordering on Humboldt Bay. A 600-foot tall ridge along the western edge of the Elk River Valley, called Humboldt Hill, terminates less than 1 km south-southeast of the power plant, and for dispersion purposes, constitutes the most significant terrain feature in the project vicinity. Other ridge and terrain features, running north-south, parallel to the coast, and constituting the eastern edge of the Elk River Valley, lie about 4 km inland.

Air Quality Dispersion Models

Air quality dispersion modeling was used to establish the 24-hour and annual average significant impact areas and to quantify the effects on the PM_{10} increment from increment consuming or expanding sources affecting the HBRP's significant impact area. For modeling potential PM_{10} impacts in simple and complex terrain the USEPA's AERMOD modeling system (version 07026 with the associated receptor processing program AERMAP versions 06341) was used. AERMOD was used for modeling PM_{10} impacts from the HBRP, HBPP, and other increment affecting sources in both simple and complex terrain. The Building Profile Input Program for PRIME (BPIP-PRIME version 04274) was used to model the effects of building downwash at the HBRP for use in the downwash calculations in the AERMOD.

AERMOD was run with the regulatory default option (DEFAULT), which requires the use of terrain elevation data, stack-tip downwash, sequential date checking, and the pollutant half life or decay options will not be employed. With the DFAULT option AERMOD incorporates the PRIME algorithms for the simulation of aerodynamic downwash induced by buildings. These effects are important because many of the project's emission points may be below Good Engineering Practice (GEP) stack height.

As part of the input requirements into AERMOD, a land use classification must be made. The area surrounding the Humboldt Bay Power Plant was determined to be primarily rural following the methods outlined by the Auer land use classification method for the area within a 3 km radius around the proposed project site. Rural dispersion coefficients were therefore used for the modeling.

Air Quality Modeling Meteorological Data

The meteorological data used with AERMOD for the PM_{10} increment modeling analysis are the same meteorological data that were previously used for the AFC air quality analysis that was done with the AERMOD model. The AERMOD meteorological data set was prepared using the AERMET preprocessors (Stages 1 and 2, and Stage 3). Five (5) years of meteorological data (2001 through 2005) were used in constructing the AERMOD meteorological data set. The surface meteorological data used was primarily from the National Weather Service (NWS) station located on Woodley Island, about 6 miles northeast of the project site. Since cloud cover readings are only taken during daylight hours at Woodley Island, nighttime cloud cover data from the Arcata Airport, about 17 miles north of the project site, were used. Upper air sounding data from the NWS station at the Oakland Airport were used for determining mixing height and other surface boundary layer parameters. A detailed discussion of the meteorological data and the methods used in preparing the AERMOD meteorological data is contained in Attachment 8.1B-1 (Modeling Protocol) of the AFC.

Receptor Grid Selection and Coverage

Receptor and source base elevations were determined from USGS DEM data using the 7½-minute format (30-meter spacing between grid nodes). All coordinates were referenced to UTM North American Datum 1927 (NAD27), Zone 10. The AERMOD receptor elevations were interpolated among the DEM nodes according to standard AERMAP procedures.

Cartesian coordinate receptor grids are used to provide adequate spatial coverage surrounding the project area for assessing ground-level pollution concentrations, to identify the extent of significant impacts, and to identify maximum impact locations.

For the 24-hour significant impact area analysis, a nested grid of receptors was used with a receptor spacing of 50 meters along the facility fence line and out 500 meters from the proposed facility; an intermediate receptor grid with a receptor spacing of 100-meter resolution outwards to 2.5 kilometers from the site, then a receptor spacing of 250 meter resolution outwards to 7.5 km; and a coarse receptor grid with a 500-meter receptor spacing that extended 15 km to the north, 18 km to the south, and 16 km to the east. Initially, receptors were placed west of the project extending out 15 km, with many of these receptors being over the Pacific Ocean. Initial modeling showed that concentrations over the Pacific were negligible and receptors beyond 4 km to 5 km were removed. Figure 3 shows the receptor grid used for this significance area modeling. For the annual significant impact area modeling, the same grid of receptors described above was used except that the coarse grid receptors with 500 meter spacing were not used and only receptors over the ocean within about 500 meters from the shoreline were used.

For the full increment analyses, a series of receptor grids were developed to fully represent maximum impact area(s) – coarse and refined receptor grids and a downwash grid. A coarse receptor grid was initially used to include coverage within the impact area where maximum impacts could occur. This coarse grid had a receptor spacing of 100-meter resolution from the facility outwards to 5 km, then receptors with 500-meters resolution between 5 km and about 12 km from the project site. For areas where the grids extended over the ocean, only receptors over the ocean within about 500 meters from the shoreline were used. This receptor grid is shown in Figure 4.

Based on previous modeling of the HBRP using the AERMOD model (described in the AFC), maximum short-term and annual average ground-level impacts occurred within several kilometers of the project site, in the elevated terrain areas to the south (i.e., towards the Humboldt Hill area). Thus, the fine receptor grid configuration for the modeling focused on this area.

Based on modeling results using the coarse receptor grid and those from the AFC AERMOD modeling, a fine receptor grid with receptors at 25-meter intervals was developed to blanket the elevated terrain areas south of the project where maximum impacts are were identified to occur. This resulted in a grid of receptors with 25-meter spacing that was about 1,400 meters by 1,900 meters. Additionally, a downwash receptor grid with receptor spacing of 25-meters along the facility fence line and out about 500 meters from the HBRP facility was included. Figure 5 shows the fine and downwash receptor grids used for the refined increment modeling.

AERMOD Modeling Results

Two basic modeling scenarios were evaluated; one to determine the 24-hour and annual average PM_{10} significant impact areas and the other to identify the maximum 24-hour and annual average PM_{10} increment.

To determine the significant impact areas the HBRP emission sources were modeled to obtain the maximum 24-hour (1st high) and annual average PM_{10} concentrations at each receptor within the significant impact area modeling grids for each of the five years of meteorological data. Short term and annual average emission rates and stack parameters listed in Table 8 were used. For each year modeled, the significant impact area was determined by identifying the most distant point from the project where the modeled concentration indicates a significant impact (5 $\mu g/m^3$ for 24-hour average and 1 $\mu g/m^3$ for annual average) could occur. This distance then defines the radius of the significant impact area. For the 24-hour averaging period the significant impact areas radii ranged from 14.6 km to a maximum of 18.6 km from the HBRP. The significant impact area with the largest radius (18.6 km) is shown in Figure 1.   The radius of the largest annual average significant impact area was 3.3 km.

In addition to determining the impact area for the new proposed HBRP emission sources, impact areas resulting from the net emission changes at the project due to shutting down of the existing operating generating units were also evaluated (i.e., HBRP - HBPP). The emission rates and stack parameters used in modeling the HBPP sources are shown in Table 9. For the 24-hour and annual averaging periods the largest impact areas had a radius of 3.8 km and 3 km, respectively.

In modeling the maximum PM_{10} increments, all increment affecting sources previously discussed were included. Increment consuming sources (those sources with emission increases since the major source baseline date) were modeled with positive emission rates and increment expanding sources (those sources with emission decreases since the major source baseline date) were modeled with negative emission rates. Emission rates and stack parameters for the baseline sources are shown in Table 7, while Tables 8 and 9 show the same information for the emission sources at the HRBP and HBPP, respectively.

In evaluating the 24-hour PM_{10} increment the highest second high concentration is used for comparison the maximum allowable increment. Initial increment modeling using the coarse grid receptors was used to identify the preliminary locations of maximum impact (highest 1st and 2nd highs) and to define the location and extent of the fine grid. Refined modeling using the downwash and fine grids was used to determine the location and magnitude of the maximum impact from all increment affecting sources.

The maximum 24-hour PM_{10} impact for all increment affecting sources was 24.2 $\mu g/m^3$ (highest 2nd high concentration) 1,510 meters south of the project site at UTM coordinates 398,175 meters North, 4,509,000 meters East within the fine receptor grid. The location where the maximum 24-hour average increment impact occurred is shown in Figure 6, along with the 10 $\mu g/m^3$ concentration contours in the project area. The maximum annual average PM_{10} impact for all increment affecting sources was 0.23 $\mu g/m^3$ 2,025 meters south of the project site at UTM coordinates 398,025 meters North, 4,508,485 meters East also within the fine receptor grid. Table 10 summarizes the increment modeling results for each of the five years of meteorological data used in the analysis.

Table 10 - Summary of Increment Modeling for PM_{10}

Year	24-Hour Highest 2nd High Concentration ($\mu g/m^3$)	Annual Average Concentration ($\mu g/m^3$)
2001	18.3	-0.12
2002	21.7	-0.68
2003	**24.2**	0.06
2004	21.9	**0.23**
2005	18.2	-0.10
Class II PM_{10} Increment	30	17

Based on the above modeling results, PM_{10} increment consumption by the proposed project, in combination with other PM_{10} increment affecting sources in the project region, will be lower than the maximum allowable increments for both the 24-hour and annual averaging periods.

Figures

Figure 1
24-Hour Significance Areas For HBRP Sources Alone
And For HBRP - HBPP (Shutdown Sources)

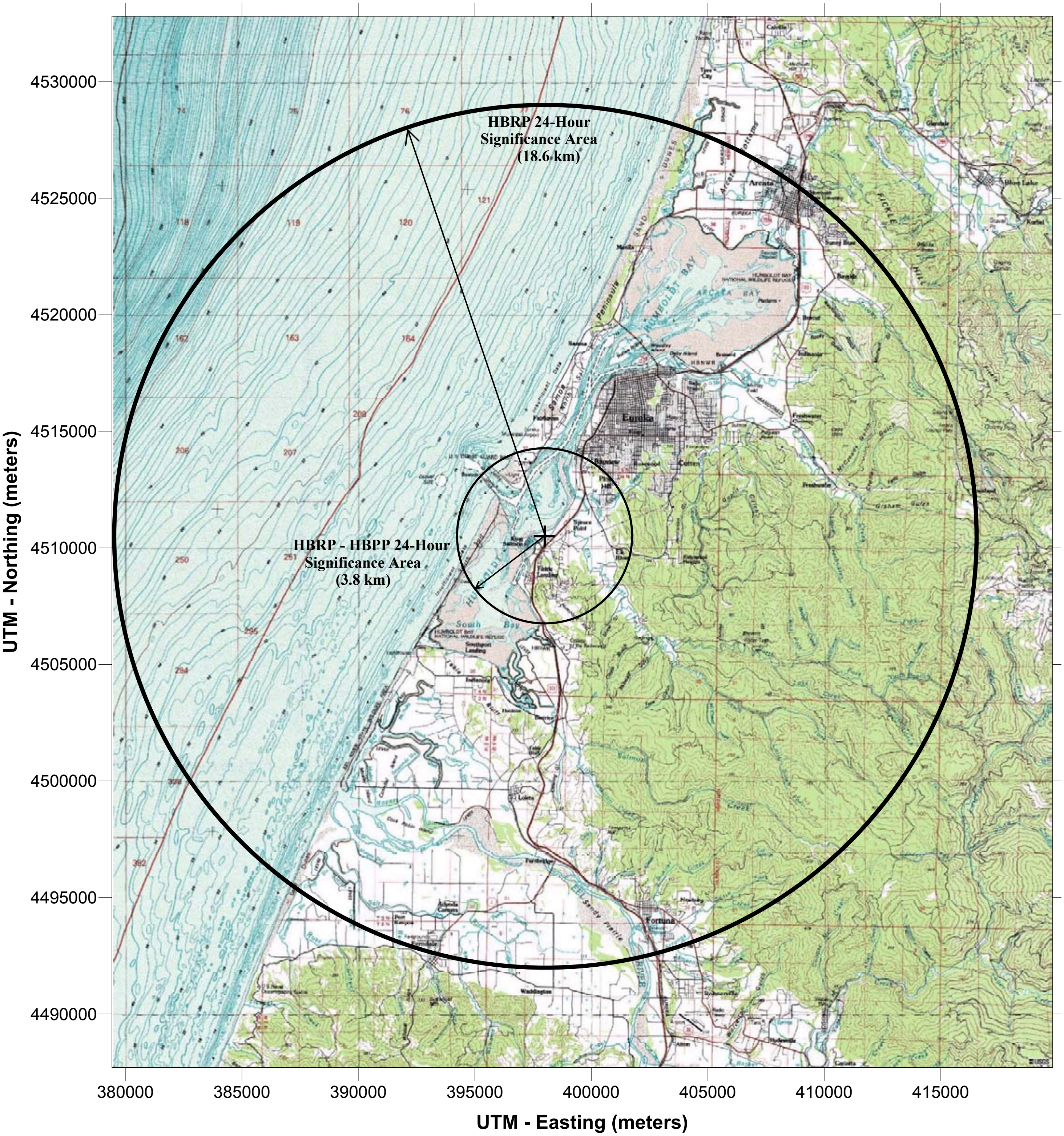


Figure 2
Increment Affecting Sources Included in the PM10 Increment Analysis

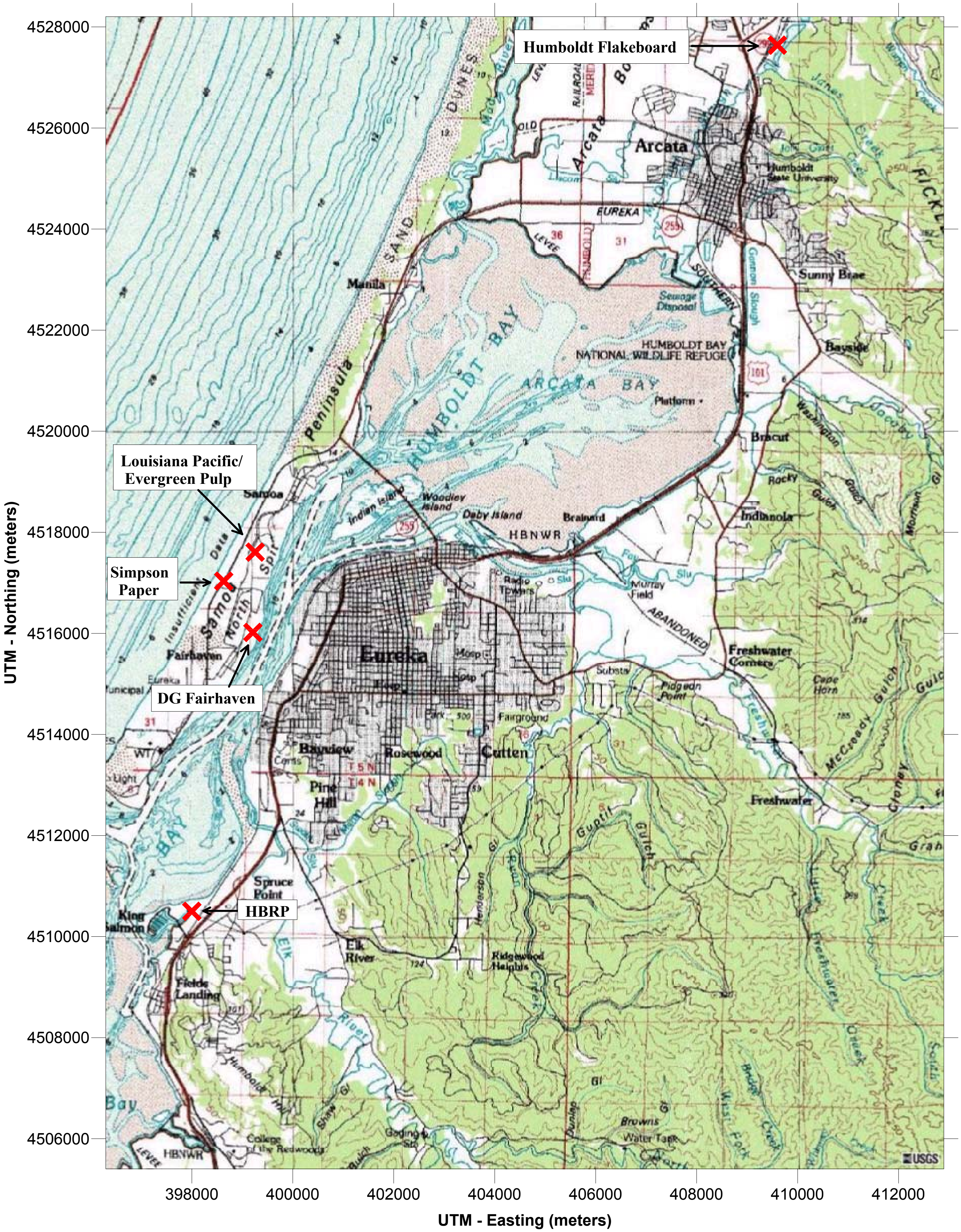


Figure 3
Receptor Grids for 24-Hour Significance Areas Modeling

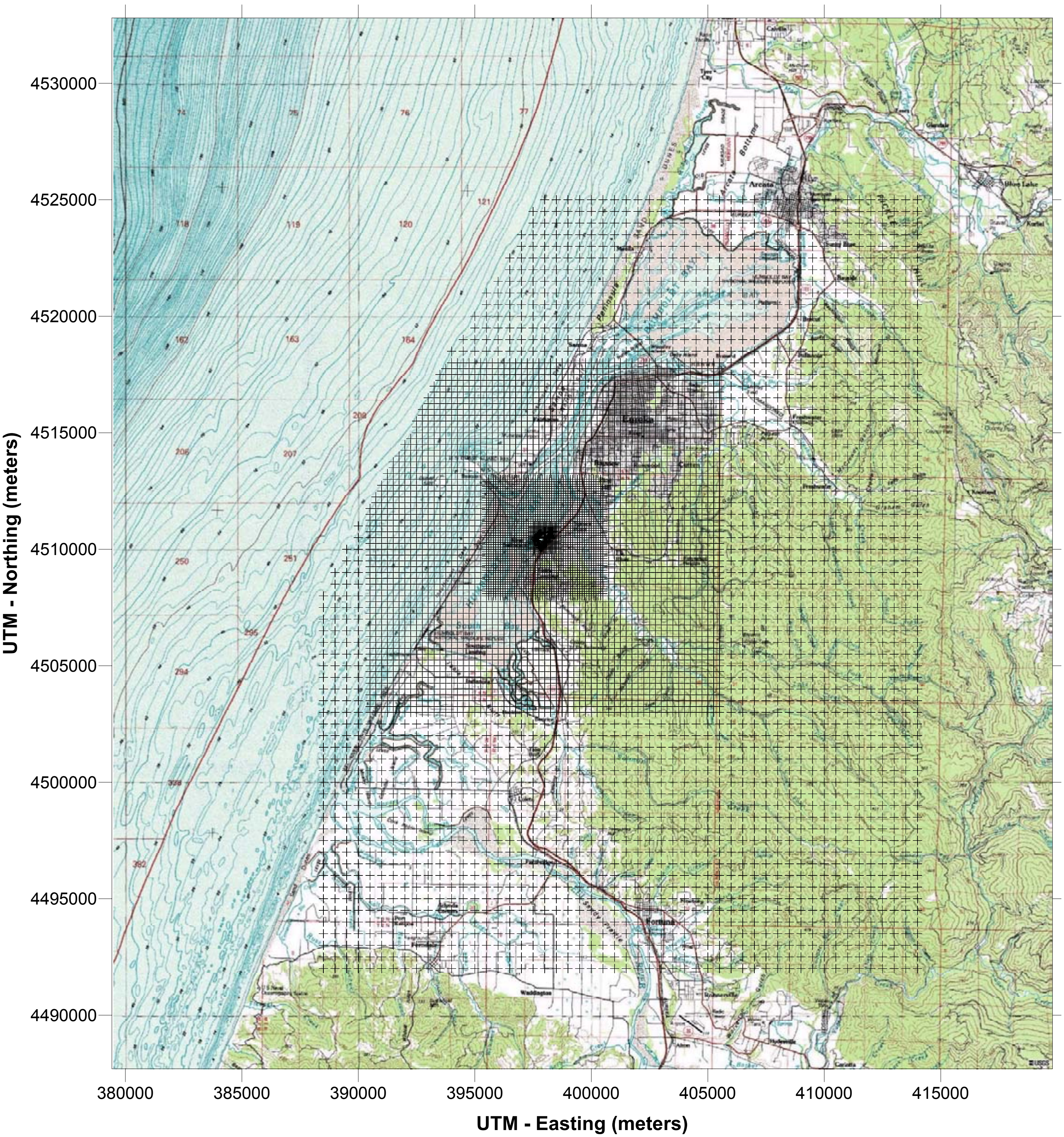


Figure 4
Coarse Receptor Grids for 24-Hour PM10 Increment Modeling

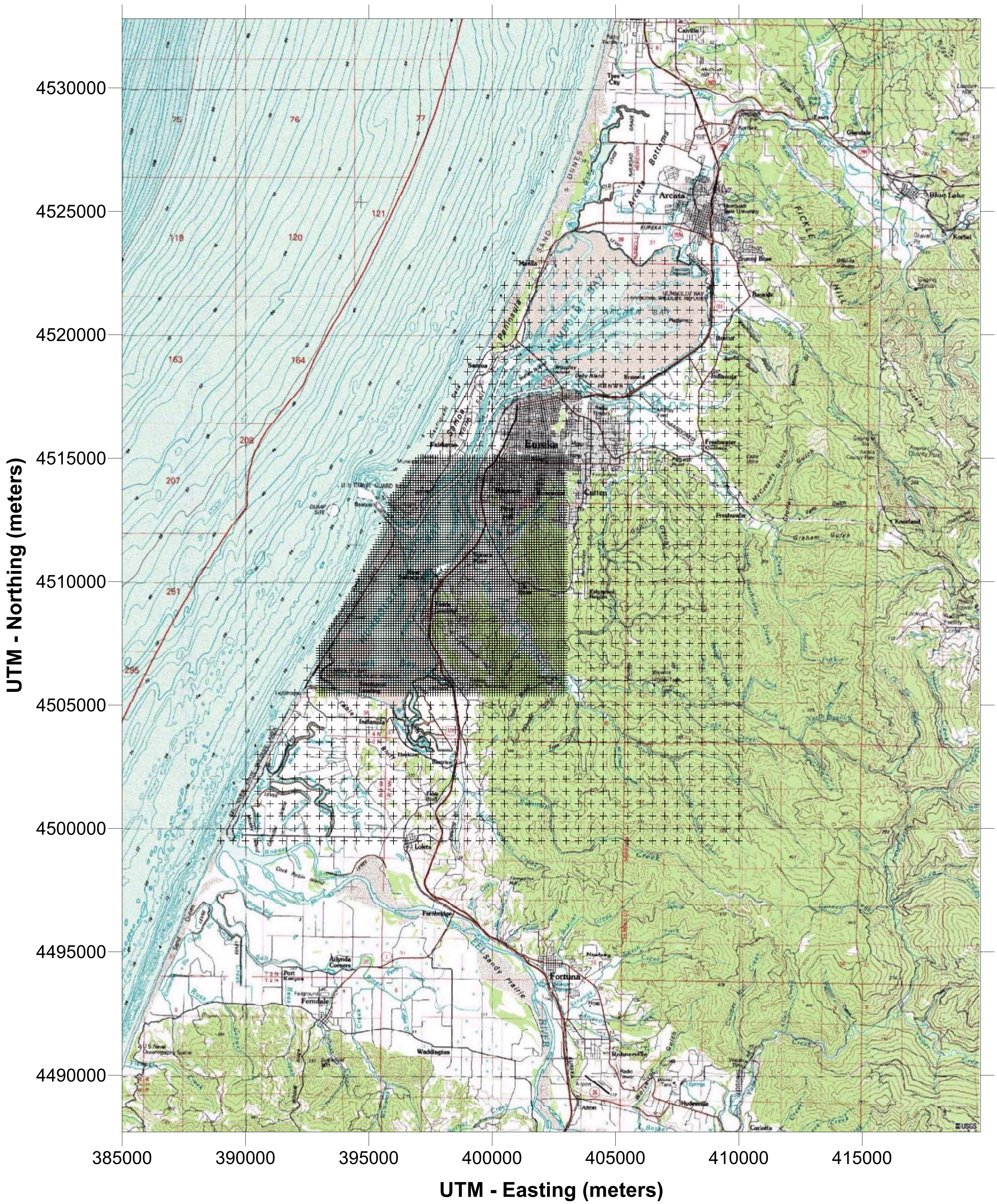


Figure 5
HBRP - PM10 Increment Modeling Fine and Downwash Grids

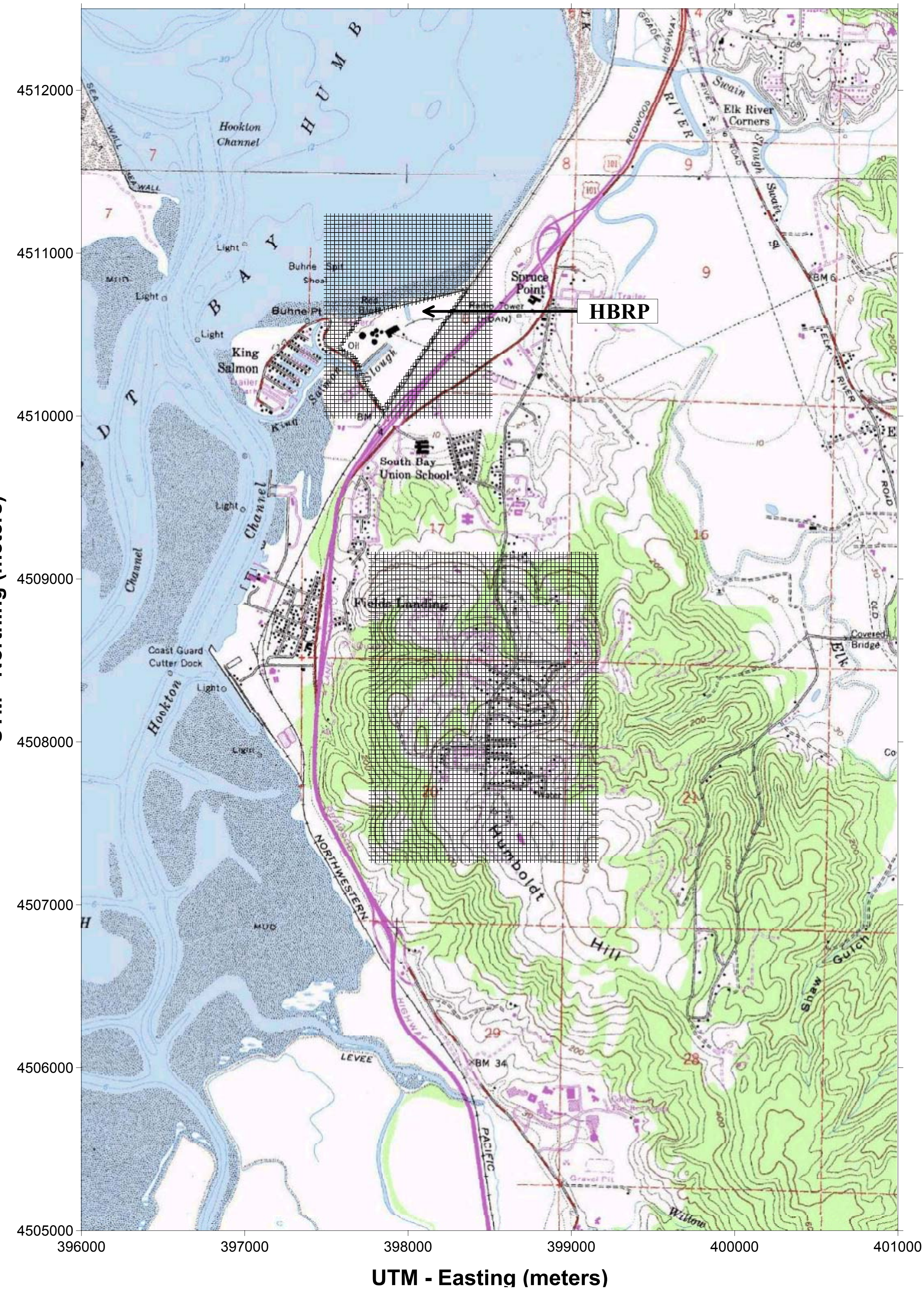
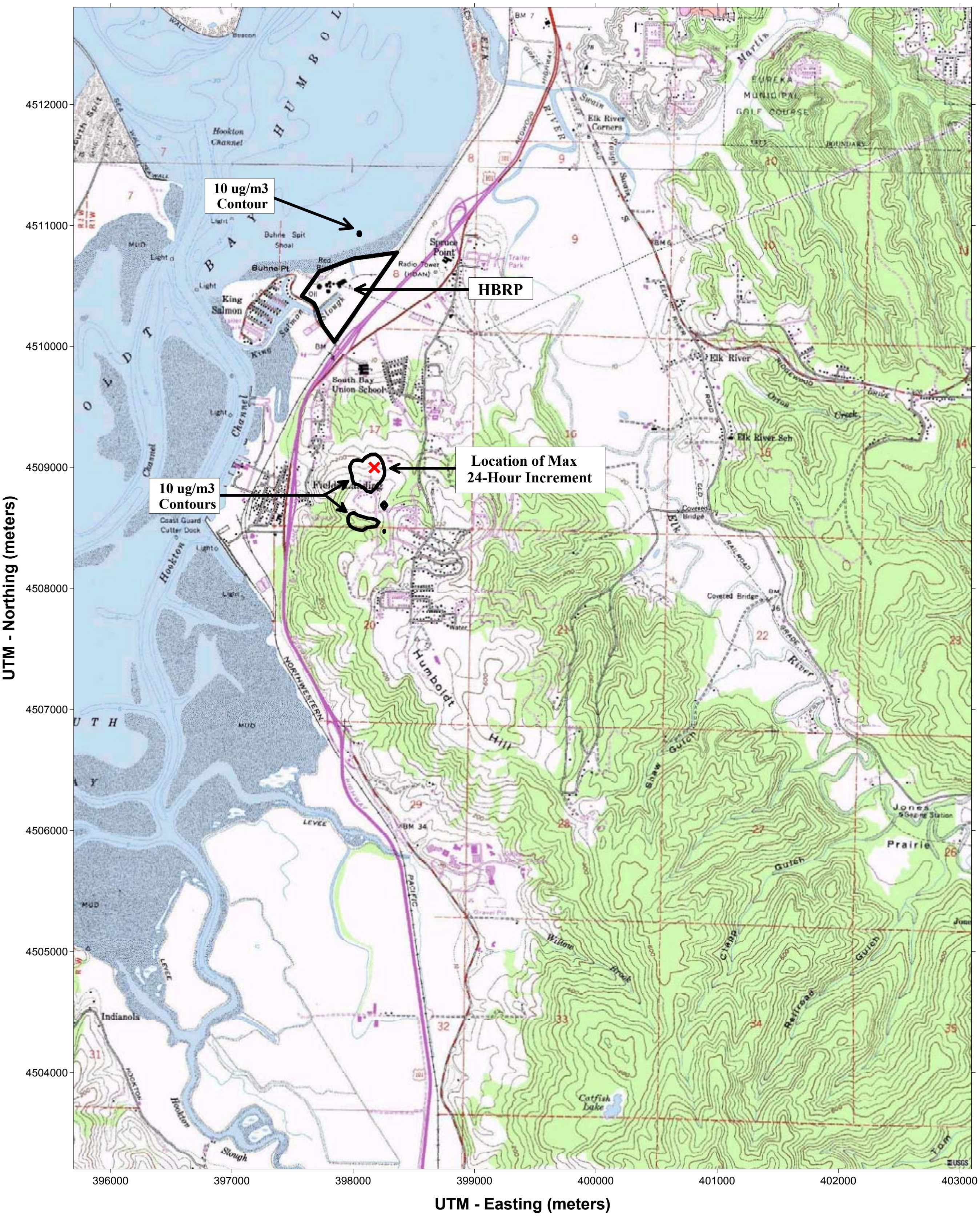


Figure 6
Location of Max. 24-hr Increment and 10 ug/m3 Concentration Contours



Attachment 1

FACILITY SEARCH RESULTS

Your Search Criteria:
Database year is 2005. County is HUMBOLDT.
Sorted by Facility Name (A to Z).
19 records returned.

Download this data as a Comma Separated Value text file.

	Fac ID	District	Facility Name	City	TOG Tons/yr	ROG Tons/yr	CO Tons/yr	NOx Tons/yr	SOx Tons/yr	PM Tons/yr	PM10 Tons/yr
1	596	North Coast Unif	Calgon Carbon Co	Blue Lak	0	0	0	0	0	0.7	0.4
2	91	North Coast Unif	Chevron Bulk Ter	Eureka	12.5	11.8	0	0	0	0	0
3	98	North Coast Unif	Eel River Sawmil	Redcrest	0	0	0	0	0	0	0
4	37	North Coast Unif	Evergreen Pulp,	Samoa	137.4	136.9	301.1	364.6	15.6	187	113.7
5	96	North Coast Unif	Fairhaven Power	Fairhave	90.1	39.5	986.6	109.2	0	44.7	44.6
6	83	North Coast Unif	Granite Construc	Arcata		0	0	0	0	1.7	0.5
7	47	North Coast Unif	Humboldt Flakebo	Arcata	46.4	44.5	0	0	0	85.4	56.3
8	737	North Coast Unif	Kernen Construct	Blue Lak	1.3	1.3	0.1	0.2	0.2	0.7	0.3
9	88	North Coast Unif	Mercer Fraser -	Cooks Va	0	0	0	0.1	0.1	0.6	0.3
10	749	North Coast Unif	Mercer Fraser -	Fortuna	0	0	0	0	0	0.5	0.2
11	81	North Coast Unif	Mercer Fraser -	Willow C	0	0	0	0.1	0.1	0.4	0.2
12	59	North Coast Unif	P G & E-humboldt	Eureka	31.5	13.9	113.3	951.1	3.5	18.1	17.9
13	61	North Coast Unif	Pacific Lumber C	Scotia	1.6	1.6	0	0	0	0.9	0.4
14	60	North Coast Unif	Pacific Lumber C	Scotia	293.2	128.6	1708.4	355.4	0	57	56.8
15	95	North Coast Unif	Schmidbauer Lumb	Eureka	6.3	2.7	0	0	0	14.5	11.2
16	84	North Coast Unif	Sierra Pacific E	Arcata	13.5	5.9	0	0	0	69.2	43.6
17	4	North Coast Unif	Simpson Timber C	Eureka	8.7	4.5	21	3.6	0	91.3	61.5
18	72	North Coast Unif	Simpson Timber C	Korbel	21.6	9.5	0	0	0	71.7	40.3
19	97	North Coast Unif	Ultrapower 3	Blue Lak	0	0	0	0	0	0	0

FACILITY SEARCH RESULTS

Your Search Criteria:
Database year is 1987. County is HUMBOLDT.
Sorted by Facility Name (A to Z).
18 records returned.

Download this data as a Comma Separated Value text file.

	Fac ID	District	Facility Name	City	TOG Tons/yr	ROG Tons/yr	CO Tons/yr	NOx Tons/yr	SOx Tons/yr	PM Tons/yr	PM10 Tons/yr
1	4	North Coast Unif	Arcata Redwood	Eureka	10.5	4.6	53	10.5	0	36.4	30.1
2	91	North Coast Unif	Chevron Usa Inc	Eureka	178.9	178.9	0	0	0	0	0
3	96	North Coast Unif	Fairhaven Power	Fairhave	147.6	64.7	737.9	147.6	0	27.8	27.7
4	81	North Coast Unif	Fo Bott,engineer	Willow C	0	0	0.2	0.7	1.8	7.5	0.9
5	87	North Coast Unif	Fo Bott,engineer	Fortuna	0	0	0.3	1.1	3.1	20.2	3.8
6	88	North Coast Unif	Fo Bott,engineer	Cooks Va	0	0	0.1	0.3	0.9	2.2	0.4
7	47	North Coast Unif	L. P. -humboldt	Arcata	356.2	348	73.2	17.8	0	127.5	80.6
8	37	North Coast Unif	Louisiana-pacifi	Samoa	520.7	363	2843.4	624.7	359.4	1128.2	889.6
9	93	North Coast Unif	Oregon Coast Tow	Eureka	61.9	61.9	0	0	0	0	0
10	59	North Coast Unif	P G & E-humboldt	Eureka	1.6	0.7	36.4	193.7	32.1	6.6	6.5
11	83	North Coast Unif	Redwood Empire A	Arcata	0	0	0.3	1.4	0	15.2	4.4
12	95	North Coast Unif	Schmidbauer Lumb	Eureka	13	5.7	65	13	0	21	18
13	84	North Coast Unif	Sierra Pacific E	Arcata	4.2	1.8	21	4.2	0	16.6	14.2
14	21	North Coast Unif	Simpson Paper Co	Fairhave	371.9	328.9	2152.4	745.3	1826.2	1035.3	886.5
15	70	North Coast Unif	Simpson Timber C	Arcata	0	0	0	0	0	22	8.8
16	72	North Coast Unif	Simpson Timber C	Korbel	8.6	3.8	43	8.6	0	22.1	13.2
17	60	North Coast Unif	The Pacific Lumb	Scotia	277.9	121.9	1389.1	277.9	0	631	609.1
18	97	North Coast Unif	Ultrapower 3	Blue Lak	85.8	37.6	428.8	85.8	0	2.4	2.4

Attachment 2

Major Source Status Review of Selected Facilities

Simpson Korbel Mill

This facility, located in Korbel, California, is a softwood lumber sawing and planing mill that also uses kiln driers for drying some of the lumber produced at the facility. The mill, originally built in 1882, was acquired by the Simpson Timber Company in 1956. Prior to 1975 the permitted emission sources at the sawmill included 9 cyclones and one 25 MMBtu/hr wood waste fired boiler. The Babcock & Wilcox boiler, permitted in 1969, was used for supplying about 15,000 pounds per hour of steam at 15 psi for use in a kiln dryer. Redwood and fir shavings were the primary fuel but fuel oil could also be used. Based on Humboldt County Air Pollution Control District (HCAPCD) notes, the wood-waste feed rate for this boiler was about 20 tons per day of dry wood. An emissions source test was conducted on the boiler in June 1974 by the HCAPCD and the measured PM emission rate was 1.7 pounds per hour.

For a source of this type to have been a major PSD source its emissions would have to have been at least 250 tons per year prior to the major source baseline date. Based on the types of emission sources at the facility prior to 1975 and the boiler source test results, this source was not a major PSD source. Additionally, there have been no major modifications to the facility since 1975. Therefore, since it was not a major PM_{10} source prior to the major source baseline date and is currently not a major source it was not included in the PM_{10} increment inventory.

Simpson Brainard Mill

The Simpson Brainard Mill, located just north of Eureka, California, is a lumber remanufacturing facility that receives lumber from other sawmills and then dries, resaws, and planes the lumber into a finished product for commercial sale. The lumber is dried in steam heated dry kilns with steam provided by a wood fired boiler. The mill was originally built in the 1940s by the Arcata Redwood Company, and acquired by the Simpson Timber Company in 1988. Prior to 1975 the permitted emission sources at the sawmill included 12 cyclones, four of which were controlled by a baghouse (installed in 1974), one 375 hp (~ 19 MMBtu/hr) wood waste fired boiler (installed in 1965), and a standby natural gas fired boiler (installed in 1965, but permit not required for it). The Birchfield wood waste fired boiler, permitted in 1969, was used for supplying about 13,000 pounds per hour of steam at 15 psi for use in kiln driers. Based on HCAPCD notes, the wood-waste feed rate for this boiler was about 1.25 tons per hour of wood. An emissions source test was conducted on the boiler in January 1974 by the HCAPCD and the measured PM emission rate was 6.1 pounds per hour.

For a source of this type to have been a major PSD source its emissions would have to have been at least 250 tons per year prior to the major source baseline date. Based on the types of emission sources at the facility prior to 1975 and the boiler source test results, this source was not a major PSD source. Additionally, there have been no major modifications to the facility since 1975. Therefore, since it was not a major PM_{10} source prior to the major source baseline date and is currently not a major source it was not included in the PM_{10} increment inventory.

Sierra Pacific Industries

This facility is a sawmill and lumber manufacturing plant located near Arcata, California. The mill receives logs and then saws and manufactures the rough cut lumber into finished products. The mill also dries lumber in steam heated dry kilns with steam provided by a boiler. The mill was originally built in the 1950s. Prior to 1975 the permitted emission sources at the sawmill included 2 cyclones and one Cleaver Brooks 6.37 MMBtu/hr oil fired boiler (installed in 1956). Based on HCAPCD inventory data, the annual oil use by the boiler was approximately 5,280 barrels per year. This boiler was replaced by a wood waste fired boiler in 1976 (after the major source baseline date). The mill currently has two wood waste fired boilers.

For a source of this type to have been a major PSD source its emissions would have to have been at least 250 tons per year prior to the major source baseline date. Based on the types of emission sources at the facility prior to 1975 and the size of the boiler, this source was not a major PSD source. Additionally, there have been no major modifications to the facility since 1975. Therefore, since it was not a major PM_{10} source prior to the major source baseline date and is currently not a major source it was not included in the PM_{10} increment inventory.

Schmidbauer Lumber Company

Schmidbauer Lumber Company owns and operates a sawmill and lumber manufacturing plant in Eureka, California. The mill receives logs and then saws and manufactures the rough cut lumber into finished products. The mill also dries lumber in steam heated dry kilns with steam provided by a boiler. Prior to 1975 the permitted emission sources at the sawmill included 4 cyclones and one Continental 21.56 MMBtu/hr natural gas fired boiler (installed in 1963) with oil standby. This boiler was replaced by a wood waste fired boiler in 1977 (after the major source baseline date).

For a source of this type to have been a major PSD source its emissions would have to have been at least 250 tons per year prior to the major source baseline date. Based on the types of emission sources at the facility prior to 1975 and the size of the boiler, this source was not a major PSD source. Additionally, there have been no major modifications to the facility since 1975. Therefore, since it was not a major PM_{10} source prior to the major source baseline date and is currently not a major source it was not included in the PM_{10} increment inventory.

Attachment 3

Facility and Emissions Data for Baseline Increment Sources

Each facility included in the baseline PM_{10} increment emissions inventory is discussed below followed by their emission calculation summaries.

DG Fairhaven - Fairhaven

Facility Description
DG Fairhaven is a power production facility that uses a wood waste fired boiler to produce steam to generate about 15 MW (gross) of electricity.

Date of Construction/Operation: 1986

Status for PM10 Increment Analysis
The facility is a major source that was constructed after the major source baseline date and prior to the minor source baseline date. It is included in the increment modeling as an increment consuming source.

Emission Source Information
PM sources at the facility include a wood waste fired boiler, cooling tower, and wood waste and ash handling systems. PM_{10} emissions from cooling tower and material handling systems were assumed to be minor and not included in the inventory. Only the boiler is included in increment modeling.

Wood waste fired boiler - 316 MMBtu/hr & 180,000 lb/hr steam on an annual basis.

PM Emission Controls
Mechanical multiclone followed by ESP

Emission Rates for PM10 Increment Analysis

Annual Average (Boiler)
Average of District's 2005 and 2006 annual emissions (from District HARP database):

Emission Source	2005 PM10 (ton/yr)	2006 PM10 (ton/yr)	Avg. Annual PM10 (ton/yr)
Wood Waste Boiler	44.700	11.448	28.074

Maximum Short-Term Emission Rate for 24-Hour Average (Boiler)
Use of October 26, 2005 emission source test[3] data (lb/MMBtu), scaled up to maximum boiler heat input of 316 MMBtu/hr.

Max. PM10 = 0.069lb/MMBtu x 316 MMBtu/hr = 21.8 lb/hr

[3] Source Test Report, 2005 Emission Compliance Tests and Relative Accuracy Test Audit, DG Fairhaven Power, Fairhaven, California. November 23, 2005. Prepared by The Avogadro Group, LLC. Note that this source test showed the PM10 emission were out of compliance with permit limit. After this date a variance was requested and approved to allow implementation of a pollution control improvement plan.

DG Fairhaven. - Minor Source Baseline Date Emissions

Representative of October 20, 2004 - October 20, 2006

Boiler Maximum Heat Input (MMBtu/hr) = 316

Short-Term Emission Based on October 2005 Source Test

Source	Temp (°F)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)	PM Emission Rate (lb/MMBtu)	Max PM[1a] Emission Rate (lb/hr)	PM10/PM[1b] Fraction	Max PM10 Emission Rate (lb/hr)
Wood Fired Boiler	380	121,861*	24.46	57849	0.04	19.19	0.069	21.80	1.00	21.80

Notes: * Calculated from source test data

[1a] Maximum short-term emissions calculated at maximum boiler heat input.

[1b] Boiler controlled by multiclone and ESP.

Annual Average Actual Emissions Based on NCUAQMD Inventory Data

Source	2005 Annual PM10 Emissions (ton/yr)	2006 Annual PM10 Emissions (ton/yr)	Average[2] Annual PM10 (ton/yr)
Wood Fired Boiler[3]	44.70	11.45	28.07

Notes: [2] Average emissions over the 2-year period 2005 - 2006. Annual average emissions provided by NCUAQMD (from HARP daabase).

Modeling Stack Parameters

Source	UTM X (m)	UTM Y (m)	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Stack Gas Temp. (°F)	Stack Gas Temp. (°K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Boiler	398633.0	4517033.0	100	30.48	7	2.13	380	466.5	52.8	16.1

Notes: Stack heights and diameters from NCUAQMD HARP database.

Base elevation = 6 m.

Louisiana Pacific Pulp Mill - Samoa

Facility Description

The Louisiana Pacific (LP) pulp mill was constructed in 1965 (by Georgia Pacific) to produce bleached pulp using the Kraft pulp process. The design capacity of the pulp mill was listed in its original permit (1969) as 500 tons per day of dry pulp, but consistently produced between 600 and 750 tons per day. In 1990, the original two recovery furnaces and smelt dissolvers were replaced with a single recovery furnace and smelt dissolver and the capacity of the mill increased to 830 tons per day of dry pulp. In 1995, LP eliminated the use of chlorine and chlorine dioxide at the pulp bleach plant. Evergreen Pulp, Inc. is the current owner and operator of the pulp mill.

Date of Construction/Operation: 1965

Status for PM10 Increment Analysis

The facility is a major source that was constructed before the major source baseline date. It is included in the increment modeling as an increment expanding source. The net increment expansion from this source is the resulting concentration due to emissions from the Evergreen Pulp facility at the minor source baseline date minus the concentration from emissions at the original LP's facility at the major source baseline date.

Facility Production Information

(see attached)

Emission Source Information

The primary PM sources at the LP pulp mill prior to 1975 included two recovery furnaces and smelt dissolvers, a lime kiln, and two (2) hog fuel boilers (Riley and CE boilers). A third hog fuel boiler (Kipper boiler) was added in 1976 and all three boilers were shut down in August 1991. There were a number of other minor PM emission sources at the facility including wood chip and sawdust material handling operations, cyclones, and other process-related sources that are not included in the emission inventory.

PM Emission Controls

- Emission controls for the recovery furnaces included contact evaporators followed by a wet ESP then a water scrubber.
- The flue gases from the lime kiln were treated with a scrubber
- The Riley boiler used a multiclone followed by a scrubber.
- The Combustion Engineering (CE) boiler used a multiclone prior to 1975. A scrubber was added in 1976.

Emission Rates for PM10 Increment Analysis

Maximum short term and annual average emissions were based on source testing conducted by the HCAPCD (see attached for source test data and emission calculations)

Louisiana Pacific Pulp Mill - Facility Operation and Production Data (1970 - 1977)

Parameter	1970	1971	1972	1973	1974	1975	1976	1977
Operation (days/year)	361	325	354	342	349	316	256	345
Annual Wood Charged (tons)	469,464	479,772	533,477	524,135	506,922	459,216	363,782	471,306
Average Wood Charged (tons per month)	39,122	39,981	44,456	43,678	42,243	38,283	36,378	39,275
Average Wood Charged (tons per operating day)	1,300	1,475	1,507	1,530	1,447	1,453	1,421	1,360
Average Pulp Production (ADTP/day)	-	-	-	685	-	-	649	-

Louisiana Pacific - Recovery Furnaces Baseline Emissions

Average Baseline Days of Operation = 346 (average of 1973 and 1974)

Historical HCAPCD Emission Source Test Data Summary (1970 - 1978) and Baseline PM10 Emissions

Date	Source Test Location	Temp (°F)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)	Max PM[1] Emission Rate (lb/hr)	Baseline[2] Annual PM Emissions (ton/yr)	Max PM10[3] Emission Rate (lb/hr)	Baseline[3] Annual PM10 Emissions (ton/yr)
2/25/70[4]	**Main Stack**	**185**	**294,000**	**39.4**	**130,000**	**0.046**	**51**	**56.1**	**211**	**56.1**	**211.4**
2/9/72	Recovery Furnace Stack	163	346,000	38.5	189,500	0.81	1,250	-	-	-	-
8/13/76	Main Stack	170	324,735*	39	166,000	0.09	128*	-	-	-	-
8/17/77	Main Stack	164	300,173*	37	160,000	0.11	148	-	-	-	-
9/14/78	Main Stack	182	313,223*	34	170,000	0.18	262	-	-	-	-

Notes: * Calculated from source test data

[1] Maximum short-term emissions calculated as 110% of average source test emissions

[2] Annual emissions calculated using average emission rate and average baseline days per year operation

[3] PM10 emissions calculated using PM10/PM percentage of 100%

[4] 2/25/70 Source Test data used as conservative estimate of the total PM emissions from the main stack

Modeling Stack Parameters

Source	UTM X (m)	UTM Y (m)	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Stack Gas Temp. (°F)	Stack Gas Temp. (°K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Main Stack	399254	4517608	290	88.4	10.6	3.2	185	358.2	55.5	16.9

Notes: Stack height and diameter from Louisiana Pacific Corp. data summary to EPA in 1973.
Base elevation = 6 m

Louisiana Pacific - Lime Kiln Baseline Emissions

Average Baseline Days of Operation = 346 (average of 1973 and 1974)

Historical HCAPCD Emission Source Test Data Summary (1970 - 1978) and Baseline PM10 Emissions

Date	Source Test Location	Temp (°F)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)	Max PM[1] Emission Rate (lb/hr)	Baseline[2] Annual PM Emissions (ton/yr)	Max PM10[3] Emission Rate (lb/hr)	Baseline[3] Annual PM10 Emissions (ton/yr)
7/9/70	Lime Kiln Exhaust	145	35,280	35.7	14,600	0.19	23.8	-	-	-	-
11/13/75[4]	**Lime Kiln Exhaust**	**168**	**29,400**	**41**	**17,500**	**0.06**	**8.6**	**9.5**	**35.7**	**9.3**	**35.0**
7/14/78	Lime Kiln Exhaust	175	34,079*	40	17,000	0.05	9.0	-	-	-	-

Notes: * Calculated from source test data

[1] Maximum short-term emissions calculated as 110% of average source test emissions

[2] Annual emissions calculated using average emission rate and average baseline days per year operation

[3] PM10 emissions calculated using PM10/PM percentage of 98.3% (AP-42 Table 10.2-4)

[4] 11/13/75 Source Test data used as conservative estimate of the total PM emissions from the lime kiln

Modeling Stack Parameters

Source	UTM X (m)	UTM Y (m)	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Stack Gas Temp. (°F)	Stack Gas Temp. (°K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Kiln Stack	399208	4517540	75	22.9	4.85	1.5	168	348.7	26.5	8.1

Notes: Stack height from CH2MHILL "Evergreen Pulp Mill Air Quality Modeling Report", 2006. Stack diameter from source test report.
Base elevation = 6 m.

Louisiana Pacific - Smelt Dissolvers Baseline Emissions

Average Baseline Days of Operation = 346 (average of 1973 and 1974)

Historical HCAPCD Emission Source Test Data Summary (1970 - 1978) and Baseline PM10 Emissions

Date	Source Test Location	Temp (^oF)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)	Max PM[1] Emission Rate (lb/hr)	Baseline[2] Annual PM Emissions (ton/yr)	Max PM10[3] Emission Rate (lb/hr)	Baseline[3] Annual PM10 Emissions (ton/yr)
5/10/76[4]	East Smelt Dissolver Stack	170	11,199*	35	6,100	0.27	14	15.4	58.0	13.8	51.9
5/10/76[4]	West Smelt Dissolver Stack	171	12,504*	35	6,800	0.25	15	16.5	62.2	14.8	55.7

Notes: * Calculated from source test data

[1] Maximum short-term emissions calculated as 110% of average source test emissions

[2] Annual emissions calculated using average emission rate and average baseline days per year operation

[3] PM10 emissions calculated using PM10/PM percentage of 89.5% (AP-42 Table 10.2-7) for smelt dissolvers with venturi scrubber

[4] 5/10/76 Source Test data used as being representative of smelt dissolver PM emissions emissions. No other data available.

Modeling Stack Parameters

Source	UTM X (m)	UTM Y (m)	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Stack Gas Temp. (^oF)	Stack Gas Temp. (^oK)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
East Stack	399303	4517651	122	37.2	3.8	1.158	170	349.8	16.5	5.0
West Stack	399289	4517657	122	37.2	3.8	1.2	171	350.4	18.4	5.6

Notes: Stack height and diameter from Louisiana Pacific Corp. data summary to EPA in 1973.
Base elevation = 6 m

Louisiana Pacific - Hog Fuel Boilers Emissions

1973 Days of Operation =	342	
1974 Days of Operation =	349	
Average Baseline Days of Operation =	346	(average of 1973 and 1974)

Riley Boiler
Historical HCAPCD Emission Source Test Data Summary (1970 - 1978) and Baseline PM10 Emissions

Date	Source Test Location	Temp (°F)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)	Max PM[1] Emission Rate (lb/hr)	Baseline[2] Annual PM Emissions (ton/yr)	Max PM10[3] Emission Rate (lb/hr)	Baseline[3] Annual PM10 Emissions (ton/yr)
3/29/73	Riley Stack	350	95,600	13.2	53,400	0.24	106	116.6	435.0	114.3	426.3
10/31/74	Riley Stack	150	72,000	23	47,300	0.05	22	24.2	92.1	23.7	90.3
Emissions[4] For 1973 & 1974	**Riley Stack**	**250**	**83,800**					**116.6**	**263.6**	**114.3**	**258.3**
11/6/74	Riley Stack	146	72,000	21	47,300	0.022	9				
3/30/76	Riley Stack	140	90,916*	20	64,000	0.03	17				

Notes:
* Calculated from source test data

[1] Maximum short-term emissions calculated as 110% of average source test emissions

[2] Annual emissions calculated using average emission rate and days per year operation

[3] PM10 emissions calculated using PM10/PM percentage of 98% (AP-42 Table 1.6-7) for boiler with scrubber

[4] Max short-term emissions from 3/29/73 and annual average estimated as average of 1973 (3/29/3 test) and 1974 (10/31/74 test) annual emissions.

Combustion Engineering Boiler
Historical HCAPCD Emission Source Test Data Summary (1970 - 1978) and Baseline PM10 Emissions

Date	Source Test Location	Temp (°F)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)	Max PM[1] Emission Rate (lb/hr)	Baseline[2] Annual PM Emissions (ton/yr)	Max PM10[3] Emission Rate (lb/hr)	Baseline[3] Annual PM10 Emissions (ton/yr)
3/22/73	**CE Stack**	**475**	**158,400**	**20.8**	**69,400**	**0.22**	**129**	**141.9**	**534.8**	**129.1**	**486.7**
8/13/75	CE Stack	400	189,135*	13	101,000	0.60	350				
1/21/1977**	CE Stack	141	112,429*	19	80,000	0.04	18				

Notes:
* Calculated from source test data
** A scrubber was installed for this boiler in 1976.

[1] Maximum short-term emissions calculated as 110% of average source test emissions

[2] Annual emissions calculated using average emission rate and average baseline days per year operation

[3] PM10 emissions calculated using PM10/PM percentage of 91% (AP-42 Table 1.6-7) for boiler with multiclone.

[4] 3/22/73 Source Test data used as conservative estimate of the PM emissions from the CE boiler.

Modeling Stack Parameters

Source	UTM X (m)	UTM Y (m)	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Stack Gas Temp. (°F)	Stack Gas Temp. (°K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Riley Boiler	399939	4518349	85	25.9	6.5	2.0	250	394.3	42.1	12.8
CE Boiler	399968	4518398	82	25.0	8.5	2.6	475	519.3	46.5	14.2

Stack height and diameter from 1990 Air Toxics Emissions Inventory Report for LP.
Base Elevation = 3 m

Evergreen Pulp, Inc. Pulp Mill - Samoa

Facility Description
Evergreen Pulp, Inc. (Evergreen) is the current owner and operator of the former Louisiana Pacific (LP) pulp mill in Samoa. The current pulp process is a chlorine and chlorine dioxide free process. There have been a number of significant changes to processes and equipment at the mill since 1975 including replacing the original two recovery furnaces and smelt dissolvers with a single recovery furnace and smelt dissolver, and shutting down three hog fuel boilers in 1991. In addition there have been other pollution control improvements at the facility since 1975.

Date of Construction/Operation: 1965

Status for PM10 Increment Analysis
The facility is a major source that was constructed before the major source baseline date. It is included in the increment modeling as an increment consuming source. The net change in increment from this source is the resulting concentration due to emissions from the Evergreen Pulp facility at the minor source baseline date minus the concentration from emissions at the original LP's facility at the major source baseline date.

Facility Production Information
(see attached)

Emission Source Information
The primary PM sources at the Evergreen pulp mill include a recovery furnace, smelt dissolver, and a lime kiln. There are a number of other minor PM emission sources at the facility including wood chip and sawdust material handling operations, cyclones, and other process-related sources that are not included in the emission inventory.

PM Emission Controls
Emission controls for the recovery furnace included contact evaporators followed by an ESP then a water scrubber.
The flue gases from the lime kiln are treated with a venturi scrubber
The smelt dissolver was controlled by a packed tower (as of 2006).

Emission Rates for PM10 Increment Analysis
Maximum short term emissions were based on source testing conducted at the facility in 2004 and 2005. Average annual emissions were calculated as the average of annual emissions for 2005 and 2006 (see attached for source test data and emission calculations)

Evergreen Pulp, Inc. - Minor Source Baseline Date Emissions
Recovery Boiler
Representative of October 20, 2004 - October 20, 2006

Recovery Boiler August 2005 Source Test Data (for Short-Term Emission Rate)

Date	Source Test Location	Temp (°F)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)	Max PM[1] Emission Rate (lb/hr)	Max PM10[2] Emission Rate (lb/hr)
8/17/05	Main Stack	331	229,679	23.48	118,892	0.004	4.18	4.60	4.60

Notes: [1] Maximum short-term emissions calculated as 110% of average source test emissions

[2] PM10 emissions calculated using PM10/PM percentage of 100%

Annual Average Actual Emissions Based on NCUAQMD Inventory Data

Source	2005 Annual PM10 Emissions (ton/yr)	2006 Annual PM10 Emissions (ton/yr)	Average[3] Annual PM10 (ton/yr)
Recovery Boiler	29.73	17.47	23.60

Notes: [3] Average annual emissions over the 2-year period 2005 - 2006.

Modeling Stack Parameters

Source	UTM X (m)	UTM Y (m)	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Stack Gas Temp. (°F)	Stack Gas Temp. (°K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Main Stack	399254	4517608	290	88.4	10.6	3.2	331	439.3	43.4	13.2

Notes: Stack height from CH2MHILL "Evergreen Pulp Mill Air Quality Modeling Report", 2006. Stack diameter from source test report.
Base elevation = 6 m.

Evergreen Pulp, Inc. - Minor Source Baseline Date Emissions
Lime Kiln
Representative of October 20, 2004 - October 20, 2006

Lime Kiln December 2004 Source Test Data (for Short-Term Emission Rate)

Date	Source Test Location	Temp (°F)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)	Max PM[1] Emission Rate (lb/hr)	Max PM10[2] Emission Rate (lb/hr)
12/28/04	Kiln Stack	166.5	32,188*	36.25	17,292	0.275	40.84	44.92	44.16

Notes: * Calculated from source test data

[1] Maximum short-term emissions calculated as 110% of average source test emissions

[2] PM10 emissions calculated using PM10/PM percentage of 98.3% (AP-42 Table 10.2-4)

Annual Average Actual Emissions Based on NCUAQMD Inventory Data

Source	2005 Annual PM Emissions (ton/yr)	2006 Annual PM Emissions (ton/yr)	Average[3] Annual PM10 (ton/yr)
Lime kiln	130.58	104.70	115.64

Notes: [3] Average emissions over 2-year period 2005-2006. PM10 emissions calculated with PM10/PM percentage of 98.3% (AP-42 Table 10.2-4)

Modeling Stack Parameters

Source	UTM X (m)	UTM Y (m)	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Stack Gas Temp. (°F)	Stack Gas Temp. (°K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Kiln Stack	399208	4517540	75	22.9	4.85	1.5	166.5	347.9	29.0	8.9

Notes: Stack height and diameter from CH2MHILL "Evergreen Pulp Mill Air Quality Modeling Report", 2006
Base elevation = 6 m.

Evergreen Pulp, Inc. - Minor Source Baseline Date Emissions

Smelt Dissolver

Representative of October 20, 2004 - October 20, 2006

Smelt Dissolver November 2004 Source Test Data (for Short-Term Emission Rate)

Date	Source Test Location	Temp (^oF)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)	Max PM[1] Emission Rate (lb/hr)	Max PM10[2] Emission Rate (lb/hr)
11/11/04	Dissolver Stack	177	22,500	44.1	10,600	0.22	19.80	21.78	20.76

Notes: [1] Maximum short-term emissions calculated as 110% of average source test emissions

[2] PM10 emissions calculated using PM10/PM percentage of 95.3% (AP-42 Table 10.2-6) for smelt dissolvers with packed tower

Annual Average Actual Emissions Based on NCUAQMD Inventory Data

Source	2005 Annual PM Emissions (ton/yr)	2006 Annual PM Emissions (ton/yr)	Average[3] Annual PM10 (ton/yr)
Lime kiln	26.71	36.14	29.95

Notes: [3] Average emissions over the 2-year period 2005 - 2006. PM10 emissions calculated using PM10/PM percentage of 95.3% (AP-42 Table

Modeling Stack Parameters

Source	UTM X (m)	UTM Y (m)	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Stack Gas Temp. (^oF)	Stack Gas Temp. (^oK)	Stack Exit Velocity (ft/sec)
Dissolver Stack	399251	4517656	207	63.1	4.23	1.3	177	353.7	26.7

Notes: Stack height and diameter from CH2MHILL "Evergreen Pulp Mill Air Quality Modeling Report", 2006

Base elevation = 6 m.

Simpson Paper Company Pulp Mill - Fairhaven

Facility Description
The Simpson pulp mill was constructed in 1966 (by Crown Simpson Pulp Company) to produce bleached pulp using the Kraft pulp process. The design capacity of the pulp mill was listed in its original permit (1969) as 500 tons per day of dry pulp, but consistently produced between 600 and 700 tons per day. The pulp mill was shut down in 1995

Date of Construction/Operation: 1966

Status for PM10 Increment Analysis
The facility was a major source that was constructed before the major source baseline date and was shut down after the major source baseline date but before the minor source baseline date. It is included in the increment modeling as an increment expanding source. All PM_{10} emissions from this facility as of the major source baseline date act to expand increment.

Facility Production Information
(see attached)

Emission Source Information
The primary PM sources at the Simpson pulp mill prior to 1975 included one recovery furnace, one smelt dissolver, a lime kiln, and one power boiler. The exhaust from the recovery boiler, lime kiln, and power boiler were all directed to a single main stack, 310 feet tall. The smelt dissolver had a separate stack. There were a number of other minor PM emission sources at the facility including wood chip and sawdust material handling operations, cyclones, and other process-related sources that are not included in the emission inventory.

PM Emission Controls
Emission controls for the recovery furnace included a contact evaporator followed by a wet ESP then a water scrubber prior to discharge to the main stack.
The flue gases from the lime kiln were treated with a venturi scrubber prior to discharge to the main stack.
The power boiler used a multiclone prior to discharge to the main stack.
The smelt dissolver used a venturi scrubber.

Emission Rates for PM10 Increment Analysis
Maximum short term and annual average emissions were based on source testing conducted by the HCAPCD (see attached for source test data and emission calculations)

Simpson Paper Company - Facility Operation and Production Data (1970 - 1978)

Parameter	1970	1971	1972	1973	1974	1975	1976	1977	1978
Operation (days/year)	351	355	357	340	351	347	330	335	297
Annual Wood Charged (tons)	433,212	480,288	471,372	450,936	514,320	485,100	436,536	446,292	354,134
Average Wood Charged (tons per month)	36,101	40,024	39,281	37,578	42,860	40,425	36,378	37,191	32,194
Average Wood Charged (tons per operating day)	1,234	1,351	1,322	1,440	1,462	1,395	1,404	1,324	1,176
Average Pulp Production (ADTP/day)	-	-	-	645	-	699	702	662	588

Simpson Paper Co. - Recovery Furnace Baseline Emissions

Average Baseline Days of Operation = 346 (average of 1973 and 1974)

Historical HCAPCD Emission Source Test Data Summary (1970 - 1978) and Baseline PM10 Emissions

Date	Source Test Location	Temp (°F)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)	Max PM[1] Emission Rate (lb/hr)	Baseline[2] Annual PM Emissions (ton/yr)	Max PM10[3] Emission Rate (lb/hr)	Baseline[3] Annual PM10 Emissions (ton/yr)
4/27/71	Recovery Furn ESP Exhaust	355	295,100	37.9	118,200	0.31	321	-	-	-	-
2/21/73[4]	Recovery Furn Scrubber Exhaust	149	239,300	36.9	129,600	0.54	601	-	-	-	-
10/12/73[5]	**Recovery Furn Scrubber Exhaust**	**163**	**232,700**	**30.1**	**135,800**	**0.15**	**152**	**167.2**	**630**	**167.2**	**630.2**
9/11/75[6]	Recovery Furn Scrubber Exhaust	171	276,146*	41.7	134,700	0.02	22.7	-	-	-	-

Notes:
* Calculated from source test data
[1] Maximum short-term emissions calculated as 110% of average source test emissions
[2] Annual emissions calculated using average emission rate and average baseline days per year operation
[3] PM10 emissions calculated using PM10/PM percentage of 100%
[4] Source test was conducted during a reported breakdown of the ESP (not used)
[5] 10/12/73 Source Test data used as estimate of the total PM emissions from the main stack
[6] Source test was conducted after modifications to the ESP were made in late 1974

Modeling Stack Parameters (for combined emissions from recovery boiler, lime kiln, and power boiler)

Source	UTM X (m)	UTM Y (m)	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Stack Gas Temp. (°F)	Stack Gas Temp. (°K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Main Stack	399210	4516020	310	94.5	12	3.658	248	393.2	69.9	21.3

Notes: Stack height and diameter from Crown Simpson data summary to EPA in 1973.
Base elevation = 3 m

Simpson Paper Co. - Lime Kiln Baseline Emissions

Average Baseline Days of Operation = 346 (average of 1973 and 1974)

Historical HCAPCD Emission Source Test Data Summary (1970 - 1978) and Baseline PM10 Emissions

Date	Source Test Location	Temp (°F)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)	Max PM[1] Emission Rate (lb/hr)	Baseline[2] Annual PM Emissions (ton/yr)	Max PM10[3] Emission Rate (lb/hr)	Baseline[3] Annual PM10 Emissions (ton/yr)
5/19/70	Kiln Exhaust to Main Stack	165	31,100	36.1	14,210	0.16	18.8	-	-	-	-
1/26/73[4]	**Kiln Exhaust to Main Stack**	**158**	**33,050**	**31.7**	**18,900**	**0.23**	**37.9**	**41.7**	**157.1**	**41.0**	**154.5**
6/11/75	Kiln Exhaust to Main Stack	166	37,358*	27	23,000	0.11	23	-	-	-	-

Notes: * Calculated from source test data

[1] Maximum short-term emissions calculated as 110% of average source test emissions

[2] Annual emissions calculated using average emission rate and average baseline days per year operation

[3] PM10 emissions calculated using PM10/PM percentage of 98.3% (AP-42 Table 10.2-4)

[4] 1/26/73 Source Test data used as estimate of the total PM emissions from the lime kiln

Modeling Stack Parameters (for combined emissions from recovery boiler, lime kiln, and power boiler)

Source	UTM X (m)	UTM Y (m)	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Stack Gas Temp. (°F)	Stack Gas Temp. (°K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Main Stack	399210	4516020	310	94.5	12	3.7	248	393.2	69.9	21.3

Notes: Stack height and diameter from Crown Simpson data summary to EPA in 1973.
Base elevation = 3 m

Simpson Paper Co. - Smelt Dissolver Baseline Emissions

Average Baseline Days of Operation = 346 (average of 1973 and 1974)

Historical HCAPCD Emission Source Test Data Summary (1969 - 1978) and Baseline PM10 Emissions

Date	Source Test Location	Temp (°F)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)	Max PM[1] Emission Rate (lb/hr)	Baseline[2] Annual PM Emissions (ton/yr)	Max PM10[3] Emission Rate (lb/hr)	Baseline[3] Annual PM10 Emissions (ton/yr)
12/29/69[4]	**Dissolver Vent**	**144**	**46,000**	**15.6**	**31,300**	**0.13**	**36**	**39.6**	**149.3**	**35.4**	**133.6**
4/27/76	Dissolver Vent	208	26,732*	29	15,000	0.28	67	73.7	277.8	66.0	248.6

Notes: * Calculated from source test data

[1] Maximum short-term emissions calculated as 110% of average source test emissions

[2] Annual emissions calculated using average emission rate and average baseline days per year operation

[3] PM10 emissions calculated using PM10/PM percentage of 89.5% (AP-42 Table 10.2-4) for smelt dissolvers with venturi scrubber

[4] 12/29/69 Source Test data used as estimate of smelt dissolver PM emissions emissions.

Modeling Stack Parameters

Source	UTM X (m)	UTM Y (m)	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Stack Gas Temp. (°F)	Stack Gas Temp. (°K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Dissolver Stack	399245	4516071	139	42.4	6	1.8	144	335.4	27.1	8.3

Notes: Stack height and diameter from Crown Simpson data summary to EPA in 1973.
Base elevation = 3 m

Simpson Paper Co. - Power Boiler Emissions

1973 Days of Operation =	340	
1974 Days of Operation =	351	
Average Baseline Days of Operation =	346	(average of 1973 and 1974)

Power Boiler

Historical HCAPCD Emission Source Test Data Summary (1970 - 1978) and Baseline PM10 Emissions

Date	Source Test Location	Temp (°F)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)	Max PM[1] Emission Rate (lb/hr)	Baseline[2] Annual PM Emissions (ton/yr)	Max PM10[3] Emission Rate (lb/hr)	Baseline[3] Annual PM10 Emissions (ton/yr)
6/4/70	Boiler exhaust fan suction duct	390	147,500	15.9	72,000	0.14	153	-	-	-	-
11/12/71	Boiler exhaust fan suction duct (~ 65% load)	417	158,000	15.1	67,500	0.16	270	-	-	-	-
6/19/73	Boiler exhaust fan suction duct	439	192,600	16.7	100,500	0.4	302	332.2	1,232	302.3	1,121
10/17/74	Boiler exhaust fan suction duct	415	132,797*	12	70,500	0.21	129	141.9	543.3	129.1	494.4
Emissions[4] For 1973 & 1974	**Boiler exhaust fan suction duct**	**427**	**162,699**	-	-	-	-	**332.2**	**887.8**	**302.3**	**807.9**
2/10/77	Boiler exhaust fan suction duct	420	168,891*	16	85,100	0.21	151	-	-	-	-
Notes:	* Calculated from source test data				82,025						

[1] Maximum short-term emissions calculated as 110% of average source test emissions

[2] Annual emissions calculated using average emission rate and average baseline days per year operation

[3] PM10 emissions calculated using PM10/PM percentage of 91% (AP-42 Table 1.6-7) for boiler with multiclone.

[4] Max short-term emissions from 6/19/73 and annual average estimated as average of 1973 (6/19/3 test) and 1974 (10/171/74 test) annual emissions.

Modeling Stack Parameters (for combined emissions from recovery boiler, lime kiln, and power boiler)

Source	UTM X (m)	UTM Y (m)	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Stack Gas Temp. (°F)	Stack Gas Temp. (°K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Main Stack	399210	4516020	310	94.5	12	3.7	248	393.2	69.9	21.3

Notes: Stack height and diameter from Crown Simpson data summary to EPA in 1973.
Base elevation = 3 m

Simpson Paper Co. - Main Stack Exhaust Parameters

Recovery boiler, lime kiln, power boiler, black liquor oxidizer, and secondary oxidizer all exhaust through main stack

Historical HCAPCD Emission Source Test Data Summary (1970 - 1978)

Date	Source Test Location	Temp (^oF)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)
10/4/77	Main Stack Exhaust	248	474,397*	33	237,000	-	-

Notes: * Calculated from source test data

Modeling Stack Parameters (for combined emissions from recovery boiler, lime kiln, and power boiler)

Source	UTM X (m)	UTM Y (m)	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Stack Gas Temp. (^oF)	Stack Gas Temp. (^oK)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Main Stack	399210	4516020	310	94.5	12	3.7	248	393.2	69.9	21.3

Notes: Stack height and diameter from Crown Simpson data summary to EPA in 1973.
Base elevation = 3 m

Humboldt Flakeboard Panels, Inc.

Facility Description

Humboldt Flakeboard Panels, Inc. (formerly Louisiana Pacific Humboldt Flakeboard) in Arcata, California produces particleboard. Wood waste material is refined into fine wood particles which are then dried to remove excess moisture prior to mixing with resinous adhesives. The resulting material is then formed into mats and pressed into various thicknesses of particleboard. The panels are then sent to a finishing area for surface preparation and sizing prior to packaging and shipping.

Date of Construction/Operation: Prior to 1975

Status for PM10 Increment Analysis

The facility is a major source that was constructed before the major source baseline date and continues to operate. It is included in the increment modeling as an increment consuming source.

Emission Source Information

PM sources at the facility include a sanderdust fired boiler, three sanderdust fired dryers, and various wood-waste material handling systems. PM_{10} emissions from the material handling systems assumed to be minor and not included in the inventory. Only the boiler and dryers are included in increment modeling.

PM Emission Controls

The boiler is uncontrolled and the three dryers use multiclones followed by wet ESPs

Emission Rates for PM10 Increment Analysis

Maximum short term emissions were based on source testing conducted at the facility in 2005. Average annual emissions were calculated as the average of annual emissions for 2005 and 2006 (see attached for source test data and emission calculations)

Humboldt Flakeboard Panels, Inc. - Minor Source Baseline Date Emissions

Representative of October 20, 2004 - October 20, 2006

2005 Days of Operation = 229
2006 Days of Operation = 229
Average Baseline Days of Operation = 229 (average of 2005 and 2006)

Short-Term Emission Based on December 2005 Source Test

Source	Pressure (in. Hg)	Temp (°F)	Flow at Temp (acfm)	Percent Water	Dry Flow (dscfm)	PM Loading (gr/dscf)	PM Emission Rate (lb/hr)	Max PM[1a] Emission Rate (lb/hr)	PM10/PM[1b] Fraction	Max PM10 Emission Rate (lb/hr)
Wood Fired Boiler	30.09	503.1	7,838*	9.77	3898	0.062	2.06	2.27	0.90	2.04
Core Dryer	30.2	129.4	52,204*	14.28	40,460	0.015	5.23	5.75	1.0	5.75
Swing Dryer	30.18	132.3	53,661*	16.62	40,229	0.02	6.89	7.58	1.0	7.58
Surface Dryer	30.12	123.4	51,731*	13.63	40,705	0.009	3.17	3.48	1.0	3.48

Notes: * Calculated from source test data. Source test conducted December 12 - 15, 2005.
[1a] Maximum short-term emissions calculated as 110% of average source test emissions
[1b] Boiler is uncontrolled & dryers are controlled by multiclones & wet ESPs

Annual Average Actual Emissions Based on NCUAQMD Inventory Data & Dec. 2005 Source Test Data

Source	2005 Annual PM10 Emissions (ton/yr)	2006 Annual PM10 Emissions (ton/yr)	Average[2] Annual PM10 (ton/yr)
Wood Fired Boiler[3]	5.09	5.09	5.09
Core Dryer[4]	6.22	7.15	6.69
Swing Dryer[4]	9.86	11.37	10.62
Surface Dryer[4]	15.34	17.69	16.52

Notes: [2] Average annual emissions over the 2-year period 2005 - 2006.
[3] Annual PM10 emissions from the boiler based on the average lb/hr emission rate from the 2005 source test and days of operation.
[4] Annual average emissions provided by NCUAQMD.

Modeling Stack Parameters

Source	UTM X (m)	UTM Y (m)	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Stack Gas Temp. (°F)	Stack Gas Temp. (°K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Boiler	409600.1	4527640.1	55	16.76	2.54	0.77	503.1	534.9	25.8	7.9
Core Dryer	409644.4	4527638.2	50	15.24	4.50	1.37	129.4	327.3	54.7	16.7
Swing Dryer	409640.4	4527632.7	50	15.24	4.50	1.37	132.3	328.9	56.2	17.1
Surface Dryer	409637.4	4527627.2	50	15.24	4.50	1.37	123.4	323.9	54.2	16.5

Notes: Stack heights and diameters based on source test data, NCUAQMD information, and 1992 Air Toxics Emission Inventory Report (Sassenrath, 1992)
Base elevation = 12 m.

USDA United States Department of Agriculture | Forest Service | Pacific Southwest Region

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File Code: 2580
Date: OCT 16 2007

Rick Martin Air Pollution Control Officer
North Coast Unified Air Quality Management District
2300 Myrtle Ave
Eureka, CA 95501

RECEIVED
OCT 20 2007
By OM

Dear Mr. Martin:

Thank you for the opportunity to review and comment on the proposed Humboldt Bay Repowering Project (HBRP) Class I Impact Analysis. The applicant is Pacific Gas & Electric Company. The analysis was prepared by Sierra Research (Sacramento, CA office). The following comments reflect the Forest Service review of the analysis.

The nearest Class I PSD area (Redwood National Park) is 42 kms from the project. Table 1 below shows the distance to Class I areas that the applicant has analyzed.

Table 1
Class 1 Area Distances from the Project Site

Class 1 Area	Distance km	Distance miles
Redwood NP	42	26
Marble	100	62
Yolla Bolly	114	71

The Humboldt Bay Repowering Project consists of ten new Wartsila Model 18V50DF engine/generator sets (total capacity approximately 163 MW) at the Humboldt Bay Power Plant near Eureka, CA. This new equipment will replace two natural gas-fired steam boilers (rated at 50 MW each) and two distillate-fired peaking turbines (rated at 15 MW each), so there is a small net capacity increase associated with the project. The new engines are intended to operate primarily on natural gas, but have the capability of using ultra-low sulfur diesel fuel when natural gas delivery is disrupted. It is estimated that diesel fuel could be used for up to 50 hours per year of operation (down from an original estimate of 800 hours per year). The replacement of the equipment will cause an emission reduction of approximately 573 tons per year (TPY) of nitrogen oxide (NO_x), and an increase in emissions of sulfur dioxide (SO_2) of 0.8 TPY, and 158 TPY of $PM_{10}/PM_{2.5}$.

The proposed modeling analysis was conducted at all three Class I areas using the CALPUFF model in the screening mode. Since Redwood National Park also lies less than 50 km from the project site, a plume analysis with VISCREEN was also employed. However, PSD increment, visibility and acid deposition impacts were still calculated using CALPUFF at Redwood National Park

The National Park Service re-modeled the plume impacts of the new sources alone for Redwood National Park. The results of this analysis indicate impacts below the VISCREEN Delta E and contrast thresholds with a Delta E of 1.986 and a contrast of 0.015. We therefore do not anticipate any perceptible plume impacts at Marble and Yolla Bolly wilderness Class I areas that are farther than Redwood National Park.

Because the North Coast Unified Air Quality Management District will limit oil firing to only 50 hours per year, we do not request that Sierra Research conduct a VISCREEN analysis for emissions from oil firing.

Considering the emission reductions associated with the units being shut down, the total amount of annual emissions of NO_x, SO_2 and $PM_{10}/PM_{2.5}$ from the new engines, and the distance to Marble and Yola Bolly, we will not ask Sierra Research to conduct a re-analysis with the EPA CALPUFF refined model. We agree with comments from National Park Service that for future uniform haze modeling analyses, the use of the CALPUFF-Lite model, used by Sierra Research in this case, is no longer an accepted modeling method. CALPUFF-Lite is currently not listed as an approved modeling procedure in the EPA Air Quality Modeling Guidelines (40 CFR 51, Appendix W).

The Forest Service encourages use of clean technology whenever possible and feasible. We hope the facility follows its policy of applying new technology in the future as it becomes available to maintain the air quality at healthy levels and conducive to the environment. Forest Service Region 5 (Pacific Southwest Region) is also deeply concerned about increased green house gas emissions. We would like information about green house gases that are being emitted at the facility and if the company is considering any offsets on a volunteer basis. This information will not be considered in the permit review.

Thanks again for the opportunity to be involved in an early review process. If you have any questions, please contact Trent Procter of my staff at 559-784-1500, x1114 / tprocter@fs.fed.us or Dr. Suraj Ahuja at 530-521-7394 / sahuja@fs.fed.us.

Sincerely,

Beth G. Pendleton, for

VICKI A. JACKSON
Acting Regional Forester

Ramco Generating Two

61 AVENIDA DE ORINDA, SUITE 35
ORINDA, CA 94563
Tel: (925) 258-9829 Fax: (925) 258-9802

February 24, 2006

Michael Scheible
Deputy Executive Officer
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

Dear Mr. Scheible:

We appreciated the opportunity to meet with you on February 2 to present some of the reasons why clean and efficient reciprocating engine technology is a viable solution to the energy needs in some California markets. One such market is the Eureka/Humboldt Bay area. If this technology were selected to replace the existing power plant, it would consist of natural gas engines with Diesel pilot injection. The engines would also have the ability to be fired on 100% Diesel in the event of a natural gas curtailment.

Additionally, the project would comply with the ATCM for Stationary Compression Ignition Engines. In pilot injection mode, the engines operate significantly similar to the theoretical Otto Cycle, and are therefore not "compression ignition engines" as defined in the ATCM. Thus, the ATCM would not apply to the engines while operating in pilot injection mode. In 100% Diesel mode, the engines would be subject to the emission limits, testing and maintenance operational limits, monitoring, and record keeping for "emergency standby engines." This is contingent upon limiting operation in 100% Diesel mode only during periods of natural gas curtailment, in accordance with the definition of "emergency use" in the ATCM.

We are seeking CARB's concurrence with the regulatory analysis of the ATCM summarized above. The replacement of the existing plant with an efficient, true intermediate-load plant will result in substantial reductions in both air emissions and fuel consumption. Thank you again for your time and consideration of this issue.

Sincerely,

Kent L. Fickett
Co-CEO and President
Ramco Generating Two, Inc.

cc: Greg Lamberg, PG&E
Lorraine Paskett, PG&E
Gary Rubenstein, Sierra Research

Air Resources Board

Alan C. Lloyd, Ph.D.
Agency Secretary

Robert F. Sawyer, Ph.D., Chair
1001 I Street • P.O. Box 2815
Sacramento, California 95812 • www.arb.ca.gov

Arnold Schwarzenegger
Governor

March 10, 2006

Mr. Kent L. Fickett
Co-CEO and President
Ramco Generating Two, Inc.
61 Avenida De Orinda, Suite 35
Orinda, California 94563

Dear Mr. Fickett:

In response to the request in your letter of February 24, 2006, the Air Resources Board staff conducted a regulatory analysis to determine if your dual-fueled diesel pilot ignition engine technology was subject to the requirements of the Stationary Compression Ignition Engine Airborne Toxic Control Measure (ATCM). Based on our analysis of the data you supplied, we concur that:

1. The requirements in the Stationary Diesel Engine ATCM do not apply to the dual-fuel diesel pilot ignition engines when operating in the natural gas/diesel pilot mode.

2. The requirements in the Stationary Diesel Engine ATCM for Emergency Standby Engines do apply to the dual-fuel diesel pilot ignition engines when operating in the diesel-only mode.

If you have further questions regarding this matter, please contact Mr. Dan Donohoue, Chief of the Emissions Assessment Branch, Stationary Source Division at (916) 322-6023.

Sincerely,

Michael H. Scheible

Michael H. Scheible
Deputy Executive Officer

cc: Dan Donohoue, Chief
Emissions Assessment Branch

Air Resources Board

Robert F. Sawyer, Ph.D., Chair
1001 I Street • P.O. Box 2815
Sacramento, California 95812 • www.arb.ca.gov

Alan C. Lloyd, Ph.D.
Agency Secretary

Arnold Schwarzenegger
Governor

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By________

March 10, 2006

Mr. Kent L. Fickett
Co-CEO and President
Ramco Generating Two, Inc.
61 Avenida De Orinda, Suite 35
Orinda, California 94563

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Sincerely,

Michael H. Scheible

Michael H. Scheible
Deputy Executive Officer

cc: Dan Donohoue, Chief
Emissions Assessment Branch

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Draft February 17, 2006
Applicability of the Stationary Diesel Engine ATCM
To Humboldt Power Plant Project
[Contains information that was requested to be held "Confidential"]

Issue: Does the Stationary Diesel Engine ATCM apply to the duel-fueled engines proposed for use in the Humboldt Power Plant Project?

Conclusions:
1. The requirements in the Stationary Diesel Engine ATCM do not apply to the dual-fuel diesel pilot engines when operating in the natural gas/diesel pilot mode.

2. The requirements in the Stationary Diesel Engine ATCM for Emergency Standby Engines do apply to the dual-fuel diesel pilot engines when operating in the diesel-only mode.

Background:

On February 2, 2006, ARB staff met with representative from Ramco, Black Hills, Sierra Research, and PG&E to discuss the applicability of the Stationary Diesel Engine ATCM to a potential Humboldt Power Plant Project. The proposal is to install 10 Wartsila 50DF dual-fueled engines (combined power 165 MW) to replace PG&E Humboldt Power Plant (two 52 MW boilers and two combustion turbines). The Wartsila 50DF engines would use natural gas as the primary fuel. A small quantity of diesel fuel is injected into the combustion chambers as pilot fuel. The diesel fuel ignites by compression ignition and serves as the ignition source for the natural gas and air mixture. The pilot fuel amounts to about 1% of the full-load fuel consumption. When gas supply is interrupted the engine would switch to 100% diesel fuel.

The key issue was whether or not these engines would be subject to the requirements of the Stationary Diesel Engine ATCM, and if so, what standards would the engines have to meet.

Finding 1: Under the current project design and when operating on natural gas with diesel pilot injection, the Wartsila 50DF engine would not be subject to the requirements in the Stationary Diesel Engine ATCM.

The Stationary Diesel Engine ATCM applies to stationary compression ignition engines. Under this regulation, "'Compression Ignition Engine' means an internal combustion engine with operating characteristics significantly similar to the theoretical diesel combustion cycle. The regulation of power by controlling fuel supply in lieu of a throttle is indicative of a compression ignition engine."

The Wartsila 50DF engine, when operating in the natural gas/diesel pilot mode, has operating characteristics more closely related to an Otto cycle engine than a

United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

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IN REPLY REFER TO:

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By Scanned rw

August 29, 2007

N3615 (2350)

Rick Martin, Air Pollution Control Officer
North Coast Unified Air Quality Management District
2300 Myrtle Avenue
Eureka, California 95501

Dear Mr. Martin:

We have reviewed the Class I Impact Analysis report prepared by Sierra Research for the Humboldt Bay Repowering Project (HBRP) located near Eureka, California. We have also reviewed the California Air Resources Board draft engineering evaluation which contains the Best Available Control Technology (BACT) analysis for HBRP. The HBRP facility is located approximately 42 kilometers (km) south of Redwood National Park, a Class I air quality area administered by the National Park Service (NPS). The HBRP is a major modification and will include the installation of 10 new Wartsila Model 18V50DF engine/generator sets, with a total capacity of about 163 MW. The new equipment replaces two natural gas-fired steam boilers (50 MW each) and two distillate oil peaking combustion turbines (15 MW each). The new engines are intended to operate primarily on natural gas, but have the capability of using ultra-low sulfur diesel fuel when natural gas delivery is disrupted. It is estimated that diesel fuel could be used for up to 50 hours per year of operation (down from original estimate of 800 hours per year). The HBRP replacement of the existing boilers and turbines will cause an emission reduction of approximately 573 tons per year (TPY) of nitrogen oxide (NO_x), and an increase in emissions of sulfur dioxide (SO_2) of 0.8 TPY, and 158 TPY of particulate matter less than 10 microns (PM_{10})/particulate matter less than 2.5 microns ($PM_{2.5}$).

We have the following comments concerning the Sierra Research Class I Impact Analysis and the proposed BACT analysis.

Air Quality Analysis
The Sierra Research report assessed plume impacts at Redwood National Park using VISCREEN modeling analysis and Class I increment, visibility and acid deposition impacts using CALPUFF modeling analysis.

Upon our review of the VISCREEN plume analysis performed for HBRP and its potential plume impacts to Redwood National Park we find that the analysis incorrectly subtracted the **impacts** of the existing sources that are to be retired from the **impacts** of the proposed new sources. The addition or subtraction of impacts is inappropriate for discrete plume analyses and does not allow us to properly determine potential plume impacts of the new sources emissions at Redwood National Park.

Based on new information we received on August 1, 2007, from Sierra Research and further review of computer files of the modeling analysis, we re-modeled the plume impacts of the new sources alone. We applied the emission rates (56.92 lb/hr of NOx, 4.03 lb/hr of SOx, and 42.75 lb/hr of speciated PM) for the ten new engines provided by Sierra Research. We based our modeling on the Level 2 VISCREEN file named HUMNEWG2.SUM (natural gas firing scenario) which was used by Sierra Research in their analysis. In their modeling they conducted a VISCREEN Level 2 analysis where the 1% worst-case meteorological data were applied as per the recommendations found in the EPA Workbook for Plume Visual Impact Screening and Analysis (EPA-450/4-88-015 September 1988). The 1% worst case meteorological data were determined to be "F" atmospheric stability and a wind speed of 3 meters per second. The impact under these meteorological conditions was calculated to be a Delta E (change in color) against a terrain background of 3.675 which is above the impact threshold (Delta E of 2.0). The plume contrast impact under these meteorological conditions is (-0.038) which is below the contrast impact threshold (an absolute value of 0.05). We followed additional guidance found in the EPA VISCREEN Workbook, specifically the section "ACCOUNTING FOR COMPLEX TERRAIN", where in complex terrain "the worst-case" stability class should be shifted one category to a less stable atmospheric condition. Therefore, considering the intervening terrain between the HBRP site and Redwood National Park, we ran the analysis applying "E" atmospheric stability at a wind speed of 3 meters per second. The results of this analysis indicate impacts below the VISCREEN Delta E and contrast thresholds with a Delta E of 1.986 and a contrast of 0.015. We therefore do not anticipate any perceptible plume impacts at Redwood National Park. Our VISCREEN analysis is enclosed. Please note that we only consider plume impacts **inside** the Class I area and not **outside** the Class I area. Because the North Coast Unified Air Quality Management District will limit oil firing to only 50 hours per year, we do not request that Sierra Research conduct a VISCREEN analysis for emissions from oil firing.

Considering the emission reductions associated with the units being shut down, the total amount of annual emissions of NO_x, SO_2 and $PM_{10}/PM_{2.5}$ from the new engines, and the distance to Redwood National Park, we will not ask Sierra Research to conduct a re-analysis with the EPA CALPUFF refined model. However, for future uniform haze modeling analyses, the use of the CALPUFF-Lite model, used by Sierra Research in this case, is no longer an accepted modeling method. CALPUFF-Lite is currently not listed as an approved modeling procedure in the EPA Air Quality Modeling Guidelines (40 CFR 51, Appendix W).

BACT Analysis
According to the ambient air quality impact analysis submitted by the applicant, the HBRP combined PM impacts exceed the state 24-hr and annual PM_{10} standards and the federal 24-hr $PM_{2.5}$ standard. Because of the poor local air quality and in consideration of projected impacts which would exacerbate the non-attainment problem as well as impact visibility at Redwood National Park, it seems that a more rigorous BACT analysis is warranted. The HBRP draft permit proposes to limit PM_{10} to 0.21 g/bhp-hr when burning diesel fuel. The North Coast Unified Air Quality Management District (NCUAQMD) has identified other internal combustion engines burning diesel fuel and using Diesel Particulate Filters (DPF) to reduce PM_{10} emissions to as low as 0.0116 g/bhp-hr (Kings County). Please consider that when addressing non-attainment issues and potential visibility impacts at Redwood National Park, the assertion by the applicant that DPFs "could be cost-prohibitive" is not an adequate justification to eliminate that proven technology in this case. If NCUAQMD does allow economic factors to be considered in this case, then it should require DPFs as BACT, unless HBRP demonstrates that this control technology is not feasible at Humboldt Bay.

Please note that our comments pertain to the HBRP Class I air quality impact analysis and BACT analysis. It is possible that additional emission reductions may be required at the Humboldt Bay facility in the future under the Reasonable Progress requirement of the Regional Haze Rule.

Thank you for involving us in the review of HBRP Class I impact analysis and BACT analysis. Please contact me at (303) 969-2817 if you have any questions regarding our comments concerning HBRP.

Sincerely,

Darwin W. Morse
Environmental Protection Specialist

Enclosure

cc:
Nancy Matthews
Sierra Research
1801 J Street
Sacramento, California 95814

Visual Effects Screening Analysis for
Source: HUMBOLT
Class I Area: REWO

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	4.38	G /S
NOx (as NO2)	7.17	G /S
Primary NO2	.00	G /S
Soot	1.54	G /S
Primary SO4	.25	G /S

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	230.00 km
Source-Observer Distance:	44.00 km
Min. Source-Class I Distance:	44.00 km
Max. Source-Class I Distance:	50.00 km
Plume-Source-Observer Angle:	11.25 degrees

Stability: 5
Wind Speed: 3.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	117.	50.0	51.	2.00	.304	.05	-.001
SKY	140.	117.	50.0	51.	2.00	.591	.05	-.020
TERRAIN	10.	84.	44.0	84.	2.00	1.986	.05	.015
TERRAIN	140.	84.	44.0	84.	2.00	.226	.05	.003

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	3.082*	.05	-.003
SKY	140.	0.	1.0	168.	2.00	8.621*	.05	-.230*
TERRAIN	10.	0.	1.0	168.	2.00	21.501*	.05	.245*
TERRAIN	140.	0.	1.0	168.	2.00	8.241*	.05	.177*