PERMIT TO CONSTRUCT

COMPANY NAME AND ADDRESS
Wildflower Energy LP
909 Fannin, Suite 700
Houston, Texas 77010
Contact: John Jones (Vice President) 713-374-3900
Facility ID# 127299 (new facility)
Title V Facility

EQUIPMENT LOCATION
19th Avenue (West on Indian Avenue)
0.8 miles Southwest of N. Palm Springs, CA

EQUIPMENT DESCRIPTION
Please refer to Title V permit.

PROJECT OVERVIEW
Wildflower Energy LP is proposing to install a new power plant (nominally rated at 135 MW) at a site approximately 0.8 miles southwest of North Palm Springs, within the existing Wintec wind energy farm. The plant will be called the Indigo Energy facility, and it will consist of three (simple cycle) natural gas fired gas turbines. The emissions from the gas turbines will be controlled by SCR and CO oxidation catalyst systems.

The proposed project is being developed in response to a 1999 solicitation of the California Independent System Operator (ISO) for projects to help meet a projected electric energy shortfall within the state during and after the summer of 2001. The ISO has issued Summer Reliability Agreements (SRA) to certain companies to obtain additional sources of power, and the proposed facility will be obligated to operate in accordance with the ISO's SRA. The applicant estimates that the proposed plant will operate at an annual capacity factor of 90%.

Wildflower Energy is proposing to implement the project on a fast-track basis in order to be online in time for the peak power demand season this summer. An Application for Certification was concurrently submitted to the California Energy Commission (CEC), and the project qualifies (as an emergency peaking facility) for the CEC's 21-day accelerated permit approval process. Under Executive Orders recently issued by the Governor, new peaking power plants that contract with the Department of Water Resources to provide power to California residents can apply for a 21-day expedited permit with the CEC. For the purposes of the expedited review, peaking power plants are defined as simple cycle power plants that can be constructed in a relatively small area, do not require water supplies for cooling, and can be readily connected to the existing transmission and natural gas system.

HISTORY

A permit application summary is provided below.

February 28, 2001 – Eight permit applications for two proposed power plants are submitted to the District (i.e., the proposed Senna and Indigo Energy facilities). Each application package includes applications for one LM6000 gas turbine, one APC system, one ammonia storage tank, and one Title V initial permit application.

March 8, 2001 – Applicant writes a letter to the District stating that all the equipment proposed for the Senna facility will instead be located at the proposed Indigo Energy facility. Furthermore, one additional gas turbine, APC system, and ammonia storage tank will also be located at the proposed Indigo facility.

March 14, 2001 – Applicant is informed that the four applications associated with the Senna Energy facility will be rejected since the facility will not be built.

March 14, 2001 - Applicant is informed that six additional permit applications are required for the Indigo Energy project. Permit application requirements for the proposed project are as follows: gas turbines (three applications required), APC equipment (three applications required), ammonia storage tanks (three applications required), and one application is required for the initial Title V permit.

March 19, 2001 – Applicant informs the District that only one ammonia storage tank (instead of three) will be installed at the proposed Indigo facility.

March 20, 2001 – Applicant e-mails the District a completed Form 500-F1 (Title IV – Acid Rain Phase II Facility Information Summary).

March 21, 2001 – Applicant provides permit applications for the additional two gas turbines and related APC equipment (four total).

March 22, 2001 - Application package (consisting of eight permit applications) for the Indigo Energy facility is deemed complete.

The permit application numbers corresponding to the subject equipment are provided in the table below.

Table 1 – Project Application Numbers

A/N	Submittal Date	Accept/Reject Date	Equipment
383039 (Senna facility)	2/28/01	Reject 3/27/01	Gas Turbine #1 (< 50 MW)
383040 (Senna facility)	2/28/01	Reject 3/27/01	APC System #1
383041 (Senna facility)	2/28/01	Reject 3/27/01	Ammonia Storage Tank #1
383171 (Senna facility)	2/28/01	Reject 3/27/01	Initial Title V Application
383044 (Indigo facility)	2/28/01	Accept 3/22/01	Gas Turbine #1 (< 50 MW)
383045 (Indigo facility)	2/28/01	Accept 3/22/01	APC System #1
383046 (Indigo facility)	2/28/01	Accept 3/22/01	Ammonia Storage Tank
383161 (Indigo facility)	2/28/01	Accept 3/22/01	Initial Title V Application
383808 (Indigo facility)	3/21/01	Accept 3/22/01	APC System #2
383809 (Indigo facility)	3/21/01	Accept 3/22/01	APC System #3
383810 (Indigo facility)	3/21/01	Accept 3/22/01	Gas Turbine #2 (< 50 MW)
383811 (Indigo facility)	3/21/01	Accept 3/22/01	Gas Turbine #3 (< 50 MW)

PROCESS DESCRIPTION

Gas Turbines

The applicant is proposing to install three new GE LM6000 Enhanced Sprint combustion turbine generators (CTG) with a nominal combined power output of 135 MW. The gas turbines will be fired with PUC quality natural gas only. The LM6000 has two concentric rotor shafts: the low pressure (LP) compressor and turbine form the LP rotor, and the high pressure (HP) compressor ant turbine form the HP rotor. A spray mist evaporative cooler will be used for cooling the combustion air. The CTGs will use the LP turbine to power the output shaft with a direct coupling to the 3600-rpm generator for 60 Hz power generation. The generator is a synchronous, two-pole cylindrical rotor generator with forced air-cooling. The generators will have a nominal output of 45 MW at ISO conditions. The net heat rate for each gas turbine is approximately 9,848 btu/kWh-hr (HHV).

Water will be injected into the combustors to control the NOx emissions to 25 ppmdv at 15% oxygen. The water injection system will use demineralized water injected into the combustor through ports in the fuel nozzles. Water will be supplied to the nozzles through a water manifold or premixed with fuel in a secondary manifold. Water injection begins when the turbine reaches a load of 7 MW.

TABLE 2 - Gas Turbine Data

Specification	
Manufacturer	GE
Model	LM6000 Enhanced Sprint
Fuel Type	PUC Quality Natural Gas
Average Fuel Heat Content (HHV)	1,050 btu/scf
Average Fuel Density	0.045 lbs/scf
Max Fuel Consumption (at 32° F)	22,206 lbs/hr
Max Gas Turbine Exhaust Flow (at 32° F)	1,083,600 lbs/hr
Gas Turbine Power Output	45 MW
Gas Turbine Heat Rate (HHV)	9,848 Btu/kWh-hr
Uncontrolled NOx emission	205 ppmdv
Controlled NOx Emissions (water injection)	25 ppmdv

Air Pollution Control (APC) Equipment

The APC equipment will be used to control the CO, VOC, and NOx emissions from the gas turbines. The APC equipment will also reduce the emissions of toxic air contaminants (e.g., formaldehyde and acetaldehyde) from the gas turbines. There will be one APC system for each gas turbine. Each APC system will include the following equipment: (1) aqueous ammonia storage tank, (2) ammonia/air dilution skid, (3) ammonia distribution header and injection grid supply piping, (4) specially designed ductwork, (5) CO catalyst/ammonia injection grid housing, (6) SCR catalyst housing, and (7) 105' high exhaust stack.

<u>Ammonia Transfer and Storage Equipment (one per system).</u> The ammonia will be transported to the facility in aqueous form (19% ammonia by weight) and it will be stored in one 10,000-gallon storage tank. The storage tank will be built to API-620 standards. A receiving and transfer station will be installed**,** and a vapor return line will be used during receiving operations to control filling losses.

<u>Ammonia/Air Dilution Skid (one per system).</u> The ammonia/air dilution skids will be used to vaporize the 19% aqueous ammonia so that it can be transferred to the ammonia injection grids. The ammonia/air dilution equipment will be shop assembled and skid mounted for easy field installation. Each skid will include two 15 HP dilution air fans (one operating and one spare), and two 110 kW heater elements (one operating and one spare) housed in a common heater box. In addition, instrument/atomizing air at 80-160 psig will be used to atomize the aqueous ammonia in the ammonia/air mixing chamber. The vaporized ammonia from the mixing chamber will be fed to the ammonia distribution header.

<u>Ammonia Distribution Header (one per system).</u> A carbon steel ammonia distribution header will be located alongside the reactor housing, and it will receive the hot ammonia/air mixture from the ammonia dilution skid and deliver it <u>evenly</u> to the ammonia injection grid piping. There will be one injection grid supply pipe for every six ammonia injection grid lances. Each injection grid supply pipe will be equipped with manual butterfly valving and local flow instrumentation for balancing the ammonia flow through each of the ammonia injection grid supply pipes.

<u>Ductwork.</u> Ductwork for the CO/SCR catalyst system will be based on Deltak's significant experience with the LM6000 gas turbine, and approximately 20' of ductwork will connect the gas turbine outlet to the CO catalyst housing. The ductwork will utilize their severe service design, and it has been designed to provide proper flow distribution to the catalyst. The ductwork will be provided in three shop assembled modules (i.e., Ducts A, B, and C), and it has been designed for an internal pressure of 20 inches W.C.

CO Catalyst/Ammonia Injection Grid (AIG) Housing (one per system). The oxidation catalyst will be used to control the CO and (to a lesser extent) VOC emissions from the gas turbines. The oxidation catalyst will also control the formaldehyde and acetaldehyde emissions from the gas turbines. The catalyst will be located within a structural catalyst frame integral to the housing duct (i.e., Duct D), and additional room will be provided in case another layer of catalyst is needed. The temperature of the flue gas passing through the catalyst will vary from approximately 812° Fahrenheit to 858° Fahrenheit, depending on ambient and gas turbine operating conditions. The catalyst guarantee (for performance) is as follows: (1) minimum CO conversion = 90%, (2) max CO emission rate = 5.3 lbs/hour, (3) max CO concentration = 5.1 ppmdv @ 15% O2, (4) minimum VOC conversion = 43%, (5) max VOC emission rate = 0.3 lbs/hour, (6) max VOC concentration = 0.6 ppmdv @ 15% O2, and max pressure drop across the catalyst = 1.6" W.G. The catalyst guarantee (operating life) is as follows: 3 years or 4500 hours of operation, whichever comes first, and not to exceed 42 months after the equipment is installed.

Table 3 - CO Catalyst Data Summary

Specification	
Manufacturer	Engelhard Corporation
Catalyst Type	Stainless steel monolith – platinum on alumina washcoat
Catalyst Housing Dimensions (Duct D)	11'W. X 9'L. X 51'H.
Catalyst Depth	3.2"
Catalyst Volume	85 ft^3
Space Velocity	175,000 – 141,000 hr^{-1} (depending on ambient and operating conditions)
Outlet CO	< 6 ppmdv (1-hour average) at 15% O2
Outlet VOC	< 2 ppmdv (1-hour average) at 15% O2
Minimum Operating Temp	500°F
Maximum Operating Temp	1200°F

The AIG will be located in Duct D just downstream from the CO catalyst. The purpose of this equipment is to mix the ammonia (from the ammonia/air dilution skid) with the flue gas from the gas turbines. In order to achieve the required NOx reduction (i.e., 80%), six evenly spaced (vertically) grids consisting of six evenly spaced (horizontally) ammonia injection lances will be mounted to the sidewall of the reactor housing approximately 10' upstream of the SCR catalyst.

<u>SCR Catalyst Housing (one per system).</u> The SCR catalyst will be used to control the NOx emissions from the gas turbines. The catalyst will be located within a structural catalyst frame integral to the housing duct (i.e., Duct E) downstream from the oxidation catalyst housing, and additional room will be provided in case another layer of catalyst is needed to meet present or future emission reduction requirements. Engelhard Corporation will provide the high temperature catalyst, and the temperature of the flue gas passing through the catalyst will vary from approximately 812° Fahrenheit to 858° Fahrenheit, depending on ambient and gas turbine operating conditions. The pressure drop across the catalyst will vary from 3.0 to 3.9 inches H2O, depending primarily on gas turbine operating conditions.

A tempering air system will be installed, and the purpose of this equipment is to ensure that the flue gas temperature does not exceed the upper operating range of the SCR catalyst (i.e., 871° Fahrenheit). The tempering air system will consist of a 65 HP fan that can provide 75,000 lbs/hour of ambient air at 100° F into the gas turbine exhaust stream. The air will be injected (if needed) into the ductwork in the area immediately downstream of the gas turbine exhaust expansion joint.

The catalyst guarantee (for performance) is as follows: (1) minimum NOx conversion of 80%, (2) max NOx emission rate of 8.5 lbs/hour, (3) max NOx concentration of 5 ppmdv @ 15% O2, and (4) max ammonia slip of 5 ppmdv @ 15% O2. The catalyst guarantee (operating life) is as follows: 3 years or 4,500 hours of operation, whichever occurs first, and not to exceed42 months after the equipment is installed. The warranty specifies that the maximum temperature of the exhaust gas into the catalyst shall not exceed 871° Fahrenheit, and a tempering air system will be installed to ensure that the exhaust gas temperature does not exceed the above temperature.

Table 4 - SCR Data Summary

Specification	
Catalyst Manufacturer	Engelhard Corporation
Catalyst Type	NOx-CAT™ VNX-HT vanadia-titania catalyst
SCR Housing Dimensions (Duct E)	11’W. X 9’L. X 51’H.
Catalyst Depth	14”
Catalyst Volume	790 ft^3
Space Velocity	18,900 – 15,200 hr^{-1} (depending on ambient and operating conditions)
Area Velocity	~ 0.01 ft/sec
Ammonia Injection Rate	110 lbs/hr max
Max Ammonia Slip	5 ppm 1-hour average at 15% O2
Outlet NOx	5 ppm 1-hour average at 15% O2

Process Controls. A PLC based automatic control system will be used to control the tempering air fan, the dilution air fans, the dilution air heaters, and the ammonia flow controller. Precise ammonia flow control is needed in order to ensure compliance with the stringent NOx and ammonia slip emissions limits. The ammonia flow controller will control the ammonia injection rate into the SCR based on the gas turbine load signal and the NOx reading from the CEMS. The ammonia flow controller's setpoint will be adjusted based on the NOx reading in the stack.

The purchased equipment cost for each APC system will be approximately $2,000,000.

EMISSIONS:

Emissions data for the gas turbines is provided for the following modes of operation:

1. Normal Operations
2. Startups and Shutdowns
3. Commissioning Period

Normal Operations
The applicant provided stack and emissions data for the following five full load normal operating conditions. During normal operations, the air pollutants below are assumed to be controlled to BACT levels. Stack parameter information for each operating scenario is included in Appendix A.

Operating Scenario 100: Ambient Temp = 32° F, Ambient Air Injection Off, Spray Mist Combustion Air Cooling Off, and Stack Gas Flowrate = 502,588 acfm
Operating Scenario 101: Ambient Temp = 70° F, Ambient Air Injection Off, Spray Mist Combustion Air Cooling Off, and Stack Gas Flowrate = 467,568 acfm
Operating Scenario 102: Ambient Temp = 70° F, Ambient Air Injection Off, Spray Mist Combustion Air Cooling On, and Stack Gas Flowrate = 472,681 acfm
Operating Scenario 103: Ambient Temp = 112° F, Ambient Air Injection On, Spray Mist Combustion Air Cooling Off and Stack Gas Flowrate = 428,988 acfm
Operating Scenario 104: Ambient Temp = 112° F, Ambient Air Injection Off, Spray Mist Combustion Air Cooling On, and Stack Gas Flowrate = 457,010 acfm

The highest hourly CO emission rate will occur during Operating Scenario 100.
The highest hourly NOx emission rate will occur during Operating Scenario 100.
The highest hourly PM10 emission rate will be the same for all five operating scenarios.
The highest hourly VOC emission rate will occur during Operating Scenario 100.
The highest hourly SOx emission rate will be the same for all five operating scenarios.
The highest hourly NH_3 emissions occur during Operating Scenario 100

Emission Rates - Normal Operation

Data:

1. Max fuel flow rate = 22,206 lbs/hr (occurs during operating condition 100)
2. Average natural gas density = 0.045 lbs/scf
3. Emission Factor (lbs/MMscf) = (uncontrolled or controlled ppmdv) *(MW)*(1/SMV)*(20.9/5.9)*(Fd)*(FHC)
   where,
   uncontrolled ppmdv = concentration at catalyst inlet corrected to 15% O2
   controlled ppmdv = BACT required corrected to 15% O2
   MW = molecular weight (lbs/lb-mole)
   SMV = specific molar volume at 68° Fahrenheit
   Fd = dry oxygen F-Factor for natural gas = 8,710 dscf/MMbtu at 68° F
   FHC = fuel heat content (natural gas) = 1,050 btu/dscf

Detailed emissions calculations are included in Appendix B. The table below provides a summary of the emissions.

Table 5 – Mass Emission Rates (per gas turbine) - Normal Operation

Pollutant	Maximum Uncontrolled		Maximum Controlled		Average Yearly Controlled
	lbs/hr	lbs/day	lbs/hr	lbs/day	lbs/year
CO	59.3	1,423	7.0	168	43,926
NOx	47.7	1,145	9.5	228	60,094
PM10	3.3	79	3.3	79	20,890
VOC	1.1	26	0.3	7	1,002
SOx	0.71	17	0.71	17	4,435
NH3	0	0	3.5	84	22,034

Max daily emissions based on 24 hours/day.
Average yearly controlled emissions based on 7,154 hours/year, and the average of the emission rates calculated for operating scenarios 100-104.

Startups and Shutdowns

Startups begin with the turbine's initial firing and continue until the unit meets the emission concentration limits. The duration of a startup will be approximately 16 minutes. The NOx, CO, and VOC emissions will be uncontrolled for the first ten minutes, and the NOx emissions will be partially controlled to 25 ppm for the next 6 minutes. After 10 minutes, the CO and VOC emissions will be controlled to at or below BACT levels, and after 16 minutes, the NOx emissions will be controlled to at or below BACT levels.

Shutdowns begin with the initiation of the turbine shutdown sequence and end with cessation of turbine firing. A shutdown will last approximately 9-10 minutes from full load operation to zero emissions. Turbine shutdowns will start with a hot catalyst and will be executed in a manner that will not result in operations with catalyst temperatures below the SCR threshold value for an appreciable length of time. Shutdown emissions will be assumed to be equal to emissions during normal operation.

Emission Rates – Startups and Shutdowns

Data:

1. Number of startups per day = variable (on average 1)
2. Number of startups per year = 365
3. Startup duration: CO and VOC = 10 minutes, NOx = 16 minutes
4. Number of shutdowns per day = variable (on average 1)
5. Number of shutdowns per year = 365
6. Shutdown duration = approximately 10 minutes

Calculations:

1. Maximum Hourly Startup Emissions:

CO = 3 lbs/10 min + 5.83 lbs/50 min = 8.83 lbs/hr
NOx = 3 lbs/10 min + 4.77 lbs/6 min + 6.97 lbs/44 min = 14.74 lbs/hr
PM10 = less than during normal operation (assume equal) = 3.3 lbs/hr
VOC = 0.1 lbs/10 minutes + 0.25 lbs/50 minutes = 0.35 lbs/hr
SOx = less than during normal operation (assume equal) = 0.71 lbs/hr
NH3 = 0 lbs/16 min + 2.6 lbs/44 min = 2.6 lbs/hr

2. Average Annual Startup Emissions:
CO = (3 lbs/10 min + 5.08 lbs/50 min) * 365 startups/yr = 2,950 lbs/yr
NOx = (3 lbs/10 min + 4.2 lbs/6 min + 6.16 lbs/44 min) * 365 startups/yr = 4,876 lbs/yr
PM10 = 2.9 lbs/hr * 365 startups/yr = 1,059 lbs/yr
VOC = (0.1 lbs/10 min + 0.12 lbs/50 min) * 365 startups/yr = 80 lbs/yr
SOx = 0.62 lbs/hr * 365 startups/yr = 226 lbs/yr
NH3 = (0 lbs/16 min + 2.3 lbs/44 min) * 365 startups/yr = 840 lbs/yr

3. Maximum Hourly Shutdown Emissions (assume equal to normal operation):
CO = 7.0 lbs/hr
NOx = 9.5 lbs/hr
PM10 = 3.3 lbs/hr
VOC = 0.3 lbs/hr
SOx = 0.71 lbs/hr
NH3 = 3.5 lbs/hr

4. Average Annual Shutdown Emissions:
CO = 6.1 lbs/hr * 365 startups/yr = 2,227 lbs/yr
NOx = 8.4 lbs/hr * 365 startups/yr = 3,066 lbs/yr
PM10 = 2.9 lbs/hr * 365 startups/yr = 1,059 lbs/yr
VOC = 0.14 lb/hr * 365 startups/yr = 51 lbs/yr
SOx = 0.62 lb/hr * 365 startups/yr = 226 lbs/yr
NH3 = 3.1 lbs/hr * 365 startups/yr = 1,131 lbs/yr

Table 6 – Mass Emission Rates (per turbine) – Startups and Shutdowns

Pollutant	Startup Max Hourly Emission Rate (lbs/hour)	Startup Average Annual Emissions (lbs/year)	Shutdown Max Hourly Emission Rate (lbs/hour)	Shutdown Average Annual Emissions (lbs/year)
CO	8.83	2,950	7.0	2,227
NOx	14.74	4,876	9.5	3,066
PM10	3.3	1,059	3.3	1,059
VOC	0.35	80	0.3	51
SOx	0.71	226	0.71	226
NH3	2.6	840	3.5	1,131

Average annual startup emissions based on 365 startups per year, and the average of the emission rates calculated for operating scenarios 100-104.

Average annual shutdown emissions based on 365 shutdowns per year, and the average of the emission rates calculated for operating scenarios 100-104.

Note, the PM10 and SOx emissions are not significantly reduced by operation of the CO catalyst or the SCR, and emissions of these pollutants are less during partial load periods than during normal full load operation.

Commissioning Period

Commissioning will be performed on one turbine at a time, and the commissioning time is expected to last 84 hours per turbine (based on experience with a similar project). During commissioning, emissions of NOx, CO, and VOC are expected to be higher than during normal operation because the water injection, SCR, and CO control systems may not be fully operational, and the turbine combustor may not be optimally tuned.

The emissions during the projected 84-hour commissioning schedule (based on experience with similar equipment) will be based on the following assumptions: uncontrolled for first 10 hours, water injection for 11 through 60 hours, and complete control for hours 61-84. Based on the above, the emissions will be as follows:

Emissions For Hours 0-10 Per Turbine (assume full load and operating scenario 104)
CO = 3 lbs/10 minutes * 600 minutes = 180 lbs
NOx = 3 lbs/10 minutes * 600 minutes = 180 lbs
PM10 = 2.8 lbs/hour * 10 hours = 28 lbs
VOC = 0.1 lbs/10 minutes * 600 minutes = 6 lbs
SOx = 0.60 lbs/hour * 10 hours = 6 lbs
NH3 = 0 lbs

Emissions For Hours 11-60 Per Turbine (assume full load and operating scenario 104)
CO = 3 lbs/10 minutes * 3,000 minutes = 900 lbs
NOx = 40.9 lbs/hour * 50 hours = 2,045 lbs
PM10 = 2.8 lbs/hour * 50 hours = 140 lbs
VOC = 0.1 lbs/10 minutes * 3,000 minutes = 30 lbs
SOx = 0.60 lbs/hour * 50 hours = 30 lbs
NH3 = 0 lbs

Emissions For Hours 61-84 Per Turbine (assume full load and operating scenario 104)
CO = 6 lbs/hour * 24 hours = 144 lbs
NOx = 8.2 lbs/hour * 24 hours = 197 lbs
PM10 = 2.8 lbs/hour * 24 hours = 67 lbs
VOC = 0.1 lbs/hour * 24 hours = 2.4 lbs
SOx = 0.60 lbs/hour * 24 hours = 14.4 lbs
NH3 = 3.0 lbs/hour * 24 hours = 72 lbs

Table 7 – Mass Emissions – Commissioning Period

Pollutant	Emissions Per Turbine (lbs)	Combined Emissions For All Three Turbines (lbs)
CO	1,224	3,672
NOx	2,422	7,266
PM10	235	705
VOC	38	114
SOx	50	150
NH3	72	216

<u>Emission Offsets Calculations</u>

Data:
1. Gas Turbine fuel flow at 100% load = 0.4935 MMscf/hr per turbine (based on winter operating condition 100).
2. Gas Turbine fuel flow at 100% load = 0.4226 MMscf/hr per turbine (based on summer operating condition 104).
3. Maximum monthly hours of operation = 670 hours per turbine (based on 90% capacity factor).

Assumptions:
1. emissions during shutdown = emissions during normal operation
2. PM10 and SOx emissions during startup = emissions during normal operation
3. commissioning period lasts 84 hours
4. emissions from each identical turbine are the same

Calculations: Detailed emission offsets calculations are included in Appendix C

Table 8 – 30-day Average Emissions and Offsets Requirements

Pollutant	30-day Average Emissions Per Turbine (lbs/day)	30-day Average Emissions Total (3 turbines) (lbs/day)	Total Emission Offsets Required (lbs/day)
CO	160	480	N/A
NOx	246	738	885
PM10	73.7	221	265
VOC	6.7	20	0 (< 4 tons/yr)
SOx	16	48	57
NH3	77	231	N/A

EVALUATION

RULE 212 – Standards for Approving Permits
The applicant will be required to distribute a public notice (in accordance with the requirements specified in this rule) because the daily maximum NOx, PM10, and CO emissions will exceed the emissions thresholds specified in subdivision (g) of this rule. The required public notice comment period is 30 days.

Rule 218 – Continuous Emission Monitoring
The applicant will need to submit a CEMS application to the District prior to installing the CEMS. The NOx and CO CEMS will need to be certified in accordance with the requirements specified in this rule.

RULE 401 – Visible Emissions
Visible emissions are not expected under normal operating conditions of the turbines.

RULE 402 – Nuisance
Nuisance problems are not expected under normal operating conditions of the turbines.

RULE 403 – Fugitive Dust
This rule prohibits emissions of fugitive dust beyond the property line of the emission source. During normal operations, compliance with this rule is expected. However during the construction phase of the project, reasonably available control measures will be used to ensure compliance with this rule.

RULE 407 – Liquid and Gaseous Air Contaminants

This rule limits the CO emissions to 2000 ppm max, and the sulfur content of the exhaust to 500 ppm for equipment not subject to the emission concentration limits of 431.1. Since the gas turbines are subject to the limits of Rule 431.1, only the 2000 ppm limit of this rule applies. It is expected that the equipment will be able to meet the CO limit with the use of an oxidation catalyst. Compliance will be verified through CEMS data.

RULE 409 – Combustion Contaminants

The rule limits PM emissions to 0.1 grains/scf. Based on experience with similar equipment, compliance with this rule is expected. The calculated PM concentration is provided below.

Exhaust gas Flowrate = 188,032 scfmd = 11,281,920 scfhd
Maximum PM emissions = 3.3 lbs/hr

Grain loading = (3.3 lbs/hr) * (7000 grains/lb)

11,281,920 scfhd

= 0.002 grains/scfd

Compliance will be verified through the initial performance test.

RULE 431.1 – Sulfur Content of Natural Gas

This rule requires that the natural gas supplied to the turbines meet a sulfur content limit of 16 ppmv calculated as hydrogen sulfide. The PUC quality natural gas that will be supplied to the gas turbines will meet this requirement.

RULE 474 – Fuel Burning Equipment – Oxides of Nitrogen

The maximum gross heat input for each gas turbine will be less than 555 MMbtu/hour. Therefore, this rule is not applicable.

RULE 475 –Electric Power Generating Equipment

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. Requirements are that the equipment meet a limit for combustion contaminants (combustion contaminants are defined as particulate matter in AQMD Regulation I) of 11 lbs/hr, or 0.01 grains/scf. Compliance is achieved if either the mass limit or the concentration limit is met. The maximum PM10 emission rate from the subject gas turbines will be 3.3 lbs/hr. Therefore, compliance with this rule is expected. Compliance will be verified through the initial performance test.

RULE 476 –Steam Generating Equipment
The gas turbines will not be used in conjunction with steam producing equipment. Therefore, this rule is not applicable.

RULE 1134 –Emissions of NOx from Stationary Gas Turbines
This rule applies to stationary gas turbines installed prior to August 4, 1989. Therefore, this rule is not applicable to this project.

REGULATION XIII – New Source Review (Non-RECLAIM facility)
The proposed facility will be located in the Riverside County portion of the SSAB, and it will be classified as a Major Polluting Facility because the NOx emissions will be greater than 25 tons/year. The Riverside County portion of the SSAB is in attainment with both federal and state standards for CO. Therefore, this regulation is not applicable to the CO emissions from the proposed equipment. The proposed facility is required to comply with the following BACT, modeling, offsets, and protection of visibility requirements specified in this regulation.

1303(a) - BACT
The BACT requirements for the gas turbines will be based on the ARB's guidance document for power plants entitled Guidance for Power Plant Citing and Best Available Control Technology, dated September 1999. A summary of the BACT requirements is provided in the following table.

Table 9 – BACT Requirements

NOx	CO	VOC	PM10	SOx
5 ppmdv @ 15% O2, 1 hour rolling average	6 ppmdv @ 15% O2, 3 hour rolling average	2 ppmdv @ 15% O2, 1 hour rolling average OR 0.0027 lbs/MMbtu, HHV	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf

The applicant is proposing the following BACT levels for this project. Note that these levels generally represent guaranteed emissions under baseload operating conditions.

Table 10 – Proposed BACT

NOx	CO	VOC	PM10/SOx	NH3
5 ppmdv @ 15% O2, 1-hour rolling average	6 ppmdv @ 15% O2, 1-hour rolling average	2 ppmdv @ 15% O2, 1-hour rolling average	Exclusive use of PUC quality natural gas with a max sulfur content of 1 grain per 100 cubic feet	5 ppmdv @ 15% O2, 1-hour rolling average

The proposed control levels meet BACT requirements for all criteria pollutants.

In addition, the BACT requirement for ammonia slip is 5 ppmdv corrected to 15% oxygen.

A NOx CEMS will be used to verify compliance with the NOx BACT limit, and the CO CEMS will be used to verify compliance with the PSD BACT requirement in Rule 1703.

<u>1303(b)(1) - Modeling</u>
Modeling is required for the NOx and PM10 emissions per Rule 1303(b). This rule requires the applicant to substantiate with modeling that the project will not cause a significant increase in an air quality concentration. The applicant determined the maximum project impacts using the ISCST3 model. Maximum NOx impacts occur during the simultaneous startup of the three gas turbines during a low ambient temperature condition (i.e., 32° Fahrenheit). Table 11 below shows the applicable standards for the subject pollutants, and the results from modeling analysis.

Table 11 - New Source Review Modeling

Pollutant	Averaging Time	Significant Change in Air Quality Concentration	Model Results
NOx	1-hour	20 ug/m^3	19.99 ug/m^3
	Annual	1 ug/m^3	0.160 ug/m^3
PM10	24-hour	2.5 ug/m^3	0.865 ug/m^3
	Annual Geometric Mean	1 ug/m^3	0.0615 ug/m^3

The applicant's modeling analysis was reviewed by AQMD modeling staff, and the following deficiency regarding the modeling analysis required by Rule 1303(b)(1) was noted in a memo from Henry Hogo to Pang Mueller dated March 22, 2001. The deficiency regards the receptor spacing in the area adjacent to the area of peak impact. The peak impact could be higher than the reported value of 20.07 ug/m3 because the impact occurred within an area with a 500-meter receptor spacing. The applicant performed additional modeling using a lower NOx emission rate and a 100-meter receptor spacing for the area adjacent to the peak impact area in order to determine/verify the peak NOx impact. Using a max hourly NOx emissions rate of 40.311 lbs/hour (for all three turbines in startup) the applicant was able to demonstrate compliance with this rule (i.e., the modeled peak impact of 19.99 ug/m3 is below 20 ug/m3 significance level).

<u>1303(b)(2) - Emission Offsets</u>

Emission offsets will be needed for the NOx, SOx, and PM10 emissions from the proposed facility. The amount of offsets needed is based on the calculation methodology specified in Rule 1306(b). Detailed emission offsets calculations are included in Appendix C. A summary of emission offsets requirements is included in the table below.

Table 12 – Emission Offsets

Pollutant	Offset Ratio	Emission Offsets Required (lbs/day)	Source of Offsets
NOx	1.2	885	State Funded ERC Bank, or purchased ERCs
PM10	1.2	265	State Funded ERC Bank, or purchased ERCs, or AQMD's Priority Reserve
SOx	1.2	57	Purchased ERCs

If ERCs are received from the State funded bank, then the bank disburser will issue a letter of transaction. The letter of transaction will include the following information: date of transaction, proponent name/phone number, facility name, facility location, quantity of ERCs requested, District offset ratio applied, total quantity of ERCs issued, total monies received, expected date of online generation, size (MW) of the proposed facility, and ERC expiration date. Such letter of transaction shall also require that the qualified applicant notify the District in writing, identifying the permanent offsets to be used in lieu of the issued ERCs, six months before expiration. Such letter of transaction shall also require that the qualified applicant submit to the District contracts or other evidence of acquisition of the permanent offsets no less than 90 days before expiration.

1303(b)(3) – Sensitive Zone Requirements
For this project, ERCs can be purchased from either Zone 1 or Zone 2A.

1303(b)(4) – Facility Compliance
The new facility will comply with all applicable rules and regulations of the District.

1303(b)(5)(a) – Alternative Analysis
Compliance with CEQA will be determined by the CEC.

1303(b)(5)(b) – Statewide Compliance
N/A

1303(b)(5)(c) – Protection of Visibility
The proposed facility will be located near the following Federal Class I areas: San Jacinto (7 km), Joshua Tree (11 km), San Gorgonio (24 km), Aqua Tibia (62 km), and Cucamonga (103 km). The potential PM10 and NOx emissions from the proposed facility will exceed 15 tons/year and 40 tons/year, respectively. Based on the above, a modeling analysis for plume visibility is required for this project. The applicant submitted a modeling analysis in accordance with the procedures specified in Appendix B (of this regulation).

The applicant used the EPA's VISCREEN model to perform the level 1 screening analyses. This level of analysis entails use of worst-case default input assumptions (e.g., extremely stable atmospheric turbulence conditions, and very low wind speed persisting for 12 consecutive hours in a direction towards the closest Class I boundary) to determine adverse plume impacts on visibility. Level 1 analyses were performed for the five closest Class I areas, and only the results for the Cucamonga area (which is 103 km from the proposed site) showed plume impacts below all the screening criteria specified in Appendix B.

The applicant performed level 2 screening analyses (for the four Class I area that failed the level 1 analyses) that used more site specific input data than what was used for the extremely conservative level 1 analyses. The level 2 procedure consists of analyzing the available meteorological data to incorporate information on the frequency of conditions that may lead to adverse plume impacts on the Class I area. Meteorological data from Palm Springs was first analyzed to determine the frequency of various combinations of wind speed and stability in 22.5 degree wind direction sectors that would carry the plume from the proposed facility toward each of the Class I areas. The results of the level 2 analyses show that the cumulative frequencies of all meteorological events that would transport the plume from the proposed facility to either the Aqua Tibia or San Jacinto Wilderness areas were less than one percent. Thus, no further modeling is required and significant visibility impacts due to the proposed project are not predicted to occur in either of the above Class I areas.

The applicant performed additional level 2 screening analyses for the remaining two Class I areas using the meteorological input conditions that caused the cumulative frequency to reach one percent. The VISCREEN model was rerun using the above meteorological conditions to determine whether the impacts above the model's screening criteria would be predicted. For these simulations, the average measured background visible range value for the project was obtained from the U.S. Forest Service website. For the San Gorgonio area, the plume parameters predicted by VISCREEN were below all the screening criteria for inside and out side the Class I area.

A revised level 2 screening analysis for the Joshua Tree Class I area was submitted to the District on March 27, 2001. The revised level 2 screening analysis contained new (more site specific) meteorological data obtained from the District, and the background ozone level was modified from 0.04 ppm to 0.065 ppm based on the applicant's discussions with the National Park Service. The applicant also included a 1.5 lbs/hr sulfate input based on discussions with the District regarding the conversion of SO2 to SO3 in the CO catalyst. The revised level 2 VISCREEN analysis indicates that the plume impacts for the project will not exceed the delta E and contrast parameters either inside or outside this Class I area.

Based on the above, the proposed project's impacts to the five nearest Class I areas are expected to be less than significant.

RULE 1401 – Carcinogenic Air Contaminants
The applicant performed a Tier 4 modeling analysis using the ISCST3 model to determine maximum cancer, chronic, and acute risks from the project. The potential health risks were assessed using the procedures consistent with the CAPCOA Risk Assessment Guidelines (CAPCOA, 1993) and AQMD Rule 1401. The results of the modeling analyses indicate that compliance with this rule will be achieved. The applicant's modeling information was reviewed by AQMD modeling staff, and their analyses were deemed acceptable on March 22, 2001. A summary of the modeling results is included in the table below.

Table 13 – Results of Health Risk Assessment

PARAMETER	MICR	Acute Hazard Index	Chronic Hazard Index
Significance Value	1	1	1
Worst Case Risk Value	0.1314	0.0334	0.000665
Operating Scenario	103	103	103
Distance to Max Impact Receptor (km)	10.6	10.6	4.9
Direction from Stack to Max Risk Value	Southeast	Southeast	Northwest

<u>REGULATION XVII – Prevention of Significant Deterioration</u>
The Riverside County portion of the Salton Sea Air Basin where the project is to be located is an attainment area for the following pollutants: NO2, SO2, and CO. Rule 1702 defines a significant increase for the above pollutants as follows: NO2 > 40 tons/yr, SO2 > 40 tons/yr, and CO > 100 tons/yr. The NOx emissions from the facility will be greater than 40 tons/year; therefore, a PSD review is required for this air pollutant.

<u>1703(a)(3)(A) – Facility Compliance</u>
The applicant has certified in writing that the subject facility will comply with all applicable federal, state, and AQMD rules and regulations.

<u>1703(a)(3)(B) - BACT</u>
The NOx emissions from the gas turbines will be controlled by SCR equipment to current BACT levels (i.e., 5 ppmdv corrected to 15% oxygen). Therefore, compliance with this rule is expected.

<u>1703(a)(3)(C) – Air Quality Modeling</u>
The applicant used the ISCST3 model to determine if the NO2 emissions from the project would create a violation of the National or State Ambient Air Quality Standards (AAQS), or the allowable PSD increments. The results of their modeling analyses (which were deemed acceptable by our Planning Dept.) are as follows:

<u>1-hour NO2 Averaging Period</u>
Predicted Max 1-hour Impact (from the facility) = 19.99 ug/m3
Background Level (Palm Springs Fire Station, AQMD Station, 1999) = 131.6 ug/m3
Predicted Total Concentration = 151.6 ug/m3
AAQS = 470 ug/m3

<u>Annual NO2 Averaging Period</u>
Predicted Max Annual Impact = 0.160 ug/m3
Background Level (Palm Springs Fire Station, AQMD Station, 1999) = 36.79 ug/m3
Predicted Total Concentration = 36.95 ug/m3
AAQS = 100 ug/m3

<u>NO2 PSD Increment</u>
Predicted Max Annual Impact = 0.160 ug/m3
Impact Area = 0 (the emissions never reach 1 ug/m3 (annual average))
Max Allowable Increase (Class I Areas) = 2.5 ug/m3 (annual arithmetic mean)
Max Allowable Increase (Class II Areas) = 25 ug/m3 (annual arithmetic mean)

The predicted total concentrations will be below the above AAQS standards, and the predicted NOx PSD increment will not exceed the maximum allowable levels specified in this rule. Therefore, compliance with this rule is expected.

<u>1703(a)(3)(D) – Pre-Construction Ambient Air Quality Monitoring</u>
The applicant used existing continuous monitoring data collected by the District at the Palm Springs Monitoring Station to determine the pre-construction ambient air quality. Pre-construction monitoring will not be required because the predicted annual NOx impacts are below the 14 ug/m3 exemption level.

<u>1703(a)(3)(E) – Soil and Vegetation Impacts</u>
Maximum modeled NO2 and SO2 impacts from normal facility operations were compared to U.S. Forest Service (USFS) significant impact thresholds for soil and vegetation ecosystems for Class I wilderness areas. The table below compares the maximum modeled NO2 and SO2 impacts with the USFS significance levels. All predicted impacts are below the USFS significance levels.

Table 14 – Soil and Vegetation Impacts

Pollutant	USFS Significance Level	Maximum Project Impact
SO2 Annual Conc.	8 ppbv	0.012 ppbv
SO2 Hourly Conc.	40 ppbv	0.90 ppbv
NO2 Annual Conc.	15 ppbv	0.081 ppbv
Total Sulfur Deposition	5 kg/ha-yr	0.096 kg/ha-yr
Total Nitrogen Deposition	3 kg/ha-yr	0.307 kg/ha-yr

1703(a)(3)(E) – Visibility Impacts
The applicant followed the procedures specified in the U.S. EPA document entitled "Workbook for Plume Visual Impact Screening and Analysis, 1992" in performing their visibility analysis. They performed Level 1 and II visibility analyses for the nearest Class I areas (i.e., Cucamonga, San Jacinto, San Gorgonio, Aqua Tibia, and Joshua Tree National Park), and the predicted total color contrast values (Delta-E) and plume contrast values for the above Class I areas (with the exception of Joshua Tree) were below the threshold values of 2 and 0.5, respectively. The applicant consulted with AQMD and National Park Service modeling staff then reran the VISCREEN model using more detailed/site specific information and the results of their analysis indicate that adverse plume visibility impacts will not occur either inside or outside the Joshua Tree Class I area. Details regarding the their visibility analyses are included in the master file.

1703(a)(3)(F) – Application Distribution
The District provided a copy of the application package and the modeling CD to the following people on March 22, 2001: Mike McCorison (State Land Manager), Jody Cook (Forest Supervisor), Chris Holbeck (National Park Service), John Notar (Federal Land Manager), Gene Simmerman (Forest Supervisor), Anne Fege (US Forest Service), and Gerardo Rios (U.S. EPA Region IX).

Regulation XXX – Title V
The maximum NOx emissions from the proposed facility will exceed the 25 tons/year threshold for this air pollutant. Therefore, a Title V permit must be obtained prior to construction. The applicant submitted the required forms, and the District deemed the application package complete on March 22, 2001. The application package has been evaluated and it has been determined that the proposed facility will comply with all applicable federal, state, and AQMD rules. The applicant was provided a copy of the draft permit on March 28, 2001, and the public notice of Intent to Issue Permit was published on March 28, 2001.

California Environmental Quality Act (CEQA)
Per the Governor's Executive Order, this emergency peaking plant is exempt from CEQA.

<u>40CFR Part 60 Subpart GG – NSPS for Gas Turbines</u>
NSPS applies to the subject turbines since the heat input is greater that 10.7 gigajoules per hour at peak load. The manufacturer's rated heat rate at manufacturer's rated load (kj/W-hr) based on the fuel LHV = 9.43 kj/W-hr. The allowable NOx emissions for each turbine is based on the formula below.

NOx standard (ppmdv @ 15% O2 = 0.0075*14.4*(1/Y) + F, where
Y = above heat rate = 9.43 kj/W-hr
F = 0 for natural gas with a nitrogen content < 0.015% (by wt.)
NOx = 115 ppmdv corrected to 15% O2

The allowable SOx emissions = 150ppm.

A performance test is required within 60 days of installation, and compliance with this rule is expected.

<u>40CFR Part 63 – NESHAPS</u>
EPA is in the process of establishing a NESHAP for gas turbines, and a rule is scheduled for promulgation in 2002. Until the NESHAP is promulgated, turbine MACT standards must be evaluated on a case-by-case basis. For this project, the HAP emissions from the subject turbines will be below the major source thresholds of 10 tpy for a single HAP or 25 tpy for a combination of HAPs. Based on the above, the subject turbines are not considered major source of HAPs, and are exempt from this regulation.

<u>40CFR Part 64 - Compliance Assurance Monitoring</u>
The NOx and CO CEMS will be certified and operated in accordance with AQMD Rule 218. Therefore, compliance with the CAM regulation is expected.

<u>40CFR Part 72 – Acid Rain Program</u>
Acid rain requirements will be included in the Title V permit.

<u>DISCUSSION</u>
Based on the evaluation contained herein, it has been determined that the subject equipment will comply with all applicable federal, state, and AQMD rules and regulations.

<u>CONDITIONS</u>
Please refer to the Title V permit.