Attachment L
SCAQMD Permit Application

APPLICANT

CENCO Electric Company
P.O. Box 2108
12345 Lakeland Road
Santa Fe Springs, CA 90670

EQUIPMENT DESCRIPTION

Process 1: INTERNAL COMBUSTION – TURBINES – POWER GENERATION
TURBINE, GAS, NO. 1, COMBINED CYCLE, NATURAL GAS (DIESEL BACKUP), PRATT & WHITNEY FT8, WITH WATER INJECTION, 282 MMBTU/HR (HHV) TURBINE, GAS, NO. 2, COMBINED CYCLE, NATURAL GAS (DIESEL BACKUP), PRATT & WHITNEY FT8, WITH WATER INJECTION, 282 MMBTU/HR (HHV) CO OXIDATION CATALYST, PEERLESS SELECTIVE CATALYTIC REDUCTION, PEERLESS AMMONIA INJECTION GRID STACK, TURBINES 1 AND 2 GENERATOR, 51.5 MW GENERATOR, HEAT RECOVERY STEAM
Process 2: AMMONIA STORAGE
STORAGE TANK NO.1, AQUEOUS AMMONIA, 19% SOLUTION, 12,000 GALLONS, WITH A VAPOR RETURN LINE

EQUIPMENT LOCATION

12345 Lakeland Road
Santa Fe Springs, CA

Facility Ownership
The project will be located on property owned by CENCO Refining Company (“CENCO”) and operated by CENCO Electric Company (“CEC”).

BACKGROUND

CEC plans to install one Pratt & Whitney Twin Pac system, consisting of two FT8 gas turbines connected to a single electric generator. The turbines will initially operate as simple cycle, generating 51.5 MW according to a contract with the California Department of Water Resources.

When the equipment becomes available, CEC will begin installation of a heat recovery steam generator (HRSG) and a steam turbine for increased efficiency, a selective catalytic reduction (SCR) system for NOx control, and an oxidation catalyst for CO control.

<u>Existing Site</u>

The plant will be located in the existing CENCO Refining Company facility in Santa Fe Springs. The applicant requests a separate AQMD facility identification number for the project.

CEC submitted an application to the California Energy Commission on June 25, 2001 to be considered for 21-day expedited permit processing for emergency peaking plants.

PROCESS DESCRIPTION

The Pratt & Whitney Twin Pac generator unit will initially operate as simple cycle. Water injection will limit NOx emissions to 25 ppm. Additional power equipment will be installed in the second phase of the project, converting the system to a combined cycle. The combination of water injection and SCR will reduce NOx emissions to 2.5 ppm. An oxidation catalyst will reduce CO emissions 75%, from 25 ppm to approximately 6 ppm, and result in some SOx and VOC reductions as well.

Each of the two FT8 turbines in the Twin Pac has a gross output of 27,500 kW at standard conditions, corresponding to a maximum heat input rate of approximately 256 MMBtu/hr. The primary fuel will be PUC quality natural gas supplied by the Southern California Gas Company. In the event of gas curtailment, the plant will run on jet fuel or diesel fuel which will be stored at the refinery.

Continuous emission monitors will measure NOx, CO, and O_2 in the turbine exhaust. Other instruments will measure and record fuel use, water injection rate, ammonia injection rate, exhaust temperature prior to the SCR, turbine output, and pressure drop across the SCR catalyst. Ammonia slip will be determined either through comparison of NOx concentrations before and after the SCR, or directly, by an ammonia slip monitor.

Gas Turbine Data

Manufacturer	Pratt & Whitney
Model	FT8
Primary Fuel	Natural gas, 1018 Btu/scf
Back-up Fuel	CARB diesel, 128000 Btu/gal
Fuel Consumption	0.28 MMscf/hr / 2200 gal/hr
Exhaust Flow	195 lb/sec
Gas Turbine Heat Input	282 MMBtu/hr (HHV)
Gas Turbine Output, ISO	27.7 MW
Net Plant Heat Rate, LHV	9190 Btu/kW-hr
Net Plant Heat Rate, HHV	10300 Btu/kW-hr

Control Systems

An SCR and oxidation catalyst will be installed to control NOx, CO, and VOC emissions. The control equipment is not likely to be fabricated in time for the start-up of the turbines. Consequently, initial emissions will be controlled by a water injection system.

The water injection rate varies with turbine load and ambient conditions, with the maximum injection rate being about 25 gallons per minute to each turbine. An on-site demineralization system will treat domestic water supplied by the city or recycled water from the Central Basin Water District prior to injection.

In the second phase of the project, commencing no later than June 1, 2002, an SCR system and a CO catalyst will be installed. The SCR manufacturer guarantees 90% reduction to 2.5 ppm NOx for three years or 26,280 hours.

SCR Data

Manufacturer	Peerless Manufacturing Co.
Ammonia Injection Rate	185 lb/hr capacity
Ammonia Slip	5 ppm 1-hour average at 15% O_2
Outlet NOx	2.5 ppm 1-hour avg at 15% O_2
Minimum Operating Temp	550 F

CO catalyst

The CO catalyst manufacturer guarantees 75% reduction to 6 ppm CO for 3 years or 26,280 hours. Typical SO_2 oxidation rates for CO catalysts are about 50-60%. Some reduction in VOC emissions can be expected as well.

CO Catalyst Data

Manufacturer	Peerless Manufacturing Co.
Outlet CO	6 ppm 1-hour average at 15% O_2

<u>Chiller System</u>
An inlet air cooler will be installed to increase the output of the turbines. A two-ton unit will provide sufficient cooling capacity to maintain the incoming air at or below the ISO standard temperature of 59F, such that power output is not adversely affected by increasing ambient temperature.

<u>Ammonia Storage</u>
The project will include a 12,000 gallon aqueous ammonia tank, built inside a secondary containment area capable of handling 110% of the tank volume. Estimated maximum ammonia use is about 40 pounds / 5.2 gallons per hour. Approximate annual aqueous ammonia consumption is 46,000 gallons. Consequently, there will be about four tank turnovers per year. Ammonia vapors generated during tank loading will be vented to the tank truck.

EMISSIONS

Emissions from the gas turbines are affected by the mode of operation and fuel. To maintain constant power output, combustion air to the turbines will be chilled whenever the air temperature exceeds approximately 65F. Consequently, the effect of ambient humidity and temperature will be minimal. From an emissions standpoint, the two operational modes to consider are start-up and normal 100% load. Because the SCR, oxidation catalyst, and water injection systems are ineffective or unusable during part of the start-up period, NOx and CO concentrations will exceed the normal control guarantees. Due to lower fuel consumption during starts, some mass emission rates may be lower than during the normal operation.

In the period before the SCR and oxidation catalyst are installed, the project will meet the alternative emission limit established by the Energy Commission and the Air Resources Board, namely a one-hour rolling average of 25 ppm NOx at 15% O_2.

Turbine Emissions

Maximum Emissions—Natural Gas Firing

Pollutant	Maximum Emissions, per Turbine			
	Without SCR + CO Catalyst		With SCR + CO Catalyst	
	lb/hr	lb/day	lb/hr	lb/day
NOx	26	613	2.6	61
CO	16	373	3.7	90
VOC	0.59	14	≤0.59[1]	14
PM_{10}	1.9	45	≥1.9[2]	45
SOx	0.56	13	≤0.56[1]	13
NH_3	--	--	3.8	90

Notes: 1. Does not consider reduction across oxidation catalyst
2. PM will increase in proportion to SO_2 oxidation

Maximum Emissions—Diesel Fuel Firing

Pollutant	Maximum Emissions, per Turbine			
	Without SCR + CO Catalyst		With SCR + CO Catalyst	
	lb/hr	lb/day	lb/hr	lb/day
NOx	68	1620	6.8[1]	162
CO	214	5150	54[2]	1290
VOC	0.13	3.0	≤0.13[3]	3.0
PM_{10}	37	882	≥37[4]	882
SOx	6.2	149	≤6.2[3]	149
NH_3	--	--	3.8	90

Notes: 1. With 90% reduction across SCR
2. With 75% reduction across oxidation catalyst
3. Does not consider reduction across oxidation catalyst
4. PM will increase in proportion to SO_2 oxidation

Estimated Annual NOx Emissions–Both Turbines Firing Both Fuels

Operating Mode	Duration, hours	Emission Rate, lb/hr	Emissions, tons/year
Natural Gas / 100% load	8315	2.6	21.2
Natural Gas / Start-up	365	15	5.6
Diesel Fuel / 100% load	70	6.8	0.47

Diesel Fuel / Start-up	10	41	0.41
Total:	8760	--	**27.7**

Annual NOx emissions are projected to estimate the required RTCs for the first year of operation, pursuant to Rule 2005. The estimate is based on operation with pollution controls, and assumes that the turbines operate 80 hours on diesel fuel with 10 one-hour starts, and 8680 hours on natural gas with 365 one-hour starts. For this analysis, the NOx emission rate during start-ups is estimated at six times the normal 100% operating rate.

RULE EVALUATION

RULE 212 – Standards for Approving Permits
Public notice will be sent to all addresses within a ¼-mile radius of the project, sent to those parties listed in subdivision (g) of the rule, including EPA Region IX, CARB, and the city, and published in a local newspaper.

Rule 218 – Continuous Emission Monitoring
The turbines require CEMS to verify compliance with emission limits. The system will comply with the requirements of Rule 218, and the facility will submit a CEMS application for AQMD review and approval prior to installation.

RULE 401 – Visible Emissions
Visible emissions from gas turbines are not expected under normal operating conditions.

RULE 402 – Nuisance
The gas turbines are not expected to cause any public nuisance under normal operating conditions.

RULE 403 – Fugitive Dust
Rule 403 will apply during construction of the project. Demolition of three small maintenance and storage buildings and minimal earth moving on the ±1-acre refinery site will not generate significant fugitive dust. Dust control measures such as water spraying will be used as necessary to ensure compliance with the rule.

RULE 407 – Liquid and Gaseous Air Contaminants
This rule limits CO emissions to 2000 ppm. As the turbines are subject to Rule 431.1, the sulfur limits in Rule 407 do not apply to the project. Data from Pratt & Whitney show CO concentrations below 2000 ppm for all operating scenarios. The use of the oxidation catalyst will reduce CO concentrations to approximately 6 ppm. Compliance will be verified by the CEMS.

RULE 409 – Combustion Contaminants
The rule limits PM emissions to 0.1 gr/scf at 12% CO_2.

PM emission rate: 6.6×10^{-3} lb/MMBtu $\times$ 282 MMBtu/hr = 1.9 lb/hr (AP-42)
Estimated exhaust gas flow rate: 141,000 dscfm $\times$ 60 min/hr = 8.5×10^{6} dscfh
Estimated CO_2 in exhaust gas: 2.7%

PM emissions at 12% CO_2:
1.9 lb/hr $\times$ 7000 gr/lb / 8.5×10^{6} dscfh $\times$ (12% CO_2 / 2.7% CO_2)

= 0.007 gr/scf

Thus the equipment will comply with Rule 409

RULE 431.1 – Sulfur Content of Natural Gas
Compliant gaseous fuel will be supplied by Southern California Gas Company. The typical sulfur content of fuel delivered to Santa Fe Springs is 0.12 gr/100 scf, with a maximum of 0.75 gr/100 scf, equivalent to 2 ppm and 12 ppm as H_2S, respectively.

RULE 431.2 – Sulfur Content of Diesel Fule
Diesel fuel will be used as back-up for up to 80 hours per year in the event of natural gas curtailment. Until June 1, 2004, CARB diesel containing less than 200 ppm sulfur will be provided. Subsequently, the back-up supply will meet the 15 ppm sulfur requirement of the rule.

RULE 475 –Electric Power Generating Equipment
PM emissions during natural gas firing and diesel fuel firing are estimated at 0.005 gr/scf and 0.009 gr/scf at 3% O_2, respectively, equivalent to 1.9 lb/hr and 3.7 lb/hr.

REGULATION XIII – New Source Review

The project is subject to the offsets, modeling, and BACT requirements of new source review.

Offsets

The Project is over the offset threshold for VOC, PM10 and CO. The new turbines will exceed add 5.1 tpy VOC, 16.2 tpy PM10 and 46 tpy CO. Therefore offsets are required.

Offsets for VOC, PM10, and CO are based on a calendar monthly average in accordance with Rule 1306(b). Offsets will be required prior to issuing the permit, however CEC has not yet provided the offsets for this project. CENCO submitted a request for offsets from the state bank on May 10, 2001. Other offset sources for this project are purchased ERCs and the AQMD's priority reserve, as outlined in Rule 1309.1.

Modeling

Modeling is required for CO and PM_{10} emissions per Rule 1303(b). The model must substantiate that the project does not exceed the most stringent ambient air quality standard or a significant change in air quality concentration, depending on the compliance status of each pollutant in the area. For pollutants that are in attainment of ambient air quality standards, modeling must demonstrate that the project emissions plus the background will not exceed the state standard. For non-attainment pollutants, the modeling must show compliance with significant change in air quality concentration. The project location is in attainment for NO_2 and CO, but non-attainment for PM_{10} and ozone.

CEC anticipates submitting the modeling results by July 17th.

BACT

BACT Emission Limits for Combined Cycle Gas Turbines

Pollutant	BACT Emission Limit
NOx	2.5 ppmv @ 15% O_2, 1 hour rolling average
CO	6 ppmv @ 15% O_2, 1 hour rolling average
VOC	2 ppmv @ 15% O_2, 1 hour rolling average **or** 0.0027 lb/MMBtu, HHV
PM_{10}	Emissions corresponding to natural gas with sulfur content of no more than 1 grain/100 scf
SOx	Emissions corresponding to natural gas with sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

Source: CARB, Guidance for Power Plant Citing and Best Available Control Technology, September 1999.

The following emission levels are proposed for this project. NOx, CO, and VOC concentrations are guaranteed emissions for baseload operating conditions.

Proposed Emissions Before Control Installation—Natural Gas Firing

Pollutant	Emission Limit

NOx	25 ppmv @ 15% O_2, 1 hour rolling average
CO	25 ppmv @ 15% O_2, 1 hour rolling average
VOC	2 ppmv @ 15% O_2, 1 hour rolling average
PM_{10}	Emissions equivalent to natural gas with sulfur content of no more than 1 grain/100 scf
SOx	Emissions equivalent to natural gas with sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

Proposed Emissions Before Control Installation—Diesel Fuel Firing

Pollutant	Emission Limit
NOx	70 ppmv @ 15% O_2, 1 hour rolling average
CO	350 ppmv @ 15% O_2, 1 hour rolling average
VOC	2 ppmv @ 15% O_2, 1 hour rolling average
PM_{10}	Emissions equivalent to natural gas with sulfur content of no more than 1 grain/100 scf
SOx	Emissions equivalent to natural gas with sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

Proposed Emissions After Control Installation—Natural Gas Firing

Pollutant	Emission Limit
NOx	5 ppmv @ 15% O_2, 1 hour rolling average
CO	6 ppmv @ 15% O_2, 1 hour rolling average
VOC	1 ppmv @ 15% O_2, 1 hour rolling average
PM_{10}	Emissions equivalent to natural gas with sulfur content of no more than 1 grain/100 scf
SOx	Emissions equivalent to natural gas with sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

Proposed Emissions After Control Installation—Diesel Fuel Firing

Pollutant	Emission Limit
NOx	7 ppmv @ 15% O_2, 1 hour rolling average
CO	60 ppmv @ 15% O_2, 1 hour rolling average
VOC	1 ppmv @ 15% O_2, 1 hour rolling average
PM_{10}	Emissions equivalent to natural gas with sulfur content of no more than 1 grain/100 scf
SOx	Emissions equivalent to natural gas with sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

Proposed Emissions for Combined Cycle—Natural Gas Firing

Pollutant	Emission Limit
NOx	2.5 ppmv @ 15% O_2, 1 hour rolling average
CO	6 ppmv @ 15% O_2, 1 hour rolling average
VOC	2 ppmv @ 15% O_2, 1 hour rolling average
PM_{10}	Emissions equivalent to natural gas with sulfur content of no more than 1 grain/100 scf
SOx	Emissions equivalent to natural gas with sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

Ammonia Emissions

Operation of the SCR will result in ammonia emissions. Based on the guarantee from Peerless Manufacturing Company, the project will meet the 1999 CARB BACT guidance limit of 5 ppm ammonia slip. A monitor will verify proper operation of the ammonia injection system.

RULE 1401 – Carcinogenic Air Contaminants

A Tier 2 screening risk assessment is being performed in accordance with the procedures in the *AQMD's Risk Assessment Procedures for Rules 1401 and 212*. Toxic pollutant emissions are based on factors published in AP-42. The results will determine whether further assessment by modeling will be required.

REGULATION XVII – Prevention of Significant Deterioration

Rule 1701 subjects these sources to PSD:

- Any new source or modification to an existing source where the emission increase is 100 or 250 tpy (depending on source category), or
- Any significant emissions increase at an existing major stationary source, or
- Any net emission increase at a major stationary source located within 10 km of a Class I area.

Rule 1702 (m)(1) lists the source categories subject to PSD. Any facility falling into the listed source categories which has emission of 100 tons per year or more of any contaminant regulated by the Act is considered a major stationary source.

One of the listed categories in paragraph (m)(1) is fossil fuel-fired steam electric plants with input of more than 250 MMBtu/hr. Since the CEC turbines are rated above 250 MMBtu/hr, and will generate steam after installation of the HRSG, they could be considered under this category. However, estimated NOx emissions from the project will be less than 100 tons per year. Therefore, installation of the new turbines is not considered a major stationary source under Rule 1702(m)(2).

The site is not located within 10 km of a Class I area or any other area specified in Part C of the Clean Air Act.

Furthermore, an unlisted source is subject to PSD if it emits 250 tpy of regulated contaminants [(m)(2)].

Therefore, an analysis under PSD is not required for the proposed turbines.

1701(b)(1) requires BACT for any net emission increase at any stationary source. Since there is a net emission increase in both NOx and SOx, BACT for these pollutants is required.

SOx BACT for this source is exclusive use of natural gas with sulfur content of 1 grain/scf. Natural gas is expected to meet this limit based on data provided by Southern California Gas Company.

NOx BACT for combined cycle equipment is 2.5 ppm averaged over 1 hour. With SCR and water injection, the project will meet this limit.

<u>Rule 2005 – NSR for Reclaim</u>

Rule 2005 applies to the NOx emissions from the turbines. The rule requires new sources to provide RTCs, perform a modeling analysis, and provide BACT.

RTCs

The facility will provide sufficient RTCs to offset emissions prior to the first year of operation on a 1-to-1 basis. CEC Power requests the use of the state ERC bank to provide NOx offsets for years 2001, 2002, and 2003.

Modeling

Modeling is being conducted per Rule 2005 to demonstrate that project NOx emissions plus background concentrations will not exceed the state NO_2 standard.

BACT

Until the SCR is installed, NOx will be controlled by a water injection system. After the installation of the SCR and CO catalysts, the turbines will meet the required BACT levels.

Additional Requirements for Major Sources

The project is a major polluting facility per Rules 2005 and 1303 (defined as sources emitting more than 10 tons of NOx or VOC, 70 tons of SOx or PM_{10}, or 100 tons of CO annually). Consequently, the applicant certifies that all major sources in the state under control of CENCO are in compliance with all applicable federal emissions standards. The applicant need not evaluate project alternatives as the project is subject to an emergency exemption from this CEQA requirement. A visibility analysis is not required because the project is not located near a Class I area

<u>Rule 2012 – Monitoring Recording and Record Keeping for RECLAIM NOx</u>
CEC will submit a CEMS application and plan to the District and install NOx CEMS within one year of installation of the turbines.

<u>Regulation XXX – Title V</u>
The facility is included in Title V. The Title V public notice will be combined with the Rule 212 notice.