San Joaquin Valley
Air Pollution Control District

April 19, 2001

DOCKET
01-EP-7
DATE APR 19 2001
RECD. APR 26 2001

Mark Kehoe
Hanford L.P.
4300 Railroad Avenue
Pittsburg, CA 94565-6006

Re: Notice of Preliminary Decision - Authority to Construct
Project Number: C-1010451

Dear Mr. Kehoe:

Enclosed for your review and comment is the District's analysis of Hanford L.P.'s application for an Authority to Construct for the installation of a 95.0 MW simple cycle gas turbine power plant, at 10550 Idaho Avenue in Hanford, CA.

In an effort to help alleviate California's electrical power shortage, the District has instituted an expedited permitting process for new or expanding power plants that can be on-line prior to September 30, 2001. Pursuant to the authority granted under Executive Order D-28-01 issued by Governor Davis, the District intends to issue such permits within 21 days after receiving a complete application. Towards that end, the District is asking that your comments be expedited and forwarded to the District within 7 days of the date of this notice. This is in contrast with the customary 30-day period provided for public comments.

While the District's expedited permitting process provides for a faster turnaround, it does not sacrifice substantive requirements designed to achieve environmental protection and public health. The proposed project complies with all applicable air emission standards.

All comments received within 7 days will be addressed before issuing the Authority to Construct. However, we will continue to accept written comments for 30 days from the date of publication of this notice. Such comments will be reviewed and, if necessary, the Authority to Construct will be supplemented to incorporate such comments.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Samir Sheikh of Permit Services at (559) 230-5897.

Sincerely,

Seyed Sadredin
Director of Permit Services

SS:sqs/EV
Enclosures
c: David Warner, Permit Services Manager
Doug Wheeler, GWF Power Systems – Hanford L.P.
Bob Eller, California Energy Commission

Hanford Sentinel

NOTICE OF PRELIMINARY DECISION
AUTHORITY TO CONSTRUCT FOR NEW POWER PLANT

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District solicits public comment on the proposed issuance of an Authority to Construct to GWF Power Systems Co. – Hanford L.P. for the installation of one 95 MW peaking power plant powered by two 47.5 MW General Electric LM6000 gas turbines, at 10550 Idaho Avenue in Hanford, CA.

In an effort to help alleviate California's electrical power shortage, the District has instituted an expedited permitting process for new or expanding power plants that can be on-line prior to September 30, 2001. Pursuant to the authority granted under Executive Order D-28-01 issued by Governor Davis, the District intends to issue such permits within 21 days after receiving a complete application. Towards that end, the District is asking that public comments be expedited and forwarded to the District within 7 days of the date of this notice. This is in contrast with the customary 30-day period provided for public comments.

While the District's expedited permitting process provides for a faster turnaround, it does not sacrifice substantive requirements designed to achieve environmental protection and public health. The proposed project complies with all applicable air emission standards.

The analysis of the regulatory basis for this proposed action on Project #C-1010451 will be available for public inspection at the District office. All comments received within 7 days will be addressed before issuing the Authority to Construct. However, we will continue to accept written comments for 30 days from the date of publication of this notice. Such comments will be reviewed and, if necessary, the Authority to Construct will be supplemented to incorporate such comments. Comments must be submitted to **SEYED SADREDIN, DIRECTOR OF PERMIT SERVICES, SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.**

AUTHORITY TO CONSTRUCT
APPLICATION REVIEW
Gas Turbine Simple Cycle Peaker Plant

Facility Name:	Hanford LP
Mailing Address:	4300 Railroad Avenue Pittsburg, CA 94565-6006
Contacts:	Doug Wheeler, Vice President (925) 431-1443
	Mark Kehoe, Director – Environmental and Safety Programs (925) 431-1440
Application #s:	C-603-11-0 and -12-0
Project #:	1010451
Application Received:	04/09/01
Deemed Complete:	04/12/01
Reviewing Engineer:	Samir Sheikh / Errol Villegas
Date:	04/19/01
Lead Engineer:	Joven Refuerzo

I. Proposal

The applicant has requested Authority to Construct permits for the installation of two 47.5 MW General Electric LM6000 PC Sprint natural gas fired gas turbine engines (GTEs) with a water spray premixed combustion system, a Selective Catalytic Reduction (SCR) system and a CO & VOC catalyst. The GTEs will be installed in a simple cycle configuration (no heat recovery), will be served by a NO_X Continuous Emissions Monitoring System (CEMS), and will be utilized to generate electric power for a 95.0 MW peaking power plant.

The Hanford Energy Park Peaker (HEPP) is expected to operate as a base-loaded peaking facility. Each LM6000 PC Sprint will have a maximum heat input rate of 459.6 MMBtu/hr (HHV) as a simple cycle operating unit. Construction is expected to begin in May 2001 and the unit will be operational in September 2001. The initial cycle of operation will begin September 2001 and end in December 2001. The GTEs will operate 2,000 hours with 200 startup/shutdown events during the 2001 period. Beginning with the second year of operations, the HEPP will operate a maximum of

8,000 hours per year and a maximum of 300 startup/shutdown events. HEPP does not wish to be restricted to a specific number of hours of operation and startup/shutdown events per quarter. Actual emissions from the facility will vary depending on electricity demand from California. A hypothetical operating scenario has been developed for purposes of demonstrating that the project will comply with SJVAPCD emission offset requirements with the ERC's that have already been obtained for this project.

Table 1. Hypothetical Operating Scenario

	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual
Number of Startups/shutdown events	50	100	100	50	300
Number of Full Load Hours	2,000	2,000	2,000	2,000	8,000

II. Applicable Rules

Rule 1080 Stack Monitoring (Adopted June 18, 1992, Amended December 17, 1992)

Rule 1081 Source Sampling (Adopted April 11, 1991, Last Amended December 16, 1993)

Rule 2010 Permits Required (Adopted May 21, 1992, Amended December 17, 1992)

Rule 2201 New and Modified Stationary Source Review Rule (Adopted September 19,1991, Amended June 15, 1995)

Rule 2520 Federally Mandated Operating Permits (Adopted June 15, 1995)

Rule 2540 Acid Rain Program (Adopted November 13, 1997)

Rule 4001 New Source Performance Standards (Adopted April 11, 1991, Last Amended April 14, 1999)

Rule 4101 Visible Emissions (Adopted May 21, 1992, Amended December 17, 1992)

Rule 4102 Nuisance (Adopted May 21, 1992, Amended December 17, 1992)

Rule 4201 Particulate Matter Concentration (Adopted April 11, 1991, Last Amended May 19, 1994)

Rule 4301 Fuel Burning Equipment (Adopted May 21, 1992, Amended December 17, 1992) - *Not applicable. The GTEs do not produce power by indirect heat transfer.*

Rule 4703 Stationary Gas Turbines (Adopted August 18, 1994, Amended October 16, 1997)

Rule 4801 Sulfur Compounds (Adopted May 21, 1992, Amended December 17, 1992)

California Environmental Quality Act (CEQA)

III. Project Location

The project is located in Hanford, Kings County, CA (a CO attainment area). The peaker site is a 5-acre parcel adjacent to the existing GWF Hanford Cogeneration plant just north of Idaho Avenue, between the existing GWF facility to the west and the Burlington Northern and Santa Fe Railway tracks to the east. The area is situated in U.S. Census tract 0012-02 of Kings County.

This site is not within 1,000 feet of a school. Therefore the notification requirements of CH&SC 42301.6 do not apply.

IV. Equipment Listing

C-603-11-0: 47.5 MW General Electric Model LM6000 natural gas fired gas turbine engine (GTE) with water spray premixed combustion systems, served by selective catalytic reduction (SCR) system and oxidation catalyst.

C-603-12-0: 47.5 MW General Electric Model LM6000 natural gas fired gas turbine engine (GTE) with water spray premixed combustion systems, served by selective catalytic reduction (SCR) system and oxidation catalyst.

V. Process Description

Hanford LP proposes to operate a 95.0 MW power plant located adjacent to the existing GWF Hanford Cogeneration plant. The simple-cycle gas turbines firing only natural gas will be used to provide power to California's electricity grid during periods of high electricity demand.

The HEPP will be a nominal 95 MW (gross) natural gas-fired simple cycle gas turbine power plant (consisting of two gas turbine/generators), with a 1.2 mile 115-kV transmission line with an interconnection to the existing Pacific Gas and Electric Company (PG&E) 115-kV Henrietta-Kingsburg transmission line at the corner of 11th Avenue and Jackson Avenue to the south. The dual circuit 115-kV line will be supported on single poles that will leave the plant west along Idaho and turn south on 11th Avenue to Jackson Avenue.

Natural gas for the HEPP will be delivered via a 16" gas line being installed by So-Cal Gas Company from their gas distribution system 2.8 miles northwest of the HEPP at the intersection of 11th Avenue and Hanford-Armona Road. The gas line will follow an easement on 11th Avenue south to Idaho Avenue before turning east toward the plant.

Domestic water will be supplied from the Hanford municipal water system and will be used for industrial purposes. Groundwater from on-site water well at the adjacent Hanford Cogeneration Plant will supply process-cooling water for the gas turbine inlet and NO_X control (during first year of operation). The dual Gas TurbineEngine (GTE) units will use 140 gpm of process water that has been demineralized by a combination water demineralizer and reverse osmosis water treatment unit located at the Hanford Cogeneration facility. Approximately 20 gpm of lowdown from the GTE units will be diverted to the existing cooling tower for the cogen facility.

See plot plan in Appendix B.

VI. Control Equipment Evaluation

The new turbines will each be equipped with water spray premixed combustion systems and will exhaust into a Selective Catalytic Reduction [SCR] system, and a CO & VOC catalyst.

Emissions from natural gas-fired turbines include CO, NO_X, PM_{10}, SO_X, and VOC.

NO_X is the major pollutant of concern when combusting natural gas. Virtually all gas turbine NO_X emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule. There are two mechanisms by which NO_X is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_X and prompt NO_X), and 2) the conversion of nitrogen chemically bound in the fuel (fuel NO_X).

Thermal NO_X is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NO_X. Prompt NO_X is formed in both fuel-rich flame zones and dry low NO_X (DLN) combustion zones. The contribution of prompt NO_X to overall NO_X emissions is relatively small in conventional near-stoichiometric combustors, but this contribution is an increasingly significant percentage of overall thermal NO_X emissions in DLN combustors. For this reason prompt NO_X becomes an important consideration for DLN combustor designs, and establishes a minimum NO_X level attainable in lean mixtures.

Fuel NO_X is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N_2 in some natural gas, does not contribute significantly to fuel NO_X formation. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content in the fuel. When compared to thermal NO_X, fuel NO_X is not currently a major contributor to overall NO_X emissions from stationary gas turbines firing natural gas.

The level of NO_X formation in a gas turbine, and hence the NO_X emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_X generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine.

The design of the combustor is the most important factor influencing the formation of NO_X. Design parameters controlling air/fuel ratio and the introduction of cooling air into the combustor strongly influence thermal NO_X formation. Thermal NO_X formation is primarily a function of flame temperature and residence time. The extent of fuel/air mixing prior to combustion also affects NO_X formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_X production takes place. Injecting water or steam into a conventional combustor provides a heat sink that effectively reduces peak flame temperature, thereby reducing thermal NO_X formation. Premixing air and fuel at a lean ratio approaching the lean flammability limit (approximately 50% excess air) significantly reduces peak flame temperature, resulting in minimum NO_X formation during combustion. This is known as dry low NO_X (DLN) combustion.

Selective Catalytic Reduction systems selectively reduce NO_X emissions by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. SCR is capable of over 90 percent NO_X reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 °F. Exhaust gas temperatures greater than the upper limit (750 °F) will cause NO_X and NH_3 to pass through the catalyst unreacted.

The exhaust from the GTE is too high (~850 °F) to be used with a standard SCR system without first cooling the exhaust. The applicant proposes to introduce fresh air in the GTE exhaust upstream of the SCR system to reduce the exhaust temperature to approximately 750 °F.

A. Best Available Control Technology (BACT) Requirement

1. Applicability:

Per Rule 2201 Sections 4.1.1 and 4.1.1.1, BACT shall be applied to a new or modified emissions unit if the new unit or modification results in an increase in permitted emissions (BACT IPE) greater than 2 lb/day for NO_X, CO (non-attainment area), VOC, PM_{10}, or SO_X. In a CO attainment area, the CO NSR balance must also exceed 550 lb/day to trigger BACT.

As seen in Section VII of this evaluation, the applicant is proposing to install two new emissions units with BACT IPEs greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, CO, VOC, PM_{10}, and SO_X criteria pollutants since there are IPEs greater than 2 lbs/day and the CO NSR Balance is greater than 550 lbs/day.

2. BACT Guidance:

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule. The District BACT Clearinghouse recently included a new BACT Guideline applicable to these turbine installations [Simple Cycle Gas Fired Turbines less than 50 MW, Powering an Electrical Generation Operation]. (See Appendix I) However, the new BACT guideline did not address Best Available Control Technology for CO emissions since BACT was not triggered for that specific project. Therefore, this BACT Analysis will revise the new BACT guideline to include BACT for CO emissions. See top down BACT analysis in Appendix C.

3. BACT Summary:

BACT has been satisfied by the following:

NO_X: 3.7 ppmv @ 15% O2 (3 hour rolling average) using water injection, SCR with ammonia injection, an oxidation catalyst and natural gas fuel

CO: 6.0 ppmv @ 15% O2 (3 hour rolling average), oxidation catalyst, and natural gas fuel

VOC: 2.0 ppmv @ 15% O2 (3 hour rolling average)

PM_{10}: Air inlet filter cooler, lube oil vent coalescer, and natural gas fuel

SO_X: Natural gas with a sulfur content of 0.25 gr/100 scf

4. Top-Down Best Available Control Technology (BACT) Analysis for Permit Units C-603-11-0 and –12-0:

See Appendix C.

VII. <u>Emission Calculations</u>

A. Assumptions

- Per the applicant, both GTEs will be fired only on natural gas.

- Natural gas F factor is 8,710 dscf/MMBtu (@ 68 F per EPA 40 CFR 60 Appendix B method 19)
- Higher Heating Value of natural gas is 1,000 Btu/scf
- The heat input rating provided by the applicant is 459.6 MMBtu/hr
- All particulate matter is PM_{10} (Ref. CARB PM Inventory Weight Fractions, 02/13/86).
- Emissions are based on 24 hours per day and 8,000 hours per year of operation. (proposed by Applicant)
- Startup/shutdown events will not exceed 300 events per year. (per applicant)

B. Emission Factors

For the two new turbines, the emissions factors for NO_X, CO, and VOC are provided by the applicant and are calculated at 15% O_2. The PM_{10} emission factor is taken from AP-42 Table 3.1-2a (4/00) (Appendix D) and the SO_X emission factor is derived from the guaranteed sulfur limit of 0.25 gr S/100 scf.

Emissions estimates are for one GTE.

Table 2. Emission Factors (@ normal baseload)

	[ppmv @ 15% O_2]	[lb/MMBtu]
*NO_X	3.7	0.0136
*CO	6.0	0.0135
*VOC	2.0 (as CH_4)	0.0026
PM_{10}	--	0.0066
**SO_X	0.25 gr/100 scf	0.00071

* See Appendix E for conversion spreadsheet.
** 0.25 ~~gr-S~~/100 ~~dscf~~ x 1 ~~lb-S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb-S~~ x 1 ~~scf~~/1000 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu = 0.00071 lb/MMBtu

Startup/Shutdown Emission Rates

Below is a summary of the maximum expected emissions during an average startup/shutdown event of 1-hour duration.

Table 3. Startup/Shutdown Emissions (1-hour duration)*

	NO_X (lb/event)	CO (lb/event)	VOC (lb/event)	PM_{10} (lb/event)**	SO_X (lb/event)**
Mass Emission Rate (perGTE)	7.7	7.7	0.68	3.03	0.33

* Pursuant to the turbine vendor, "A start-up/shutdown event is estimated to be completed in 10 minutes; however, for simplification the emissions for a start-up/shutdown event are calculated as hourly emissions with the 10 minute start-up emissions being added to 50 minutes of base load operating emissions."
** Pursuant to the turbine vendor, "emissions of PM_{10} and SO_X are a function of the quantity of fuel burned, thus they will be highest when the turbine operates at maximum fuel consumption."

C. Potential to Emit

Example Calculations: (@ normal baseload) (i.e. excluding startup/shutdown)

PE_{NOx} = (459.6 MMBtu/hr) ∗ (0.0136 lb/MMBtu)
= 6.25 lb NO_X/hr

= (459.6 MMBtu/hr) ∗ (0.0136 lb/MMBtu) ∗ (24 hr/day)
= 150.0 lb NO_X/day

= (459.6 MMBtu/hr) ∗ (0.0136 lb/MMBtu) ∗ (8,000 hr/year)
= 50,004 lb NO_X/year

PE_{CO} = (459.6 MMBtu/hr) ∗ (0.0135 lb/MMBtu)
= 6.20 lb CO/hr

= (459.6 MMBtu/hr) ∗ (0.0135 lb/MMBtu) ∗ (24 hr/day)
= 148.9 lb CO/day

= (459.6 MMBtu/hr) ∗ (0.0135 lb/MMBtu) ∗ (8,000 hr/year)
= 49,637 lb CO/year

PE_{VOC} = (459.6 MMBtu/hr) ∗ (0.0026 lb/MMBtu)
= 1.19 lb VOC/hr

= (459.6 MMBtu/hr) ∗ (0.0026 lb/MMBtu) ∗ (24 hr/day)
= 28.7 lb VOC/day

= (459.6 MMBtu/hr) ∗ (0.0026 lb/MMBtu) ∗ (8,000 hr/year)
= 9,560 lb VOC/year

PE_{PM10} = (459.6 MMBtu/hr) ∗ (0.0066 lb/MMBtu)
= 3.03 lb PM_{10}/hr

= (459.6 MMBtu/hr) ∗ (0.0066 lb/MMBtu) ∗ (24 hr/day)
= 72.8 lb PM_{10}/day

= (459.6 MMBtu/hr) ∗ (0.0066 lb/MMBtu) ∗ (8,000 hr/year)
= 24,267 lb PM_{10}/year

PE_{SOx} = (459.6 MMBtu/hr) ∗ (0.00071 lb/MMBtu)
= 0.33 lb SO_X/hr

= (459.6 MMBtu/hr) ∗ (0.00071 lb/MMBtu) ∗ (24 hr/day)
= 7.8 lb SO_X/day

= (459.6 MMBtu/hr) * (0.00071 lb/MMBtu) * (8,000 hr/year)
= 2,611 lb SO_X/year

Maximum daily emissions are based on 24 hours of worst-case emission rates. For NO_X and CO emissions, the worst-case daily emission rate is maximized on a day, which includes a startup/shutdown event. For VOC, PM_{10} and SO_X emissions, the maximum daily emissions are equivalent to the operating at normal baseload conditions, since emissions are less than or equal to when including a startup/shutdown event.

Example Calculations: (Worst-case)

PE_{NOx} = [(7.7 lb NO_X/hr-event) * (1 event)] + [(459.6 MMBtu/hr) * (0.0136 lb/MMBtu) * (23 hr/day)]
= 151.5 lb NO_X/day

PE_{CO} = [(7.7 lb CO/hr-event) * (1 event)] + [(459.6 MMBtu/hr) * (0.0135 lb/MMBtu) * (23 hr/day)]
= 150.3 lb CO/day

Maximum annual emissions will be based upon 8,000 hours of operation and 300 startup/shutdown events per year.

PE_{NOx} = [(7.7 lb NO_X/event) * (300 event/year)] + [(459.6 MMBtu/hr) * (0.0136 lb/MMBtu) * (8,000 hr/yr)]
= 52,314 lb NO_X/year

PE_{CO} = [(7.7 lb CO/event) * (300 event/year)] + [(459.6 MMBtu/hr) * (0.0135 lb/MMBtu) * (8,000 hr/year)]
= 51,947 lb CO/year

PE_{VOC} = [(0.68 lb VOC/event) * (300 event/year)] + [(459.6 MMBtu/hr) * (0.0026 lb/MMBtu) * (8,000 hr/year)]
= 9,764 lb VOC/year

PE_{PM10} = [(3.03 lb PM_{10}/event) * (300 event/year)] + [(459.6 MMBtu/hr) * (0.0066 lb/MMBtu) * (8,000 hr/year)]
= 25,176 lb PM_{10}/year

PE_{SOx} = [(0.33 lb SO_X/event) * (300 event/year)] + [(459.6 MMBtu/hr) * (0.00071 lb/MMBtu) * (8,000 hr/yr)]
= 2,710 lb SO_X/year

Summary of emissions: (Worst-case)

Table 4. Potential to Emit (PE) (Each GTE)			
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Annual Emissions (lb/year)
NO_X	7.7*	151.5	52,314
CO	7.7*	150.3	51,947
VOC	1.19	28.7	9,764
PM_{10}	3.03	72.8	25,176
SO_X	0.33	7.8	2,710

* Based upon startup/shutdown emissions.

Table 5. Potential to Emit (PE) (Combined)			
	Daily Emissions (lb/day)	Annual Emissions (lb/year)	Annual Emissions (Tons/year)
NO_X	303.0	104,628	52.31
CO	300.6	103,894	51.95
VOC	57.4	19,528	9.76
PM_{10}	145.6	50,352	25.18
SO_X	15.6	5,420	2.71

D. Best Available Control Technology (BACT) Requirement

For a new emissions unit, the increase in permitted emissions for determining if BACT is triggered is equal to the potential to emit (PE):

BACT IPE = PE_{new}

Summary of BACT IPE (based on maximum hourly emissions):

Table 6. BACT Increase in Permitted Emissions					
Permit Unit	NO_X [lb/day]	CO [lb/day]	VOC [lb/day]	PM_{10} [lb/day]	SO_X [lb/day]
C-603-11-0	151.5	150.3	28.7	72.8	7.8
C-603-12-0	151.5	150.3	28.7	72.8	7.8
BACT Triggered?	Yes	Yes	Yes	Yes	Yes

BACT is triggered for NO_X, VOC, PM_{10} and SO_X for the new turbines. BACT is also required for CO because the Stationary Source NSR Balance for CO exceeds 550 lb/day and the increase in permitted emissions will exceed 2 lb/day. As demonstrated in Appendix C, BACT is satisfied for all criteria pollutants.

E. Offsets

1. Stationary Source Potential to Emit

The purpose of calculating stationary source potential to emit (SSPE) is to determine if offsets are required for NO_X or VOC. Per Rule 2201 Section 4.2.3, the offset trigger levels are 10 tons/year for NO_X or VOC. Since the proposed project does result in an increase in NO_X and VOC emissions, SSPE calculations are required.

Table 7: Stationary Source Potential to Emit (SSPE)

Unit	Status	NO_X [lb/year]	VOC [lb/year]
C-603-1-2	Permit	89,425	21,900
C-603-2-0	Permit	0	0
C-603-3-0	Permit	0	0
C-603-6-1	Permit	0	0
Pre-project SSPE		89,425	21,900
C-603-11-0	ATC, Hanford Energy Park Peaker	52,314	9,764
C-603-12-0	ATC, Hanford Energy Park Peaker	52,314	9,764
Post-project SSPE [lb/yr]		194,053	41,428
Post-project SSPE [tons/yr]		97.0	20.7
Offset threshold [tons/yr]		10	10
Offsets required?		Yes	Yes

The offset trigger thresholds for NO_X and VOC emissions were exceeded before this installation. Therefore, offsets for NO_X and VOC are required.

2. NSR Balance

New Source Review (NSR) balance is calculated to determine if offsets or public notice are required for CO, PM_{10}, or SO_X. Per Rule 2201 Section 4.2.2, the offset trigger levels are 550 lb/day, 80 lb/day, and 150 lb/day, respectively and the public notice thresholds for CO, PM_{10} and SO_X are 550 lb/day, 70 lb/day and 140 lb/day respectively. This project results in daily emissions increases in CO, PM_{10}, and SO_X emissions, therefore NSR balance calculations are required.

Table 6. NSR Balance				
Unit	Status	CO [lb/day]	PM_{10} [lb/day]	SO_X [lb/day]
C-603-1-2	Permit	544.0	80.0	245.0
C-603-2-0	Permit	0.0	0.5	0.0
C-603-3-0	Permit	0.0	0.8	0.0
C-603-6-1	Permit	0.0	0.0	0.0
Pre-project NSR Balance		544.0	81.3	245.0
C-603-11-0	ATC, Hanford Energy Park Peaker	150.3	72.8	7.8
C-603-12-0	ATC, Hanford Energy Park Peaker	150.3	72.8	7.8
Post-project NSR Balance		844.6	226.9	260.6
Offset threshold		550	80	150
Offsets triggered?		Yes	Yes	Yes
Public Notice Threshold		550	70	140
Public Notice Triggered?		Yes	Yes	Yes

The NSR balance does exceed the offset and public notice thresholds for all of the above criteria pollutants. Therefore, offsets and public notice for CO, PM_{10}, and SO_X will be required.

3. Offsets Required

SSPE:

Per Rule 2201 Section 6.8.2.1, the quantity of offsets in pounds per year for NO_X and VOC is calculated as follows for sources with SSPE greater than 10 tons per year before implementing the project being evaluated.

Offset = [SSPE (after) – SSPE (before)] * Offset Ratio

Where, Offset Ratio = Distance and interpollutant ratio of Rule 2201 Section 4.0

NO_X Offset Calculations:

NO_X $SSPE_{after}$ = 194,053 lb/year
NO_X $SSPE_{before}$ = 89,425 lb/year
Offsets = 194,053 – 89,425
= 104,628 lb/year

As discussed in the proposal section of this evaluation, the hypothetical operating scenario for each turbine unit assumes 50 startup/shutdown events in the 1^{st} and 4^{th} Quarters and 100 startup/shutdown events occurring in the 2^{nd} and 3^{rd} Quarters. Calculating the appropriate quarterly emissions to be offset is as follows:

$PE_{1st\ Qtr}$ = [(7.7 lb NO_X/event) * (50 event/1^{st} qtr) + 459.6 MMBtu/hr) * (0.0136 lb/MMBtu) * (2,000 hr/qtr)] + [(7.7 lb NO_X/event) * (50 event/1^{st} qtr) + (459.6 MMBtu/hr) * (0.0136 lb/MMBtu) * (2,000 hr/qtr)]

= 25,772 lbs of NO_X

$PE_{2nd\ Qtr}$ = [(7.7 lb NO_X/event) * (100 event/2nd qtr) + (459.6 MMBtu/hr) * (0.0136 lb/MMBtu) * (2,000 hr/qtr)] + [(7.7 lb NO_X/event) * (100 event/2nd qtr) + (459.6 MMBtu/hr) * (0.0136 lb/MMBtu) * (2,000 hr/qtr)]
= 26,542 lbs of NO_X

$PE_{3rd\ Qtr}$ = [(7.7 lb NO_X/event) * (100 event/3rd qtr) + (459.6 MMBtu/hr) * (0.0136 lb/MMBtu) * (2,000 hr/qtr)] + [(7.7 lb NO_X/event) * (100 event/3rd qtr) + (459.6 MMBtu/hr) * (0.0136 lb/MMBtu) * (2,000 hr/qtr)]
= 26,542 lbs of NO_X

$PE_{4th\ Qtr}$ = [(7.7 lb NO_X/event) * (50 event/4th qtr) + 459.6 MMBtu/hr) * (0.0136 lb/MMBtu) * (2,000 hr/qtr)] + [(7.7 lb NO_X/event) * (50 event/4th qtr) + (459.6 MMBtu/hr) * (0.0136 lb/MMBtu) * (2,000 hr/qtr)]
= 25,772 lbs of NO_X

Assuming an offset ratio of 1.5: 1, the amount of NO_X ERC credits needed to be surrendered to the District is:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
38,658	39,813	39,813	38,658

The applicant has stated that the facility plans to use ERC certificate C-278-2 to offset the increases in NO_X emissions associated with this project. Certificate C-278-2 has available quarterly NO_X credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #C-278-2	19,218	41,221	63,223	41,221

As seen above, the facility is lacking sufficient credits to fully offset the quarterly emissions occurring in the 1st quarter. However, pursuant to District Rule 2201, Section 4.2.5.5, actual emissions reductions for NO_X that occurred from April through November may be used to offset increases in NO_X during any period of the year. Therefore, since the facility has surplus credits available, which occurred within the 3rd quarter, credits from that quarter can offsets the deficient emissions in the 1st quarter.

VOC Offset Calculations:

VOC $SSPE_{after}$ = 41,428 lb/year
VOC $SSPE_{before}$ = 21,900 lb/year
Offsets = 41,428 – 21,900
= 19,528 lb/year

As discussed above, calculating the appropriate quarterly emissions to be offset is as follows:

$PE_{1st\ Qtr}$ = [(0.68 lb VOC/event) ∗ (50 event/1st qtr) + 459.6 MMBtu/hr) ∗ (0.0026 lb/MMBtu) ∗ (2,000 hr/qtr)] + [(0.68 lb VOC/event) ∗ (50 event/1st qtr) + (459.6 MMBtu/hr) ∗ (0.0026 lb/MMBtu) ∗ (2,000 hr/qtr)]
= 4,848 lbs of VOC

$PE_{2nd\ Qtr}$ = [(0.68 lb VOC/event) ∗ (100 event/2nd qtr) + (459.6 MMBtu/hr) ∗ (0.0026 lb/MMBtu) ∗ (2,000 hr/qtr)] + [(0.68 lb VOC/event) ∗ (100 event/2nd qtr) + (459.6 MMBtu/hr) ∗ (0.0026 lb/MMBtu) ∗ (2,000 hr/qtr)]
= 4,916 lbs of VOC

$PE_{3rd\ Qtr}$ = [(0.68 lb VOC/event) ∗ (100 event/3rd qtr) + (459.6 MMBtu/hr) ∗ (0.0026 lb/MMBtu) ∗ (2,000 hr/qtr)] + [(0.68 lb VOC/event) ∗ (100 event/3rd qtr) + (459.6 MMBtu/hr) ∗ (0.0026 lb/MMBtu) ∗ (2,000 hr/qtr)]
= 4,916 lbs of VOC

$PE_{4th\ Qtr}$ = [(0.68 lb VOC/event) ∗ (50 event/4th qtr) + 459.6 MMBtu/hr) ∗ (0.0026 lb/MMBtu) ∗ (2,000 hr/qtr)] + [(0.68 lb VOC/event) ∗ (50 event/4th qtr) + (459.6 MMBtu/hr) ∗ (0.0026 lb/MMBtu) ∗ (2,000 hr/qtr)]
= 4,848 lbs of VOC

Assuming an offset ratio of 1.5: 1, the amount of VOC ERC credits needed to be surrendered to the District is:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
7,272	7,374	7,374	7,272

The applicant has stated that the facility plans to use ERC certificate S-1538-1 to offset the increases in VOC emissions associated with this project. Certificate S-1538-1 has available quarterly VOC credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #S-1538-1	12,029	13,701	14,447	13,112

With the above ERC certificate, the facility has sufficient offset credits, to offset increases in VOC emissions.

NSR Balance:

Per Rule 2201 Section 6.8.1, the quantity of offsets in pounds per year for CO, PM_{10}, and SO_X is calculated as follows:

Offset = Sum of PE ∗ Offset Ratio

Where, Offset Ratio = Distance and interpollutant ratio of Rule 2201 Section 4.0
Sum of PE = Sum of annual potential to emit from all new or modified emissions units in pounds per year...

CO Offset Calculations:
CO offsets are triggered by CO NSR Balance emissions in excess of 550 lb/day for the facility. As shown previously, the NSR Balance for CO, after this project, is 844.6 lb/day, so offset requirements are triggered.

However, pursuant to Section 4.2.1.1 of Rule 2201, "Offsets shall not be required for: increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, pursuant to Section 4.3.2.1, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with reasonable progress, and will not cause or contribute to a violation of Ambient Air Quality Standards (AAQS)."

The Technical Services Section of the San Joaquin Valley Unified Air Pollution Control District performed a CO modeling run, using the EPA ISCST3 air dispersion model, to determine if the CO emissions from the new turbines would exceed the State and Federal AAQS. Modeling of the worst case 1 hour and 8 hour CO impacts were performed. These values were added to the worst case ambient concentration (background) measured and compared to the ambient air quality standards. Results of the modeling are presented below:

Table 7. Ambient Modeling Results for CO

	1 hr std	8 hr std
AAQS (ug/m^3)	23,000	10,000
Worst case ambient (background) (ug/m^3)	11,980	8,865.20
Modeled impact (ug/m^3)	0.25	0.14
Modeled ambient CO (ug/m^3)	11,980.25	8,865.34

This modeling demonstrates that the proposed increase in CO emissions will not cause a violation of the CO ambient air quality standards. Therefore, the increase in CO emissions is exempt from offsets by Rule 2201 section 4.2.1.1.

PM_{10} Offset Calculations:
PM_{10} offsets are triggered by PM_{10} NSR Balance emissions in excess of 80 lb/day for the facility. As shown in Table 6, the NSR Balance for PM_{10}, after this project, is 226.9 lb/day, so offset requirements are triggered.

Prior to the current project being evaluated, the facility's NSR balance exceeded the offset threshold, and the facility offset the pre-project emissions during their previous permitting action. The amount of offsets required will only be the emissions increases associated with this project.

Offset = $IPE_{current\ project}$ * Offset Ratio

Where, $IPE_{current\ project}$ = Annual Increases in Permitted Emissions for the new emissions units (C-603-11-0 & -12-0)

$IPE_{current\ project}$ = 25,176 lb PM_{10}/year + 25,176 lb PM_{10}/year
= 50,352 lb PM_{10}/year

As discussed above, calculating the appropriate quarterly emissions to be offset is as follows:

$PE_{1st\ Qtr}$ = [(3.03 lb PM_{10}/event) ∗ (50 event/1st qtr) + 459.6 MMBtu/hr) ∗ (0.0066 lb/MMBtu) ∗ (2,000 hr/qtr)] + [(3.03 lb PM_{10}/event) ∗ (50 event/1st qtr) + (459.6 MMBtu/hr) ∗ (0.0066 lb/MMBtu) ∗ (2,000 hr/qtr)]
= 12,436 lbs of PM_{10}

$PE_{2nd\ Qtr}$ = [(3.03 lb PM_{10}/event) ∗ (100 event/2nd qtr) + (459.6 MMBtu/hr) ∗ (0.0066 lb/MMBtu) ∗ (2,000 hr/qtr)] + [(3.03 lb PM_{10}/event) ∗ (100 event/2nd qtr) + (459.6 MMBtu/hr) ∗ (0.0066 lb/MMBtu) ∗ (2,000 hr/qtr)]
= 12,740 lbs of PM_{10}

$PE_{3rd\ Qtr}$ = [(3.03 lb PM_{10}/event) ∗ (100 event/3rd qtr) + (459.6 MMBtu/hr) ∗ (0.0066 lb/MMBtu) ∗ (2,000 hr/qtr)] + [(3.03 lb PM_{10}/event) ∗ (100 event/3rd qtr) + (459.6 MMBtu/hr) ∗ (0.0066 lb/MMBtu) ∗ (2,000 hr/qtr)]
= 12,740 lbs of PM_{10}

$PE_{4th\ Qtr}$ = [(3.03 lb PM_{10}/event) ∗ (50 event/4th qtr) + 459.6 MMBtu/hr) ∗ (0.0066 lb/MMBtu) ∗ (2,000 hr/qtr)] + [(3.03 lb PM_{10}/event) ∗ (50 event/4th qtr) + (459.6 MMBtu/hr) ∗ (0.0066 lb/MMBtu) ∗ (2,000 hr/qtr)]
= 12,436 lbs of PM_{10}

Assuming an offset ratio of 1.5: 1, the amount of PM_{10} ERC credits needed to be surrendered to the District is:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
18,654	19,110	19,110	18,654

The applicant has stated that the facility plans to use ERC certificates C-0366-4 and C-0382-4 to offset the increases in PM_{10} emissions associated with this project. Certificates C-0366-4 and C-0382-4 have available quarterly PM_{10} credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #C-0366-4	5,699	5,087	7,081	6,732
ERC #C-0382-4	3,075	3,075	3,075	3,075
Total:	8,775	8,164	10,159	9,811

As seen above, the facility is lacking sufficient credits to fully offset the emissions increases for PM_{10}. As proposed by the applicant, in order to satisfy District offset requirements the applicant has proposed providing SO_X reductions in place of PM_{10} reductions. District Rule 2201 Section 4.2.5.2 allows such interpollutant substitutions provided the applicant shows that the substitution will not cause or contribute to the violation of an ambient air quality standard and that the appropriate interpollutant offset ratio is utilized.

Hanford LP, has proposed to provide SO_X credits to offset PM_{10} credits at an offset ratio of 1:1. To support this interpollutant substitution ratio, the facility has provided information from a memo dated March 23, 1998 from a Mr. Terry McGuire, Chief of the Technical Support Division of the California Air Resources Board (CARB) (See Appendix F). In the memo, it is assumed that the 1:1 ratio is acceptable since one pound of SO_X would convert to two and one half (2.5) pounds of PM_{10}, given a 100% conversion. Mr. McGuire recognizes that the 100% conversion is not likely, but a 40% conversion (equivalent to a 1:1 ratio) is not unreasonable. Therefore, given his knowledge of the matter, he states that a 1:1 interpollutant ratio for SO_X and PM_{10} is an acceptable ratio. Based upon the above information, the District will accept Hanford LP's proposal and accept SO_X credits in place of PM_{10} credits at a 1:1 ratio.

To offset the remaining PM_{10} emissions (1st Qtr: 9,879 lbs; 2nd Qtr: 10,946 lbs; 3rd Qtr: 8,951; and 4th Qtr: 8,843 lbs), the facility has proposed to use ERC certificate C-255-5 and purchase the remaining credits from National Offsets. C-255-5 has available quarterly SO_X credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #C-255-5	6,000	7,000	5,800	5,400

With ERC Certificate C-255-5 and with the facility currently under option with National Offsets, the facility should have sufficient emission reduction credits to fully offset the PM_{10} emissions associated with this project.

SO_X Offset Calculations:

SO_X offsets are triggered by SO_X NSR Balance emissions in excess of 150 lb/day for the facility. As shown in Table 6, the NSR Balance for SO_X, after this project, is 260.6 lb/day, so offset requirements are triggered.

Prior to the current project being evaluated, the facility's NSR balance exceeded the offset threshold, and the facility offset the pre-project emissions during their previous permitting action. The amount of offsets required will only be the emissions increases associated with this project.

Offset = $IPE_{current\ project}$ * Offset Ratio

Where, $IPE_{current\ project}$ = Annual Increases in Permitted Emissions for the new emissions units (C-603-11-0 & -12-0)

$IPE_{current\ project}$ = 2,710 lb SO_X/year + 2,710 lb SO_X/year
= 5,420 lb SO_X/year

As discussed above, calculating the appropriate quarterly emissions to be offset is as follows:

$PE_{1st\ Qtr}$ = [(0.33 lb SO_X/event) ∗ (50 event/1st qtr) + 459.6 MMBtu/hr) ∗ (0.00071 lb/MMBtu) ∗ (2,000 hr/qtr)] + [(0.33 lb SO_Xevent) ∗ (50 event/1st qtr) + (459.6 MMBtu/hr) ∗ (0.00071 lb/MMBtu) ∗ (2,000 hr/qtr)]
= 1,338 lbs of SO_X

$PE_{2nd\ Qtr}$ = [(0.33 lb SO_X/event) ∗ (100 event/2nd qtr) + (459.6 MMBtu/hr) ∗ (0.00071 lb/MMBtu) ∗ (2,000 hr/qtr)] + [(0.33 lb SO_X/event) ∗ (100 event/2nd qtr) + (459.6 MMBtu/hr) ∗ (0.00071 lb/MMBtu) ∗ (2,000 hr/qtr)]
= 1,372 lbs of SO_X

$PE_{3rd\ Qtr}$ = [(0.33 lb SO_X/event) ∗ (100 event/3rd qtr) + (459.6 MMBtu/hr) ∗ (0.00071 lb/MMBtu) ∗ (2,000 hr/qtr)] + [(0.33 lb SO_X/event) ∗ (100 event/3rd qtr) + (459.6 MMBtu/hr) ∗ (0.00071 lb/MMBtu) ∗ (2,000 hr/qtr)]
= 1,372 lbs of SO_X

$PE_{4th\ Qtr}$ = [(0.33 lb SO_X/event) ∗ (50 event/4th qtr) + 459.6 MMBtu/hr) ∗ (0.00071 lb/MMBtu) ∗ (2,000 hr/qtr)] + [(0.33 lb SO_X/event) ∗ (50 event/4th qtr) + (459.6 MMBtu/hr) ∗ (0.00071 lb/MMBtu) ∗ (2,000 hr/qtr)]
= 1,338 lbs of SO_X

Assuming an offset ratio of 1.5: 1, the amount of SO_X ERC credits needed to be surrendered to the District is:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2,007	2,058	2,058	2,007

The applicant has stated that the facility plans to use ERC certificate C-392-5to offset the increases in SO_X emissions associated with this project. Certificate C-392-5 has available quarterly SO_X credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #C-392-5	2,500	2,500	2,500	2,500

With the above ERC certificate, the facility has sufficient offset credits, to offset increases in SO_X emissions.

F. Actual Emission Reductions

There are no actual emissions reductions (AERs) proposed as a result of this application. AER = 0.

G. Major Source/Title I Modification

1) A Major Source is defined in Section 3.19 of District Rule 2201 as a stationary source with the potential to emit 50 tons per year of NO_X or VOC, 100 tons per year of CO, or 70 tons per year of PM_{10} or SO_X. As shown in Table 6, pre-project daily CO emissions are 544 lbs/day. Therefore, the proposed Hanford Energy Park Peaker will cause the facility to exceed the major source threshold for CO and is therefore a new major source for this pollutant.

2) A Title I Modification is defined in Section 3.31 of District Rule 2201 as the modification of an existing non-major stationary source that increases its potential to emit to the levels specified in Section 3.19. This modification is considered a Title I modification since this project does create a new Title V facility for CO emissions.

H. Notification and Publication of Preliminary Decision

Per Rule 2201 Section 5.1.3.4.1, public notification is required for new major sources and Title I modifications. The facility will be a new major source for CO and this modification constitutes a Title I modification. Therefore, a new major source and Title I modification notice is required for CO emissions.

Per Rule 2201 Section 5.1.3.4.2, public notification is required for new and modified emission units with an increase in permitted emissions (IPE) greater than 100 lb/day of NO_X or VOC per emissions unit. As shown in the calculation section above, emissions for each GTE exceeds 100 lbs/day for NO_X emissions.

Per Rule 2201 Sections 5.1.3.4.3 through 5.1.3.4.5, public notification is required for new and modified sources with an IPE for those pollutants reaching the NSR balance notification thresholds for CO (attainment area), PM_{10}, or SO_X (550 lb CO/day, 70 lb PM_{10}/day or 140 lb SO_X/day). As shown in the calculation section above, the facility's NSR Balance does exceed the thresholds for CO, PM_{10}, and SO_X emissions, so public notification is triggered for CO, PM_{10}, and SO_X.

I. Daily Emissions Limitations

Daily emissions limitations (DELs) and other enforceable conditions are required by Rule 2201 Section 5.1.9.2 to reflect applicable emission limits including offset requirements. Per Rule 2201 Section 3.13.3, the DEL must be established pursuant to a permitting action occurring after the baseline date and used in calculation of the NSR balance or IPE.

The DELs for NO_X, CO, VOC, PM_{10}, and SO_X will consist of lb/hr emission limits and 24 hr/day of allowed operation.

VIII. Compliance

Rule 1080 Stack Monitoring:

This rule specifies that specific source types be equipped with CEMs. The proposed powerplant is not one of the listed source types.

Additionally, this rule specifies performance, data reduction, recordkeeping, and reporting criteria for continuous emission monitors. Because this facility will utilize CEMs, the provisions of this are applicable. These requirements will be incorporated in to the ATCs. Compliance is expected.

Rule 1081 Source Sampling:

Source testing of the new turbines will be required to demonstrate compliance with the PM10, NOx, CO, VOC, PM10, NH3, and fuel sulfur limits. Compliance with this rule is expected.

Rule 2010 Permits Required:

This rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By the submission of an ATC application, Handord LP is complying with the requirements of this rule.

Rule 2201 New and Modified Stationary Source Review Rule:

Section 4.1.1 requires BACT for a new or modified emissions unit if there is an increase in emissions in excess of 2 lb/day. As discussed in Sections VI.A and VII.D of this evaluation, BACT will be triggered for NO_X, VOC, PM_{10} and SO_X since there will be increases in permitted emissions greater than 2 lbs/day. And as demonstrated in Appendix C, BACT is satisfied for these pollutants.

Sections 4.2.2 and 4.2.3 require offsets for a new or modified stationary source with increases that exceed the established thresholds. As demonstrated in Sections VII.E.1 and VII.E.2 of this evaluation, the offset thresholds were exceeded for NO_X, CO, VOC, PM_{10}, and SO_X emissions, therefore offsets for those pollutants will be required for this project. However, as shown in Section VII.E.3, the increase in CO emissions is exempt from offsets per Rule 2201 section 4.2.1.1. As explained in Section VII.E.3 of this evaluation, the applicant has agreed to provide Emission Reduction Credits in order to offset the NO_X, VOC, PM_{10}, and SO_X emissions increases associated with this project.

Section 5.1.3.4.1 requires public notification for new major sources and Title I modifications. As discussed above, this project is a Title I modification, and this facility is a new major source for CO emissions, therefore public notification is required.

Section 5.1.3.4.2 requires public notification for new sources and modifications with increases in permitted emissions greater than 100 lb/day of NO_X, or VOC. Sections 5.1.3.4.3 and 5.1.3.4.4 require public notification if the NSR balance for CO, PM_{10}, or SO_X exceeds the stated level and there is an increase in permitted emissions. As shown in Sections VII.G & VII.H of this evaluation the thresholds are exceeded for NO_x, VOC, CO, SO_X, and PM_{10} and public notification is required.

Section 5.1.9.2 requires DELs to be included to reflect applicable emission limits. DELs are established by the turbine's emission limits as discussed in Section VII.I.

Therefore, compliance with this rule is expected.

Rule 2520 Federally Mandated Operating Permits:

This project will be subject to Rule 2520 (Title V) because it will meet the following criteria specified in section 2.0. Section 2.5 states "A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV (Acid Rain Program) of the CAA.

Pursuant to Rule 2520 section 5.3.1 Hanford LP must submit a Title V application within 12 months of commencing operations. No action is required at this time.

Rule 2540 Acid Rain Program:

The proposed turbines are subject to the acid rain program as phase II units, i.e. they will be installed after 11/15/90 and have a generator nameplate rating greater than 25 MW.

The acid rain program will be implemented through a Title V operating permit. Federal regulations require submission of an acid rain permit application at least 24 months before the later of 1/1/2000 or the date the unit expects to generate electricity. The facility will be required to submit an acid rain program application for the Hanford LP Power Project. The facility anticipates beginning commercial operation in September of 2001.

The acid rain program requirements for this facility are relatively minimal. Monitoring of the NO_X and SO_X emissions and a relatively small quantity of SO_X

allowances (from a national SO_X allowance bank) will be required as well as the use of a NO_X CEM.

Rule 4001 New Source Performance Standards Subpart GG:

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after 10/03/77. Therefore, this subpart applies to the new turbine installations.

NO_X Requirement §60.332(a):
Under the standard, NO_X emissions from the turbine with a minimum heat input rating of 250 MMBtu/hr are limited by the following equation:

NO_X (% by vol@ 15% O_2) 1 hr avg = 0.0075(14.4/Y)+ F

where: Y = manufacturers rated heat load (kJ/W-hr)
= (9,646 Btu/kW-hr)(kW/1000W)(1054.2 J/Btu)(kJ/1000J)[5]
= 10.16 kJ/W-hr (less than 14.4 kJ/W hour)

F = 0 (fuel bound nitrogen for natural gas fuel)

NO_X (% by vol@ 15% O_2) = 0.0075(14.4/10.16)+ 0
= 0.0106 %
= 106 ppmv @ 15% O2

Hanford LP is proposing a NO_X concentration limit of 3.7 ppmv @ 15% O_2 (3 hr average) as required by BACT. Therefore, compliance with the NSPS NO_X standard is expected.

SO_X Requirement §60.333(a) and (b):
Subpart GG also contains a SO_X standard, which limits fuel sulfur content to less than or equal to 150 ppmv SO_2 and 0.8% by weight. Hanford LP is proposing the use of natural gas fuel with a sulfur content of 0.25 gr/100 dscf, which is less than 0.46 ppmv (see Rule 4801 compliance discussion). Thus, compliance with the SO_X standard is also expected.

Source Testing and Monitoring Requirements (60.334 & 60.335):
§60.334(a) requires the owner/operator of any stationary gas turbine using water injection to control NO_X to install and operate a continuous emissions monitoring system (CEM) to monitor and record fuel consumption and ratio to water to fuel fired. The turbines are not equipped with water injection.

[5] The rated heat load for the GE LM6000 is 9,646 Btu/kW-hr, per Hanford LP.

§60.334(b) requires monitoring of sulfur content and nitrogen content of the fuel being fired in the turbine. In determining the sulfur and nitrogen content of the fuel, §60.335(e) allows the analysis to be performed by the owner/operator, service contractor, fuel vendor, or any other qualified agency. The turbines shall be fired on natural gas as limited by permit condition. Fuel sulfur content sampling and analysis will be required annually. Compliance with this rule is expected.

Rule 4101 Visible Emissions:

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity). The visible emissions limit is not expected to be exceeded based on similar operations and the fact that the turbines are fired solely on PUC quality natural gas. Therefore, compliance with this rule is expected.

Rule 4102 Nuisance:

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained as required by permit conditions. Therefore, compliance with this rule is expected.

A Health Risk Assessment (HRA) is required for any increase in hourly or annual emissions of hazardous air pollutants (HAPs). HAPs are limited to substances included on the list in CH&SC 44321 and that have an OEHHA approved health risk value. The installation of the new gas turbine engines results in increases in emissions of HAPs.

The risk from this project was reviewed by performing a prioritization in accordance with the requirements of the CAPCOA prioritization guidelines. The resulting prioritization score from this project is 16.75. Pursuant to the District Risk Management Policy for New and Modified Sources, a Health Risk Assessment (HRA) is required for projects with prioritization scores of one or greater. BACT for toxic emission control (T-BACT) is not required for this project because the HRA indicates that the risk is not above the District acute, chronic, and cancer risk thresholds for triggering T-BACT requirements and no further risk analysis is required. Therefore, compliance with this rule is expected.

Rule 4201 Particulate Matter Concentration:

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot. Particulate matter emissions are not expected to exceed 0.1 grain per cubic foot of gas at dry standard conditions with the use of natural gas.

$$PM\ Conc.\ (gr/scf) = \frac{(PM\ emission\ rate) \times (7000\ gr/lb)}{(Air\ flow\ rate) \times (60 min/hr)}$$

For the GTEs:
PM_{10} emission rate = 3.03 lb/hr. Assuming 100% of PM is PM_{10}

PM Conc. (gr/scf)=[(3.03 lb/hr) ∗ (7000 gr/lb)] ÷ [(599,785 ft^3/min) ∗ (60 min/hr)]
PM Conc. = 0.00059 gr/scf

Calculated emissions are well below the allowable emissions level. It can be assumed that emissions will not exceed the allowable 0.1 gr/scf. Therefore, compliance with Rule 4201 is expected.

Rule 4703 - Stationary Gas Turbines:

Rule 4703 is applicable to stationary gas turbines with a rating greater than 0.3 megawatts. The facility proposes to install two 47.5 MW gas turbines, therefore this rule applies.

Section 5.1.1 of this rule limits the NO_X emissions from stationary gas turbine systems greater than 10 MW, and equipped with Selective Catalytic Reduction (SCR), based on the following equation:

When fired on natural gas: NO_X (ppmv @ 15% O_2) = 9 ∗ EFF/25

where: EFF = Efficiency (%)
= [3,412 Btu/kW-hr/Actual Heat @ HHV)] ∗ 100

The Actual Heat @ HHV for the GE LM6000 turbine is 9,646 Btu/kW-hr as reported by Hanford LP:

EFF = (3,412/9,646) ∗ 100
= 35.37%

When gas fired: NO_X = 9 ∗ 35.37/25
= 12.7 ppmv @ 15% O2

The proposed turbines will be limited to a maximum of 3.7 ppmv NO_X @ 15% O_2 (based on a 3-hour average), therefore compliance is expected.

Section 5.2 limits the CO emissions from stationary gas turbine systems subject to Section 5.1.1 to 200 ppmv CO @ 15% O_2. The proposed turbines will be limited to a maximum of 6 ppmv CO @ 15% O_2, therefore compliance is expected.

Sections 6.2 and 6.3 contain the following monitoring, recordkeeping and source testing requirements. These requirements will be included as permit conditions.

- 6.2.1 Install, operate, and maintain equipment that continuously measures elapsed time of operation and exhaust gas NO_X emissions
- 6.2.1.1 Monitor control system operating parameters.
- 6.2.2 Maintain records for inspection at any time for a period of two years.
- 6.2.3 Correlate control system operating parameters with NO_X emissions. This information may be used by the APCO to determine compliance when the continuous emissions monitoring system not operating properly.
- 6.2.4 Maintain an operating log that includes, on a daily basis, the actual local start-up and stop time, length and reason for reduced load periods, total hours of operation, type and quantity of fuel used (liquid/gas).
- 6.3 Provide source test information annually regarding the exhaust gas NO_X and CO concentrations.

Therefore, compliance with Rule 4703 is expected.

Rule 4801 Sulfur Compounds:

A person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2 % by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes:

The sulfur of the natural gas fuel is 0.25 gr/100 dscf.

The F factor is 8,710 dscf/MMBtu.

The ratio of the volume of the SO_x exhaust to the entire exhaust for one MMBtu of fuel combusted is:

Volume of SO_x: $V = \frac{n \cdot R \cdot T}{P}$

Where:

- n = number of moles of SO_x produced per MMBtu of fuel.

- Weight of SO_x as SO_2 is 64 lb/(lb-mol)
- $n = \frac{0.00071 lb}{MMBtu} \times \frac{1(lb-mol)}{64 lb} = 0.000011(lb-mol)$
- $R = \frac{0.7302 ft^3 \cdot atm}{(lb-mol)°R}$
- T = 500 °R
- P = 1 atm

Thus, volume of SO_X per MMBtu is:

$$V = \frac{n \cdot R \cdot T}{P}$$

$$V = \frac{0.000011(lb-mol) \cdot \frac{0.7302 ft^3 \cdot atm}{(lb-mol)°R} \cdot 500°R}{1 atm}$$

$$V = 0.004 ft^3$$

Since the total volume of exhaust per MMBtu is 8,710 scf, the ratio of SO_X volume to exhaust volume is

$$= \frac{0.0011}{8,710} = 0.00000046 = 0.46\, ppmv = 0.000046\%\, by\, volume$$

0.000046 % < 0.05 %, therefore the gas turbine engines are expected to comply with Rule 4801.

California Environmental Quality Act (CEQA):

The California Energy Commission (CEC) is the lead Agency for CEQA. A change to the land use (zoning) is required for the proposed project. The District cannot make its final decision on these ATCs until CEQA has been satisfied.

IX. Recommendation

Issue ATCs. See draft ATCs in Appendix A.

X. Billing Information

Fee Schedule 8 – Electric Generation Schedule, is applicable to the proposed equipment.

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
C-603-11-0	3020-8B-G	47,500 kW	$8,757.00
C-603-12-0	3020-8B-G	47,500 kW	$8,757.00

APPENDIX A

DRAFT AUTHORITIES TO CONSTRUCT

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: C-603-12-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: HANFORD L P
MAILING ADDRESS: ATTN: MARK KEHOE
4300 RAILROAD AVENUE
PITTSBURG, CA 94565

LOCATION: 10596 IDAHO AVE
HANFORD, CA 93230

EQUIPMENT DESCRIPTION:
47.5 MW GENERAL ELECTRIC MODEL LM6000 SPRINT NATURAL GAS FIRED GAS TURBINE ENGINE/GENERATOR WITH WATER SPRAY PREMIXED COMBUSTION SYSTEM, SERVED BY SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND OXIDATION CATALYST.

CONDITIONS

1. This Authority to Construct may be revised at the conclusion of the 30-day public comment period required by District Rule 2201 to incorporate responses to timely comments received by the District. [District Rule 2201]
2. The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]
3. Upon implementation of C-603-11-0 and '-12-0, emission offsets shall be provided to offset emissions increases in the following amounts: PM10 - Q1: 12,436 lb, Q2: 12,740 lb, Q3: 12,740 lb, and Q4: 12,436 lb; SOx (as SO2) - Q1: 1,338 lb, Q2: 1,372 lb, Q3: 1,372 lb, and Q4: 1,338 lb; NOx (as NO2) - Q1: 25,772 lb, Q2: 26,542 lb, Q3: 26,542 lb, and Q4: 25,772 lb; and VOC - Q1: 4,848 lb, Q2: 4,916 lb, Q3: 4,916 lb, and Q4: 4,848 lb. Offsets shall be provided at the appropriate offset ratio specified in Rule 2201 Section 4.2.4. [District Rule 2201]
4. At least 30 days prior to commencement of construction, the permittee shall provide the District with written documentation that all necessary offsets have been acquired or that binding contracts to secure such offsets have been entered into. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. **YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 WHEN CONSTRUCTION OF THE EQUIPMENT IS COMPLETED.** Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

DAVID L. CROW, Executive Director / APCO

DRAFT

SEYED SADREDIN, Director of Permit Services

C-603-12-0 : Apr 19 2001 11:44AM – SHEIKHS : Joint Inspection Required With SHEIKHS

5 Selective catalytic reduction (SCR) system and oxidation catalyst shall serve the gas turbine engine. Exhaust ducting shall be equipped with a fresh air inlet and blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. Permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

6. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

7. {118} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

8. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

9. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

10. Gas turbine engine shall be equipped with an air inlet cooler/filter and lube oil vent coalescer. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater except for up to three minutes in any hour. [District Rule 2201]

11. Gas turbine engine shall be equipped with continuous monitoring system to measure and record hours of operation and fuel consumption. [District Rules 2201, 4001, and 4703]

12. Operation of the turbine shall not exceed 8,000 hours per calendar year. [District Rule]

13. Gas turbine engine shall be equipped with continuous emission monitor for NOx (before and after SCR system), CO, and O2. Continuous emission monitor shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as normal operating conditions. [District Rules 2201, 4001, and 4703]

The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. [District Rule 1081]

15. Gas turbine engine shall be fired exclusively on natural gas with a sulfur content no greater than 0.25 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

16. Emission rates from gas turbine engine, excluding startup and shutdown, shall not exceed any of the following: PM10: 3.03 lb/hr, SOx (as SO2): 0.33 lb/hr, NOx (as NO2): 3.7 ppmvd @ 15% O2 and 6.3 lb/hr, VOC (as methane): 2.0 ppmvd @ 15% O2 and 1.19 lb/hr , CO: 6.0 ppmvd @ 15% O2 and 6.2 lb/hr, or ammonia (NH3): 10 ppmvd @ 15% O2. All emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

17. Compliance with ammonia slip limit shall be demonstrated by using the following calculation procedure: ammonia slip ppmv @ 15% O2 = ((a-(bxc/1,000,000)) x 1,000,000/b), where a = ammonia injection rate (lb/hr)/17 (lb/lb mol), b = dry exhaust gas flow rate (lb/hr)/29 (lb/lb. mol), and c = change in measured NOx concentration ppmv at 15% O2 across catalyst. [District Rule 4102]

18. Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr and ppmvd emission limits in condition #13. Shutdown is defined as the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup and shutdown of gas turbine engine shall not exceed a time period of one hour each per occurrence. [District Rule 2201]

19. Startup and shutdown events shall not exceed 300 occurences per calendar year and once per day. [District Rule]

20. During startup or shutdown of any gas turbine engine, combined emissions from the two gas turbine engines (C-603-11 and '-12) shall not exceed the following: NOx - 15.4 lb and CO - 15.4 lb in any one hour. [California Environmental Quality Act]

21. Maximum daily emissions from gas turbine engine shall not exceed any of the following: PM10 - 72.8 lb/day; SOx (as SO2) - 7.8 lb/day; NOx (as NO2) - 151.5 lb/day; VOC - 28.7 lb/day; and CO - 150.3 lb/day. [District Rule 2201]

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CONDITIONS CONTINUE ON NEXT PAGE

22. Compliance testing to demonstrate compliance with the PM10, NOx (as NO2), VOC, CO, and ammonia emission limits, and fuel gas sulfur content shall be conducted within 60 days of initial operation and at least once every twelve months thereafter. [District Rule 1081]

23. Compliance demonstration (source testing) shall be by District witnessed, or authorized, sample collection by ARB certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

24. The following test methods shall be used PM10: EPA method 5 (front half and back half), NOx: EPA Method 7E or 20, CO: EPA method 10 or 10B, O2: EPA Method 3, 3A, or 20, VOC: EPA method 18 or 25, ammonia: BAAQMD ST-1B, and fuel gas sulfur content: ASTM D3246. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081, 4001, and 4703]

25. The permittee shall notify the District of the date of initiation of construction no later than 30 days after such date, the date of anticipated startup not more than 60 days nor less than 30 days prior to such date, and the date of actual startup within 15 days after such date. [District Rule 4001]

26. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

27. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

29. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

30. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

31. The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

32. All records required to be maintained by this permit shall be maintained for a period of two years and shall be made readily available for District inspection upon request. [District Rule 2201]

33. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program. [District Rule 2540]

DRAFT

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: C-603-11-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: HANFORD L P

MAILING ADDRESS: ATTN: MARK KEHOE
4300 RAILROAD AVENUE
PITTSBURG, CA 94565

LOCATION: 10596 IDAHO AVE
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EQUIPMENT DESCRIPTION:
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CONDITIONS CONTINUE ON NEXT PAGE

DAVID L. CROW, Executive Director / APCO

DRAFT

SEYED SADREDIN, Director of Permit Services

C-603-11-0 : Apr 19 2001 11:42AM -- SHEIKHS : Joint Inspection Required With SHEIKHS

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CONDITIONS CONTINUE ON NEXT PAGE

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28. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

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31. The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

32. All records required to be maintained by this permit shall be maintained for a period of two years and shall be made readily available for District inspection upon request. [District Rule 2201]

33. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program. [District Rule 2540]

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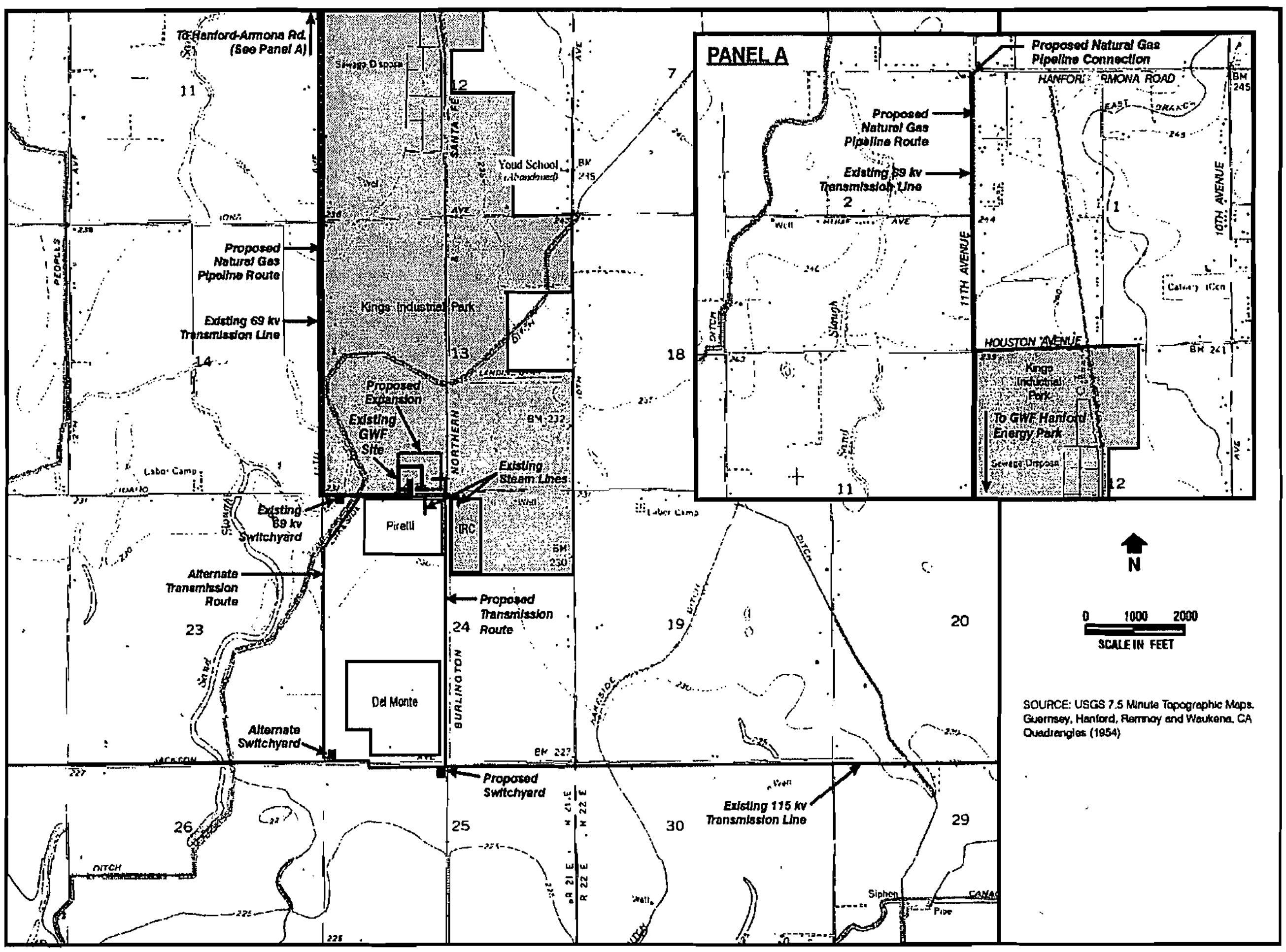
APPENDIX B

PLOT PLAN

Figure 1 - Peaker Unit Location



Mark/wps/Hanford/peaker/ATCappsup0301.
4/2/01

APPENDIX C

BACT DETERMINATION

TOP-DOWN BACT ANALYSIS

TOP-DOWN BACT ANALYSIS
FOR REVISING EXISTING BACT DETERMINATION

Facility Name:	Hanford LP
Mailing Address:	4300 Railroad Avenue Pittsburg, CA 94565-6006
Contacts:	Doug Wheeler, Vice President (925) 431-1443
	Mark Kehoe, Director – Environmental and Safety Programs (925) 431-1440
Application #s:	C-603-11-0 and –12-0
Project #:	1010451
Application Received:	04/09/01
Deemed Complete:	04/12/01
Reviewing Engineer:	Samir Sheikh
Date:	04/18/01
Lead Engineer:	Joven Refuerzo

I. PROPOSAL:

The applicant has requested Authority to Construct permits for the installation of two 47.5 MW General Electric LM6000 PC Sprint natural gas-fired Gas Turbine Engines (GTEs) with water-spray premixed combustion systems, Selective Catalytic Reduction (SCR) systems, and CO & VOC catalysts. The turbines will be installed in a simple cycle configuration (no heat recovery), will be served by NO_X Continuous Emissions Monitoring Systems (CEMS) and will be utilized to generate electric power for a 95.0 MW power plant.

II. PROCESS DESCRIPTION:

Hanford LP proposes to operate a 95.0 MW power plant located adjacent to the existing GWF Hanford Cogeneration plant. The simple-cycle gas turbines firing only natural gas will be used to provide power to California's electricity grid during periods of high electricity demand.

The Hanford Energy Park Peaker (HEPP) will be a nominal 95 MW (gross) natural gas-fired simple cycle gas turbine power plant (consisting of two gas turbine/generators), with a 1.2 mile 115-kV transmission line with an interconnection to the existing Pacific Gas and Electric Company (PG&E) 115-kV Henrietta-Kingsburg transmission line at the corner of 11th Avenue and Jackson Avenue to the south. The dual circuit 115-kV line will be supported on single poles that will leave the plant west along Idaho and turn south on 11th Avenue to Jackson Avenue.

Natural gas for the HEPP will be delivered via a 16" gas line being installed by So-Cal Gas Company from their gas distribution system 2.8 miles northwest of the HEPP at the intersection of 11th Avenue and Hanford-Armona Road. The gas line will follow an easement on 11th Avenue south to Idaho Avenue before turning east toward the plant.

Domestic water will be supplied from the Hanford municipal water system and will be used for industrial purposes. Groundwater from on-site water well at the adjacent Hanford Cogeneration Plant will supply process-cooling water for the gas turbine inlet and NOx control (during first year of operation). The dual Combustion Turbine/Generator (CTG) unit will use 140 gpm of process water that has been demineralized by a combination water demineralizer and reverse osmosis water treatment unit located at the Hanford Cogeneration facility. Approximately 20 gpm of lowdown from the CTF units will be diverted to the existing cooling tower for the cogen facility.

III. EQUIPMENT LISTING:

C-603-11-0: 47.5 MW General Electric Model LM6000 natural gas fired Gas Turbine Engine (GTE) with water-spray premixed combustion system, served by selective catalytic reduction (SCR) system and oxidation catalyst.

C-603-12-0: 47.5 MW General Electric Model LM6000 natural gas fired Gas Turbine Engine (GTE) with water-spray premixed combustion system, served by selective catalytic reduction (SCR) system and oxidation catalyst.

VI. EMISSION CONTROL TECHNOLOGY EVALUATION

Best Available Control Technology (BACT):

A. Applicability

Per Rule 2201 Sections 4.1.1 and 4.1.1.1, BACT shall be applied to a new or modified emissions unit if the new unit or modification results in an increase in permitted emissions (BACT IPE) greater than 2 lb/day for NO_X, CO (non-attainment area), VOC, PM_{10}, or SO_X. In a CO attainment area, the CO NSR balance must also exceed 550 lb/day to trigger BACT.

As seen in Section VII of the engineering evaluation, and summarized in the table below, the applicant is proposing to install two new emissions units with BACT IPEs greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, CO, VOC, PM_{10}, and SO_X criteria pollutants since there are IPEs greater than 2 lbs/day and the CO NSR Balance is greater than 550 lbs/day.

	PM_{10}	SO_X	NO_X	VOC	CO
C-603-11-0 (lb/day)	73.2	7.0	151.2	16.8	184.8
C-603-12-0 (lb/day)	73.2	7.0	151.2	16.8	184.8
BACT required ?	Y	Y	Y	Y	Y

B. BACT Policy

Per District Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule. The District BACT Clearinghouse recently included a new BACT Guideline applicable to these turbine installations [Simple Cycle Gas Fired Turbines less than 50 MW, Powering an Electrical Generation Operation]. (See Appendix I) However, the new BACT guideline did not address Best Available Control Technology for CO emissions since BACT was not triggered for that specific project. Therefore, this BACT Analysis will **revise** the new BACT guideline to include BACT for CO emissions.

C. Achieved in Practice Determination

The District conducted research throughout the State of California to determine whether or not there has been a control technology that has been established for this class and category of source [Simple Cycle Gas Fired Turbine < 50 MW]. The San Joaquin Valley APCD and other Air Districts were surveyed to determine if there were existing simple cycle gas turbines rated less than or equal to 50 MW powering electrical generation operations.

Within the SJVAPCD, there were many turbine installations that were identified that were rated less than 50 MW, but all of those installations were cogeneration operations and utilized heat recovery. Therefore, they will not be considered for this BACT determination. However, there were two existing facilities located that operate simple cycle gas turbines of the proper size and operating schedule. The first facility, Northern California Power Agency N-583, operates a 25.24 MW General Electric Frame 5 dual fired combustion turbine generator (Appendix II). The second facility, Turlock Irrigation District N-2246, operates two 25.8 MW General Electric Frame 5 dual fired combustion turbine generators (Appendix II). All three turbine installations are permitted with operating schedules of less than 877 hours per year, and have permitted CO emissions of 0.0677 lb CO/MMBtu and 200 ppmv CO @ 15% O_2 (0.4484 lb/MMBtu), respectively. The simple cycle turbines covered by this BACT guideline may operate full time and in the interest of finding more accurate information for this source category, further research was conducted.

Within other Air Districts, the District was able to locate only a few facilities that operated simple cycle turbine installations. Based on the research conducted, two existing facilities were located within the Sacramento Metropolitan Air Quality Management District (SMAQMD) and one proposed facility was located within the Bay Area Air Quality Management District (BAAQMD). The two facilities located within the SMAQMD were the Carson Energy facility and the Sacramento Cogeneration Authority (Proctor & Gamble) facility, and the one facility located in the BAAQMD was the United Golden Gate Power Plant (UGGPP) facility. The Carson Energy facility operates a 42 MW GE LM6000 turbine equipped with water injection and a Selective Catalytic Reduction (SCR) system, and is permitted with CO emissions of 6 ppmv. The Proctor and Gamble facility also operates a 42 MW GE LM6000 turbine equipped with water injection and a Selective Catalytic Reduction (SCR) system, and is permitted with CO emissions of 6 ppmv. The UGGPP facility operates a 48 MW GE LM6000 turbine equipped with water injection and a Selective Catalytic Reduction (SCR) system, and is permitted with NO_X emissions of 3 ppmv.

The District's BACT Guideline policy states that, when determining a control technology as achieved-in-practice, the rating and capacity for the unit where the control was achieved must be approximately the same as that for the proposed unit. According to Brian Krebs of the Sacramento Metro Air Quality Management District (SMAQMD), the Carson Energy turbine and the Proctor & Gamble turbine have been permitted to operate 4,650 and 4,380 hours per year, respectively. And according to the Preliminary Determination of Compliance (PDOC) engineering evaluation for the UGGPP facility, UGGPP requested an operating schedule of 4,000 hours per year to be placed upon their Permit to Operate.

With the information discussed above, the District will utilize the guidance set forth by the California Air Resources Board's September 1999 <u>Guidance for Power Plant Siting and Best Available Control Technology</u> document (Table III-1) (Appendix III) and deem achieved in practice as the following: 6 ppmv CO @ 15% O_2 for CO emissions.

D. Top-Down Best Available Control Technology (BACT) Analysis for Permit Units C-603-11-0 and -12-0 (47.5 MW Gas Turbine Engines):

BACT Analysis for CO Emissions:

According to BACT guidelines for controlling CO emissions, e.g. Guidelines 3.4.1, 3.4.2, 3.4.3, 3.4.4 & 3.4.5, California Air Resources Board's <u>Guidance for Power Plant Siting and Best Available Control Technology</u>, South Coast AQMD guidelines, and Bay Area AQMD Guidelines; the following are possible controls for NO_X emissions from similar operations.

Step 1 - <u>Identify All Possible Control Technologies</u>

CO emissions result from the combustion of natural gas.

General control for CO emissions include the following options:

1. $SCONO_X$™: employs a precious metal catalyst and a NO_X absorption/regeneration process step to convert CO and NO_X into CO_2, H_2O, and N_2. The principle advantage of the $SCONO_X$™ technology over SCR is the

elimination of ammonia emissions and the simultaneous reduction of CO, VOC, and NO_X. $SCONO_X$™ has a maximum operating temperature of ≈ 700 °F

2. Catalytic Combustors (Xonon™ technologies): are flameless processes that allow fuel oxidation to take place at temperatures well below the normal lean flammability limits of the air-fuel mixture. For this reason, the use of catalysts in gas turbine combustion to replace part of the thermal reaction zone allows stable combustion to occur at peak temperatures that are as much as 1,800 °F lower than those of conventional combustors.

3. Oxidation Catalysts: utilizes the use of a catalyst bed (platinum based) at elevated temperatures in the range of 500-900 degree F in the exhaust stack to create an intermediate chemical reaction to disassociate the CO & VOC molecules and reduce the CO & VOC emissions.

4. PUC quality natural gas. A CO concentration of 0.4484 lb/MMBtu. (Industry Standard)

CO Emissions Control Technologies

a. $SCONO_X$
b. Catalytic Combustors – Xonon Technologies
c. CO/VOC Oxidation Catalysts
d. PUC quality natural gas. A CO concentration of 0.4484 lb/MMBtu

Step 2 - <u>Eliminate Technologically Infeasible Options</u>

The Xonon™ catalytic combustors are considered technologically infeasible for this installation because the combustors are not commercially available for any turbine type at this time, according to Chuck Solt, regulatory affairs director of Catalytica Combustion Systems. Only since October of 1998 has this Xonon technology been placed on a turbine installation. Genxon Power Systems installed a 1.55 MW natural gas fired Kawasaki MIA-13A combustion gas turbine to produce electricity for the city of Santa Clara. To date, this has been the only installation that is equipped with the Xonon technology, and the technology has not been applied to larger sized turbine installations. The Xonon system has been performing as designed, providing 2.5 ppmv NO_X emissions from the turbine for over 7,400 hours of operation, but this is the only turbine manufacturer that has had an industry installation. Hanford LP could install Kawasaki turbines at their facility, but to provide the amount of energy needed by the power plant (95 MW), they would have to install 62 turbines, instead of the two turbines they have proposed. Since two Kawasaki turbines are not large enough to supply the power output needed by Hanford LP, the District will not require the installation of extra turbines in order to utilize a specific control technology.

All remaining control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

In order to determine the control efficiency of a given control method, the industry standard must first be determined. The industry standard is typically established as the industry wide average baseline emission rate for the device in question.

As indicated in the achieved in practice discussion above, the simple cycle turbine installations for the two existing facilities within the District (N-583 and N-2246) were permitted at 0.0677 lb CO/MMBtu and 200 ppmv CO @ 15% O_2 (0.4484 lb/MMBtu), respectively. Carson Energy, Sacramento Cogeneration Authority (Proctor & Gamble), and United Golden Gate Power Plant (UGGPP) are relatively new facilities and will therefore not be considered for the industry-wide average baseline emission rate. Rule 4703 requires CO emissions of 200 ppmv CO @ 15% O_2 (0.4484 lb/MMBtu) (see Appendix IV) and an existing facility is currently permitted under this limit, therefore the District will consider 200 ppmv CO @ 15% O_2 (0.4484 lb/MMBtu) as industry standard for this class and category of source.

Therefore, the proposed emissions from the gas turbines using industry standard values can be calculated as:

CO (annual):

$$\frac{0.4484\ \text{lb}}{\text{MMBtu}} \times \frac{459.6\ \text{MMBtu}}{\text{hr}} \times \frac{8{,}000\ \text{hr}}{\text{year}} = 1{,}648{,}677\ \text{lb CO/year}$$

PE_{CO} = 1,648,677 lb CO/year = 824.3 tons CO/year

The District will assume a 90% CO control efficiency for the installation of a $SCONO_X$ system.[1] The industry standard turbine CO emissions using a $SCONO_X$ system is:

CO (annual):

$$\frac{1{,}648{,}677\ \text{lb CO}}{\text{year}} \times \frac{(1-90\%)}{1}$$

PE_{CO} = 164,868 lb CO/year = 82.4 tons CO/year

The District will assume a 90% CO control efficiency for the installation of a CO catalyst (as stated in Project C-1010376). The industry standard turbine CO emissions using a CO catalyst system is:

[1] Per Richard Davis, GLET Representative, the control efficiencies for CO and VOC emissions are "greater than 90%." The District will assume a 90% control efficiency to remain conservative.

CO (annual):

$$\frac{1{,}648{,}677 \text{ lb CO}}{\text{year}} \bigg| \frac{(1-90\%)}{1}$$

PE_{CO} = *164,868 lb CO/year = 82.4 tons CO/year*

Control Method	Industry Standard Emissions		Controlled Emissions		Overall Control efficiency
	lb/year	ton/year	lb/year	ton/year	
a. $SCONO_X$ System	1,648,677	824.3	164,868	82.4	90%
b. CO/VOC Oxidation Catalyst	1,648,677	824.3	164,868	82.4	90%
c. Natural gas	1,648,677	824.3	1,648,677	824.3	0%

CO Emission Control Technology Rankings

Rank	Control Efficiency
#1. $SCONO_X$ System	90%
#2. CO/VOC Oxidation Catalyst	90%
#3. Natural gas	0%

Step 4 - <u>Cost Effectiveness Analysis</u>

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

District Policy establishes annual cost thresholds for imposed control based upon the amount of pollutants abated by the controls. If the cost of control is at or below the threshold, it is considered a cost effective control. If the cost exceeds the threshold, it is not cost effective and the control is not required. Per District BACT Policy, the maximum cost limit for CO reduction is \$300 per ton of CO reduced.

1. CO Cost Effectiveness Analysis:
$SCONO_X$ Systems (by Goal Line Environmental Technologies)

The District conducted research during Project C-1010207 attempting to first to determine whether the control technology would be feasible for this type of installation, because the outlet temperature of the turbine exhaust was at approximately 700 °F. Published throughout the company's website it stated that the ideal operating parameters for the $SCONO_X$ system was between 300 °F to 700 °F, and therefore raised the question on whether or not the $SCONO_X$ system would operate properly for this simple cycle installation. On a recent BACT analysis, the District was able to contact a Mr. Greg Gilbert of Goal Line Environmental Technologies (GLET) from the company's Sacramento office and briefly discuss with him the scope of the turbine installation project for a similar simple cycle turbine installation. Based upon that conversation, Mr. Gilbert stated that a facility would be able to install $SCONO_X$ on a simple cycle installation, with the use of exhaust cooling technologies. Therefore, the control technology is feasible for this installation.

The District conducted more research to determine the appropriate cost information regarding the $SCONO_X$ control technology. Based upon research conducted in Project C-1010207, Mr. Gilbert was able to give the District an approximate cost for the installation of a $SCONO_X$ system to a 50 MW gas turbine. He stated that the cost to install a $SCONO_X$ system (including the exhaust cooling devices) would be approximately \$4.0 - \$4.5 million. To remain conservative, the District assumed the lower cost of \$4.0 million dollars as the true installation cost.

Description of Cost	Cost Factor	Cost	Source
Direct Capital Costs (DC):			
Purchase Equipment Costs (PE):			
(A) Basic Equipment: $SCONO_X$ System		4,000,000	**GoalLine**
(B) Instrumentation: included in base price		0	**OAQPS**
Taxes and Freight:	0.08 A*B	320,000	**OAQPS**
PE Total:		4,320,000	
Direct Installation Costs (DI): Assume Modular SCR w/ simple installation			
Foundation and Supports:	0.08 PE	345,600	**OAQPS**
Handling and Erection:	0.14 PE	604,800	**OAQPS**
Electrical:	0.04 PE	172,800	**OAQPS**
Piping:	0.02 PE	86,400	**OAQPS**
Insulation:	0.01 PE	43,200	**OAQPS**
Painting:	0.01 PE	43,200	**OAQPS**
DI Total:		1,296,000	
Site Preparation and Buildings			
DC Total = PE + DI:		5,616,000	
Indirect Costs (IC):			
Engineering:	0.10 PE	432,000	**OAQPS**
Construction and Field Expenses:	0.05 PE	216,000	**OAQPS**
Contractor Fees:	0.10 PE	432,000	**OAQPS**
Start-up:	0.02 PE	86,400	**OAQPS**
Performance Testing:	0.01 PE	43,200	**OAQPS**
Contingencies:	0.03 PE	129,600	**OAQPS**
IC Total:		1,339,200	
Total Capital Investments (TCI = DC + IC):		6,955,200	
Direct Annual Costs (DAC): Assume $SCONO_X$ requires 0.5 hrs/shift			
Operating Costs (O): 3 shifts per 24 hr/day, 8,000 hours/year (≈ 1,095 shifts/year)			
Operator: 0.50 hr/shift	\$25/hr	13,687	**OAQPS**
Supervisor:	15% operator	2,053	**OAQPS**
Maintenance Costs (M):			

Labor: 0.5 hr/shift	$25/hr	13,687	**OAQPS**
Material:	100% labor	13,687	**OAQPS**
Utility Costs (U):			
Performance loss:	0.5%		
Electricity Cost:	$0.06/kWh	118,320	**Variable per GoalLine**
Catalyst Replace:		374,054[2]	**GoalLine**
Catalyst Washing:	Variable	36,000	**GoalLine**
Catalyst Dispose: (Precious Metal Recovery = 1/3 replace cost)		-124,685	**GoalLine**
H_2 carrier stream: 93 lb steam/hr/MW (@ $0.006/lb)	Variable	240,982	**GoalLine**
H_2 reforming: 14 ft^3 CH_4/hr/MW (@ $0.00388/$ft^3$)	Variable	23,459	**GoalLine**
Total DAC:		711244	
Indirect Annual Costs (IAC):			
Overhead:	60% O & M	25,868	**OAQPS**
Administrative:	0.02 TCI	139,104	**OAQPS**
Insurance:	0.01 TCI	69,552	**OAQPS**
Property Tax:	0.01 TCI	69,552	**OAQPS**
Annualized Total Capital Investment: interest rate (%) 10 Period (years): 10	0.1627 TCI	1,131,611	**District Policy**
Total IAC:		1,015,320	
Total Annual Cost (DAC + IAC):		**2,146,931**	

District BACT policy requires the use of a Multi-Pollutant Cost Effectiveness Threshold (MCET) for a BACT option controlling more than one pollutant. The installation of a $SCONO_X$ system will control NO_X, CO, and VOC emissions. The MCET is calculated as follows:

$$MCET (\$/yr) = (E_{NOx} \times T_{NOx}) + (E_{VOC} \times T_{VOC}) + (E_{CO} \times T_{CO})$$

Where: E_{NOx} = tons-NO_X controlled/yr
E_{VOC} = tons-VOC controlled/yr
E_{CO} = tons-CO controlled/yr
T_{NOx} = District's cost effectiveness threshold for NO_X
= $9,700/ton-$NO_X$
T_{VOC} = District's cost effectiveness threshold for VOCs
= $5,000/ton-VOCs
T_{CO} = District's cost effectiveness threshold for CO
= $300 /ton-CO

To determine E_{NOx} and E_{VOC}, the District has to establish what Industry Standard is for NO_x and VOC emissions. As shown in Project C-1010207, the industry

[2] See Appendix V

standards for NO_x and VOC were set at 25 ppmv @ 15% O_2 and 6.25 ppmv @ 15%O_2, respectively.

Therefore, the proposed emissions from the gas turbines using industry standard values can be calculated as:

<u>VOC (annual):</u>

$$\frac{0.0008\ \text{lb}}{\text{MMBtu}} \left| \frac{459.6\ \text{MMBtu}}{\text{hr}} \right| \frac{8{,}000\ \text{hr}}{\text{year}} = 29{,}414\ \text{lb VOC/year}$$

PE_{VOC} = 29,414 lb VOC/year = 14.7 tons VOC/year

NO_x <u>(annual):</u>

$$\frac{0.0332\ \text{lb}}{\text{MMBtu}} \left| \frac{459.6\ \text{MMBtu}}{\text{hr}} \right| \frac{8{,}000\ \text{hr}}{\text{year}} = 122{,}070\ \text{lb } NO_x\text{/year}$$

PE_{NOx} = 122,070 lb NOx/year = 61 tons NO_x*/year*

The District will assume a 90% VOC control efficiency for the installation of a $SCONO_X$ system.[3] The industry standard turbine VOC emissions using a $SCONO_X$ system is:

<u>VOC (annual):</u>

$$\frac{29{,}414\ \text{lb VOC}}{\text{year}} \left| \frac{(1 - 90\%)}{1} \right. = 2{,}941\ \text{lb VOC/year}$$

PE_{VOC} = 2,941 lb VOC/year = 1.5 tons VOC/year

The proposed annual emissions from a gas turbine equipped the $SCONO_X$ control technology with NO_X emissions of 2.5 ppmv @ 15% O_2 (0.0092 lb/MMBtu) can be calculated as:

<u>NO_X (annual):</u>

$$\frac{0.0092\ \text{lb}}{\cancel{\text{MMBtu}}} \left| \frac{459.6\ \cancel{\text{MMBtu}}}{\cancel{\text{hr}}} \right| \frac{8{,}000\ \cancel{\text{hr}}}{\text{year}} = 33{,}827\ \text{lb } NO_X\text{/year}$$

PE_{NOx} = 33,827 lb NOx/year = 16.9 tons NOx/year

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[3] Per Richard Davis, GLET Representative, the control efficiencies for CO and VOC emissions are "greater than 90%." The District will assume a 90% control efficiency to remain conservative.

Calculating for the MCET derives the following:

E_{NOx} = 61 tpy – 16.9 tpy = 44.1 tpy
E_{CO} = 824.3 tpy – 82.4 tpy = 741.9 tpy
E_{VOC} = 14.7 tpy – 1.5 tpy = 13.2 tpy

MCET ($/yr) = (44.1 x $9,700) + (741.9 x $300) + (13.2 x $5,000) = $716,340/year

The cost of utilizing a $SCONO_X$ system ($2,146,931/year) is more than the MCET of $764,452/year. Therefore, this control technology will be removed from consideration

2. CO Cost Effectiveness Analysis: Oxidation Catalyst

The applicant is proposing to utilize an oxidation catalyst with CO emissions of 6.0 ppmv @ 15% O_2. Since this control technology is the most effective CO control technology listed in Step 3 that has not cost out, a cost effectiveness analysis is not required.

Step 5 - <u>Select BACT</u>

Option #1 ($SCONO_X$ System) was determined to not be cost effective. The applicant has proposed to utilize option #2 (CO oxidation catalyst) and natural gas as the CO control technology. Therefore BACT for the emission unit is determined to be a turbine with a CO oxidation catalyst fueled on natural gas.

BACT Analysis for NOx Emissions:

According to the BACT guideline approved in Project #1010207 (Simple Cycle Gas Fired Turbines < 50 MW Powering an Electrical Generation Operation), the following are possible controls for NOx emissions from similar operations.

Step 1 - <u>Identify All Possible Control Technologies</u>

General control for NO_X emissions include the following options:

1. Selective Catalytic Reduction (SCR) systems: consist of injecting ammonia upstream of a catalyst bed. The ideal operating temperature for a conventional SCR catalyst is 600 – 750 °F (titanium oxide). High temperature zeolite SCR catalysts have been developed that permit continuous SCR operation at temperatures as high as 1,050 °F. High temperature catalysts must be used when the SCR system needs to be placed upstream of the Heat Recovery Steam Generators (HRSG).

2. SCONO$_X$™: employs a precious metal catalyst and a NO_X absorption/regeneration process step to convert CO and NO_X into CO_2, H_2O, and N_2. The principle advantage of the SCONO$_X$™ technology over SCR is the elimination of ammonia emissions and the simultaneous reduction of CO, VOC, and NO_X. SCONO$_X$™ has a maximum operating temperature of ≈ 700 °F

3. Catalytic Combustors (Xonon™ technologies): are flameless processes that allow fuel oxidation to take place at temperatures well below the normal lean flammability limits of the air-fuel mixture. For this reason, the use of catalysts in gas turbine combustion to replace part of the thermal reaction zone allows stable combustion to occur at peak temperatures that are as much as 1,800 °F lower than those of conventional combustors.

4. Dry Low NO_X (DLN) Combustors: operate in a pre-mixed mode, where air and fuel are mixed before entering the combustor. An important advantage of the DLN combustor is that the amount of NO_X formed does not increase with an increase in residence time. This means that DLN systems can be designed with long residence times to achieve low CO and low VOC emissions, while maintaining low NO_X levels.

5. Water/Steam Injection: has been used for the past 25 years to control NO_X emissions from gas turbines. Manufacturers typically guarantee water injected combustors to 42 ppmv when firing natural gas. The maximum allowable water injection rate is determined by the CO and VOC limits on the unit (as water injection has a quenching effect that increases emissions of "products of incomplete combustion") and the rapid wear caused by direct water impingement on the combustor liner.

NO_X Emissions Control Technologies

a. SCONO$_X$™
b. Catalytic Combustors (Xonon™ technologies)
c. Selective Catalytic Reduction (SCR) systems
d. Dry Low NO_X (DLN) Combustors
e. Water/Steam Injection

Step 2 - <u>Eliminate Technologically Infeasible Options</u>

As discussed in the CO Top-Down BACT analysis, the Xonon technology is technologically feasible. Therefore, this control technology will be removed from consideration.

All remaining control options listed in step 1 are technologically feasible.

Step 3. Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor

1. $SCONO_X$™ - ≤ 2.5 ppmv
2. Selective Catalytic Reduction - ≤ 5[4] ppmv
3. Dry Low NO_X burner - ≤ 25[5] ppmv
4. Water Injection - ≤ 42 ppmv

Step 4. Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

District Policy establishes annual cost thresholds for imposed control based upon the amount of pollutants abated by the controls. If the cost of control is at or below the threshold, it is considered a cost effective control. If the cost exceeds the threshold, it is not cost effective and the control is not required. Per District BACT Policy, the maximum cost limit for NO_X reduction is $9,700 per ton of NO_X reduced.

1. NO_X Cost Effectiveness Analysis:
$SCONO_X$ Systems (by Goal Line Environmental Technologies)

As demonstrated in the CO Top-Down BACT analysis, the $SCONO_X$ technology is not a cost effective technology. Therefore, this control technology will be removed from consideration.

2. NO_X Cost Effectiveness Analysis:
Turbine equipped with SCR System (5 ppmv NO_X @ 15% O_2)

The applicant is proposing to utilize a Selective Catalytic Reduction system with NO_X emissions of 3.7 ppmv @ 15% O_2. Since this control technology is the most effective NO_X control technology listed in Step 3, a cost effectiveness analysis is not required.

Step 5. Select BACT

BACT for the emission unit is determined to be the use of a Selective Catalytic Reduction system with emissions of less than or equal to 5 ppmv @ 15% O_2. The

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[4] Selective Catalytic Reduction (SCR) systems are capable of achieving emission levels less than 5 ppmv NO_X, but achieving such emissions has not been fully demonstrated on a consistent basis.
[5] It has generally been noted that Turbine manufacturers commonly guarantee NO_X emissions of 25 ppmv @ 15% O_2.

facility has proposed to use a Selective Catalytic Reduction system with emissions of less than or equal to 3.7 ppmv @ 15% O_2; therefore, BACT is satisfied.

BACT Analysis for VOC Emissions:

According to the BACT guideline approved in Project #1010207 (Simple Cycle Gas Fired Turbines < 50 MW Powering an Electrical Generation Operation), the following are possible controls for VOC emissions from similar operations.

Step 1 - Identify All Possible Control Technologies

1. SCONO$_X$™: employs a precious metal catalyst and a NO_X absorption/regeneration process step to convert CO and NO_X into CO_2, H_2O, and N_2. The principle advantage of the SCONO$_X$™ technology over SCR is the elimination of ammonia emissions and the simultaneous reduction of CO, VOC, and NO_X. SCONO$_X$™ has a maximum operating temperature of $\approx$ 700 °F

2. Oxidation Catalysts: utilizes the use of a catalyst bed (platinum based) at elevated temperatures in the range of 500-900 degree F in the exhaust stack to create an intermediate chemical reaction to disassociate the CO & VOC molecules and reduce the CO & VOC emissions.

3. PUC quality natural gas.

VOC Emissions Control Technologies

a. SCONO$_X$™
b. CO/VOC Oxidation Catalysts
c. PUC quality natural gas

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

In order to determine the control efficiency of a given control method, the industry standard must first be determined. The industry standard is typically established as the industrywide average baseline emission rate for the device in question.

As discussed in the CO Top-Down BACT analysis above, the industry standard for VOC emissions was determined to be 6.25 ppmv (0.008 lb/MMBtu) for this class and category of source.

Therefore, the proposed emissions from the gas turbines using industry standard values can be calculated as:

VOC (annual):

$$\frac{0.008\ \text{lb}}{\cancel{\text{MMBtu}}} \left| \frac{459.6\ \cancel{\text{MMBtu}}}{\cancel{\text{hr}}} \right| \frac{8{,}000\ \cancel{\text{hr}}}{\text{year}} = 29{,}414\ \text{lb VOC/year}$$

(6.25 ppmv @ 15% O_2 = 0.008 lb/MMBtu)

PE_{VOC} = 29,414 lb VOC/year = 14.7 tons VOC/year

d. Per GLET, the manufacturer of SCONO$_X$™, the District will assume a 90% VOC control efficiency for the installation of a SCONO$_X$ system. The industry standard turbine VOC emissions using a SCONO$_X$ system is:

VOC (annual):

$$\frac{29{,}414\ \text{lb VOC}}{\text{year}} \left| \frac{(1-90\%)}{1} \right. = 2941\ \text{lb VOC/year}$$

PE_{VOC} = 2,941 lb VOC/year = 1.5 tons VOC/year

The District will assume a 71% VOC control efficiency (as stated on BACT guideline 3.4.4) for the installation of an oxidation catalyst. The industry standard turbine VOC emissions using an oxidation catalyst is:

VOC (annual):

$$\frac{29414\ \text{lb VOC}}{\text{year}} \left| \frac{(1-71\%)}{1} \right. = 8{,}530\ \text{lb VOC/year}$$

PE_{VOC} = 8,530 lb VOC/year = 4.3 tons VOC/year

Control Method	Industry Standard Emissions		Controlled Emissions		Overall Control efficiency
	lb/year	ton/year	lb/year	ton/year	
a. SCONO$_X$	29,414	14.7	2,941	1.5	90%
b. CO/VOC Oxidation Catalyst	29,414	14.7	8,530	4.3	71%
c. Natural gas	29,414	14.7	29,414	14.7	0%

VOC Emission Control Technology Rankings

Rank	Control Efficiency
#1. SCONO$_X$ System	90%
#2. CO/VOC Oxidation Catalyst	71%
#3. Natural gas	0%

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

District Policy establishes annual cost thresholds for imposed control based upon the amount of pollutants abated by the controls. If the cost of control is at or below the threshold, it is considered a cost effective control. If the cost exceeds the threshold, it is not cost effective and the control is not required. Per District BACT Policy, the maximum cost limit for VOC reduction is $5,000 per ton of VOC reduced.

1. VOC Cost Effectiveness Analysis:
SCONO$_X$ System

As demonstrated in the CO Top-Down BACT analysis, the SCONO$_X$ technology is not a cost effective technology. Therefore, this control technology will be removed from consideration.

2. VOC Cost Effectiveness Analysis:
Oxidation Catalyst

The applicant is proposing to utilize an oxidation catalyst to control VOC emissions. Since this control technology is the most effective VOC control technology listed in Step 3, a cost effectiveness analysis is not required.

Step 5 - Select BACT

The applicant has proposed to utilize option #2 (Oxidation Catalyst) as the VOC control technology. Therefore BACT for the emission unit is determined to be a turbine equipped with an oxidation catalyst.

BACT Analysis for PM_{10} Emissions:

According to the BACT guideline approved in Project #1010207 (Simple Cycle Gas Fired Turbines < 50 MW Powering an Electrical Generation Operation), the following are possible controls for PM_{10} emissions:

Step 1 - Identify All Possible Control Technologies

1. Air inlet filter, lube oil vent coalescer (or equivalent), and PUC regulated natural gas fuel (1.0 gr-S/100 dscf) – Achieved in Practice

2. PUC regulated natural gas fuel (1.0 gr-S/100 dscf) – specified as achieved in practice BACT in the California Air Resources Board's September 1999

Guidance for Power Plant Siting and Best Available Control Technology document (for turbines ≥ 50 MW). - Achieved in Practice

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Air inlet cooler/filter, lube oil vent coalescer (or equivalent), and PUC regulated natural gas fuel (1.0 gr-S/100 dscf).

2. PUC regulated natural gas fuel (1.0 gr-S/100 dscf).

Step 4 - Cost Effectiveness Analysis

The applicant is proposing to use an air inlet cooler/filter, lube oil vent coalescer (or equivalent), and natural gas fuel (0.25 gr-S/100 dscf). This is the highest ranking technologically feasible option, therefore a cost effective analysis will not be necessary.

Step 5 - Select BACT

The applicant has proposed to an air inlet cooler/filter, lube oil vent coalescer (or equivalent), and natural gas fuel (0.25 gr-S/100 dscf). Therefore, BACT for this class of source is satisfied.

BACT Analysis for SO_X Emissions:

According to the BACT guideline approved in Project #1010207 (Simple Cycle Gas Fired Turbines < 50 MW Powering an Electrical Generation Operation), the following are possible controls for SO_X emissions from similar operations.

Step 1 - Identify All Possible Control Technologies

1. PUC regulated natural gas fuel (1.0 gr-S/100 dscf) – specified as achieved in practice BACT in the California Air Resources Board's September 1999 Guidance for Power Plant Siting and Best Available Control Technology document (for turbines ≥ 50 MW).

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. PUC regulated natural gas fuel (1.0 gr-S/100 dscf).

Step 4 - Cost Effectiveness Analysis

The facility has proposed to use utility grade natural gas with a sulfur content of less than or equal to 1.0 grains per 100 dscf. Since this is the most effective control option, a cost effectiveness analysis is not required.

Step 5 - Select BACT

The applicant has proposed to use natural gas with a sulfur content of less than or equal to 1.0 grains per 100 dscf as the SO_X control technology. Therefore, BACT for this class of source is satisfied.

Appendix I
BACT Guideline - Simple Cycle Gas Fired Turbine < 50 MW, Powering an Electrical Generation Operation

Proposed Pages for the BACT Clearinghouse
San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline X.X.X*

Last Update: April 10, 2001

Emissions Unit: Simple Cycle Gas Fired Turbine < 50 MW, Powering an Electrical Generation Operation

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
VOC	PUC quality natural gas (2 ppmv @ 15% O_2)	1. $SCONO_X$ system 2. Oxidation catalyst	
SO_X	PUC quality natural gas (1.0 gr/100 scf)		
NO_X	5 ppmv @ 15% O_2 (Selective Catalytic Reduction (SCR) systems, or equal)	$SCONO_X$ system	
PM_{10}	Air Inlet Cooler/Filter, Lube Oil Vent Coalescer (or Equivalent), and Natural Gas Fuel (1.0 gr-S/100 dscf)		

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline X.X.XA

Emission Unit: Natural Gas Fired Twin Pac Turbine Peaking Power Generation Unit

Equipment Rating: 24.7 MW (each) (49.3 MW nominal rating)

Facility: CalPeak Power LLC.

References: ATC #: C-3811-1-0 & -2-0
Project #: C-1010207

Location: Mendota, CA

Date of Determination: April 10, 2001

Pollutant	BACT Requirements
VOC	2.0 ppmvd @ 15% O_2 utilizing an oxidation catalyst and natural gas fuel
SO_X	1.0 gr-S/100 dscf natural gas fuel
NO_X	3.4 ppmvd @ 15% O_2 (3 hour average) utilizing Dry Low NO_X combustors, Selective Catalytic Reduction with ammonia injection, and natural gas fuel
CO	BACT NOT TRIGGERED
PM_{10}	Natural gas fuel (1.0 gr-S/100 dscf), air inlet cooler/filter, and lube oil vent coalescer to achieve an overall PM_{10} emission factor of 0.0066 lb/MMBtu.

BACT Status:

_X_ Achieved in practice (NO_X, VOC & PM_{10}) ___ Small Emitter ___ T-BACT
___ Technologically feasible BACT
___ At the time of this determination achieved in practice BACT was equivalent to technologically feasible BACT
___ Contained in EPA approved SIP
___ The following technologically feasible options were not cost effective:
1) SCONO$_X$ System (NO_X and VOC)
___ Alternate Basic Equipment
___ The following alternate basic equipment was not cost effective:

Appendix II

PTOs N-2246-1-1 & -2-1, and N-583-1-2

INSPECTION WORKSHEET

EXPIRATION DATE: 09/30/2002

LEGAL OWNER OR OPERATOR: TURLOCK IRRIGATION DISTRICT
MAILING ADDRESS: 333 CANAL DRIVE
TURLOCK, CA 95380

LOCATION: 325 WASHINGTON
TURLOCK, CA 95380

EQUIPMENT DESCRIPTION:
TURBINE/GENERATOR SET #1, 25.8 MW GENERAL ELECTRIC FRAME 5, MODEL PG 5361

CONDITIONS

1. The primary fuel is to be natural gas with a #2 distillate fuel (sulfur content less than 0.25% by weight) as a backup and to be used only in the event of a natural gas shortage. [District Rule 2201]
2. In the event of a natural gas shortage, SOx emissions shall not exceed 5,950 pounds during any one month for both N-2246-1-1 and N-2246-2-1 combined. [District Rule 2201]
3. The NOx emission concentration shall not exceed 42 ppmvd @ 15% O2 except for thermal stabilization or reduced load period, as defined in Rule 4703, and the NOx emission rate shall not exceed 51 pounds in any one hour. [District Rule 4703 & Rule 2201]
4. The CO emission concentration shall not exceed 200 ppmvd @ 15% O2 except for thermal stabilization or reduced load period, as defined in Rule 4703. [District Rule 4703]
5. The Particulate emissions shall not exceed 150 pounds during any one day for both N-2246-1-1 and N-2246-2-1 combined. [District Rule 2201]
6. The NOx emissions shall not exceed 1,020 pounds during any one day and shall not exceed 8,517 pounds during any one month for both N-2246-1-1 and N-2246-2-1 combined. [District Rule 2201]
7. The operation of this unit shall be limited to less than 877 hours during any one year. [District Rule 4703]
8. The NOx emissions from both N-2246-1-1 and N-2246-2-1 combined shall be less than 50 tons during any one year. [District Rule 2520]
9. The CO emissions from both N-2246-1-1 and N-2246-2-1 combined shall be less than 100 tons during any one year. [District Rule 2520]
10. The SOx emissions from both N-2246-1-1 and N-2246-2-1 combined shall be less than 70 tons during any one year. [District Rule 2520]
11. Source testing to demonstrate compliance with NOx and CO limits at standard conditions and the percent turbine efficiency (EFF) shall be conducted on a biennial basis in accordance with Rule 4703 - "Stationary Gas Turbines". [District Rule 4703]
12. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. [District Rule 1081]
13. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
14. Install, operate, and maintain calibration equipment that continuously measures and records control system operating parameters and elapsed time of operation. [District Rule 4703]
15. Maintain an operating log that includes, on a daily basis: the actual local start-up and stop time; length and reason for reduced load periods; total hours of operation, and type and quantity of fuels used. [District Rule 4703]
16. Maintain a log that shows the daily and monthly NOx emissions. [District Rule 2201]
17. All records shall be retained for a minimum of 2 years, and shall be made available for District inspection upon request. [District Rule 1070]

18. The NOx emission concentration shall be determined using EPA Methods 7E or 20. [District Rule 4703]
19. The CO emission concentration shall be determined using EPA Methods 10 or 10B. [District Rule 4703]
20. The Oxygen content of the exhaust gas shall be determined using EPA Methods 3, 3A, or 20. [District Rule 4703]

INSPECTION WORKSHEET

EXPIRATION DATE: 09/30/2002

LEGAL OWNER OR OPERATOR: TURLOCK IRRIGATION DISTRICT
MAILING ADDRESS: 333 CANAL DRIVE
TURLOCK, CA 95380

LOCATION: 325 WASHINGTON
TURLOCK, CA 95380

EQUIPMENT DESCRIPTION:
TURBINE/GENERATOR SET #2, 25.8 MW GENERAL ELECTRIC FRAME 5, MODEL PG 5361

CONDITIONS

1. The primary fuel is to be natural gas with a #2 distillate fuel (sulfur content less than 0.25% by weight) as a backup and to be used only in the event of a natural gas shortage. [District Rule 2201]
2. In the event of a natural gas shortage, SOx emissions shall not exceed 5,950 pounds during any one month for both N-2246-1-1 and N-2246-2-1 combined. [District Rule 2201]
3. The NOx emission concentration shall not exceed 42 ppmvd @ 15% O2 except for thermal stabilization or reduced load period, as defined in Rule 4703, and the NOx emission rate shall not exceed 51 pounds in any one hour. [District Rule 4703 & Rule 2201]
4. The CO emission concentration shall not exceed 200 ppmvd @ 15% O2 except for thermal stabilization or reduced load period, as defined in Rule 4703. [District Rule 4703]
5. The Particulate emissions shall not exceed 150 pounds during any one day for both N-2246-1-1 and N-2246-2-1 combined. [District Rule 2201]
6. The NOx emissions shall not exceed 1,020 pounds during any one day and shall not exceed 8,517 pounds during any one month for both N-2246-1-1 and N-2246-2-1 combined. [District Rule 2201]
7. The operation of this unit shall be limited to less than 877 hours during any one year. [District Rule 4703]
8. The NOx emissions from both N-2246-1-1 and N-2246-2-1 combined shall be less than 50 tons during any one year. [District Rule 2520]
9. The CO emissions from both N-2246-1-1 and N-2246-2-1 combined shall be less than 100 tons during any one year. [District Rule 2520]
10. The SOx emissions from both N-2246-1-1 and N-2246-2-1 combined shall be less than 70 tons during any one year. [District Rule 2520]
11. Source testing to demonstrate compliance with NOx and CO limits at standard conditions and the percent turbine efficiency (EFF) shall be conducted on a biennial basis in accordance with Rule 4703 - "Stationary Gas Turbines". [District Rule 4703]
12. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. [District Rule 1081]
13. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
14. Install, operate, and maintain calibration equipment that continuously measures and records control system operating parameters and elapsed time of operation. [District Rule 4703]
15. Maintain an operating log that includes, on a daily basis: the actual local start-up and stop time; length and reason for reduced load periods; total hours of operation, and type and quantity of fuels used. [District Rule 4703]
16. Maintain a log that shows the daily and monthly NOx emissions. [District Rule 2201]
17. All records shall be retained for a minimum of 2 years, and shall be made available for District inspection upon request. [District Rule 1070]

18. The NOx emission concentration shall be determined using EPA Methods 7E or 20. [District Rule 4703]
19. The CO emission concentration shall be determined using EPA Methods 10 or 10B. [District Rule 4703]
20. The Oxygen content of the exhaust gas shall be determined using EPA Methods 3, 3A, or 20. [District Rule 4703]

CONDITIONS FOR PERMIT N-583-1-2

INSPECTION WORKSHEET

EXPIRATION DATE: 04/30/2004

LEGAL OWNER OR OPERATOR: NORTHERN CALIFORNIA POWER AGENCY
MAILING ADDRESS: 180 CIRBY WAY
ROSEVILLE, CA 95678

LOCATION: LOWER SACRAMENTO & TURNER RD
LODI, CA 95240

EQUIPMENT DESCRIPTION:
GENERAL ELECTRIC (MODEL PG 5361) 25.24 MW PEAKLOAD BLACK START POWER PLANT SERVED BY A 325 MMBTU/HR GENERAL ELECTRIC MODEL MS 5001P "FRAME 5" GAS TURBINE ENGINE.

CONDITIONS

1. The emissions from the lube oil vent shall be controlled such that the opacity does not exceed 0%. [District Rule 2201]
2. Water shall be injected into the turbine's combustor at a minimum water-to-fuel ratio of 0.5 to 1 by weight when firing at 100% load. [District NSR Rule]
3. The water-to-fuel ratio shall be recorded at all times using an averaging interval not to exceed 15 minutes. [District NSR Rule]
4. NOx emissions concentration shall not exceed 42 ppmvd at 15% O2. [District Rule 4703]
5. The turbine shall be fired only on natural gas or #2 fuel oil. The turbine may be fired on #2 fuel oil only in the event of natural gas curtailment or for fuel oil system reliability testing. [District NSR Rule]
6. The sulfur content of any fuel oil purchased after May 1, 1992 shall not exceed 0.05% by weight. Verification of the fuel oil sulfur content shall be kept on site, and shall be made available for District inspection upon request. [District NSR Rule]
7. The maximum natural gas usage shall not exceed 2,582.3 MMBtus during any one day. [District Rule 2201]
8. The maximum fuel oil #2 usage shall not exceed 7,227 gallons during any one day. [District Rule 2201]
9. The emission concentration shall not exceed: 0.025 lbs/MMBtu for VOC; 0.0677 lbs/MMBtu for CO; 0.013 lbs/MMBtu for PM10; and 0.0006 lbs/MMBtu for SOx while firing on natural gas. [District Rule 2201]
10. The emission concentration shall not exceed: 0.025 lbs/MMBtu for VOC; 0.0192 lbs/MMBtu for CO; 0.031 lbs/MMBtu for PM10; and 0.2525 lbs/MMBtu for SOx while firing on fuel oil #2. [District Rule 2201]
11. The operation of the turbine shall be ceased during any day for which the District predicts or declares an Episode Stage 2. [District NSR Rule and District Rule 6080]
12. The operation of the gas turbine shall be limited to less than 877 hours during any one year. [District Rule 4703]
13. Source testing to demonstrate compliance with NOx and CO limits at standard conditions and the percent turbine efficiency (EFF) shall be conducted on a biennial basis in accordance with Rule 4703 - "Stationary Gas Turbines". [District Rule 4703]
14. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. [District Rule 1081]
15. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
16. Install, operate, and maintain calibration equipment that continuously measures and records control system operating parameters and elapsed time of operation. [District Rule 4703]
17. Maintain an operating log that includes, on a daily basis: the actual local start-up and stop time; length and reason for reduced load periods; total hours of operation, and type and quantity of fuels used. [District Rule 4703]

18. Maintain a log that shows the cumulative operating hours for each calendar year. [District Rule 4703]
19. All records shall be retained for a minimum of 2 years, and shall be made available for District inspection upon request. [District Rule 1070]
20. Source testing to measure concentrations of oxides of nitrogen (as NO2) shall be conducted using EPA methods 7E or 20. [District Rule 4703]
21. Source testing to measure concentrations of carbon monoxide (CO) shall be conducted using EPA methods 10 or 10B. [District Rule 4703]
22. Source testing to measure the stack gas oxygen shall be conducted using EPA methods 3, 3A, or 20. [District Rule 4703]
23. The demonstrated percent efficiency of the gas turbine shall be determined using the fuel consumption and power output consistent with District Rule 4703 section 6.4.6. [District Rule 4703]

Appendix III
Guidance for Power Plant Siting and Best Available Control Technology Table III-1

- area attainment status,

- gas turbine exhaust gas temperature for simple-cycle power plant configuration (for example, use of aeroderived versus industrial frame gas turbine), and

- use and function of gas turbine.

It is the responsibility of the permitting agency to make its own BACT determination for the class and category of gas turbine application. The BACT emission levels are intended to apply to the emission concentrations as exhausted from the stacks. Summaries of information and findings utilized in assessing BACT for gas turbine emissions follow the tables. Supporting material is presented in Appendix C.

Table III-1: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Simple-Cycle Power Plant Configurations

NO_X	CO	VOC	PM_{10}	SO_X
5 ppmvd @ 15% O_2, 3-hour rolling average	6 ppmvd @ 15% O_2, 3-hour rolling average	2 ppmvd @ 15% O_2, 3-hour rolling average OR 0.0027 pounds per MMBtu (based on higher heating value)	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 (no more than 0.55 ppmvd @ 15% O_2)

Appendix IV
District Rule 4703 CO Requirement

5.1.2 The owner or operator of any stationary gas turbine system listed below shall not operate such unit under load conditions, excluding the thermal stabilization period or reduced load period, which results in the measured NOx emissions concentration exceeding the compliance limit listed below.

Stationary Gas Turbine	Compliance Limit, NOx ppm at 15% O_2	
	Gas	Oil
General Electric Frame 7 with Quiet Combustors	18 x EFF/25	42 x EFF/25
Solar Saturn 1100 horsepower gas turbine powering centrifugal compressor	50	50

Gas includes natural gas, digester gas, and landfill gas.
Oil includes kerosene, jet, and distillate. Sulfur content of oil shall be less than 0.05%.

5.2 CO Emissions

The owner or operator of any stationary gas turbine system shall not operate such unit under load conditions, excluding the thermal stabilization period and the reduced load period, which results in the measured CO emissions concentration exceeding the compliance limits listed below:

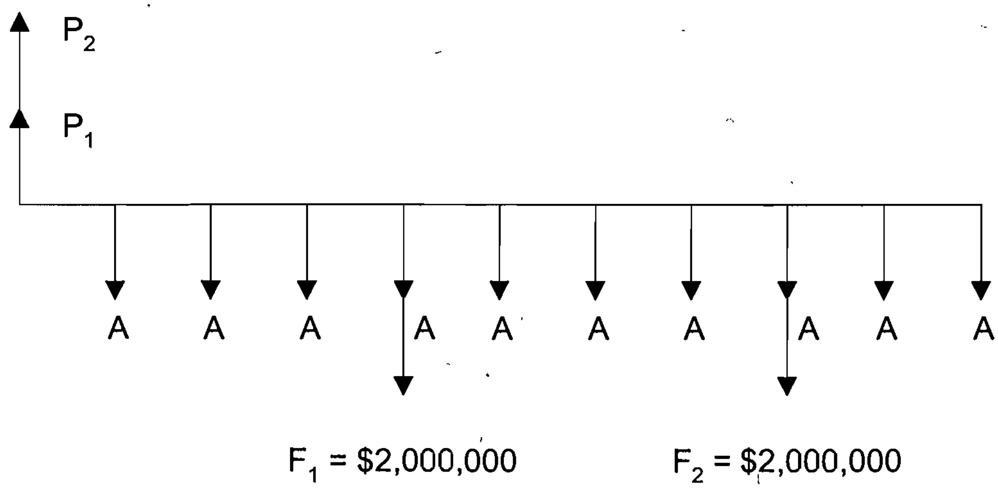
Stationary Gas Turbine	Compliance Limit, CO ppm at 15% O_2
Units subject to Section 5.1.1	200
General Electric Frame 7	25
General Electric Frame 7 with Quiet Combustors	52
Solar Saturn 1100 horsepower gas turbine powering centrifugal compressor	250

Appendix V

Calculation of Annual Cost for $SCONO_X$ Catalyst Replacement

Calculation of an Equivalent Annual Cost of the $SCONO_X$ catalyst replacement:

According to Goal Line Environmental Technologies, the $SCONO_X$ catalyst has a life span of approximately three to five years. Therefore, it is assumed that, on average, the catalyst must be replaced two times during the ten tear life span. Information from the BACT determination performed for Southern region project #990210 (the most recent revision of guideline 3.4.2, which was approved in Q1, 2000) indicates that the replacement cost of a $SCONO_X$ catalyst is approximately 50% of the original system cost. Therefore, the applicant must purchase a new catalyst bed at $4,000,000 × 0.5 = $2,000,000 every four years. These future costs must be converted to an equivalent annual cost over the ten year life span, as illustrated below:



Step 1:
Each future cost (F_1, F_2) will be converted to a present worth value (P_1, P_2) assuming an interest rate of 10% and a 10 year life span using the following single payment present worth equation:

$$P = F \times \left[\frac{1}{(1+i)^n} \right]$$

where:

P	=	present worth
F	=	future cost
i	=	interest rate
n	=	life span

$$P_1 = \$2{,}000{,}000 \times \left[\frac{1}{(1+0.1)^4} \right] = \$1{,}366{,}027$$

$$P_2 = \$2{,}000{,}000 \times \left[\frac{1}{(1+0.1)^8}\right] = \$933{,}015$$

Step 2:

The total present worth value (P_1 + P_2) will be converted to an equivalent annual cost (A) assuming an interest rate of 10% and a 10 year life span using the following capital recovery equation:

$$A = P \times \left[\frac{i \times (1+i)^n}{(1+i)^n - 1}\right]$$

where:

P	=	present worth
A	=	equivalent annual cost
i	=	interest rate
n	=	life span

$$A = (\$1{,}366{,}027 + \$933{,}015) \times \left[\frac{0.1 \times (1+0.1)^{10}}{(1+0.1)^{10} - 1}\right] = \$374{,}054 / year$$

Proposed Pages for the BACT Clearinghouse
San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline X.X.X*

Last Update: April 18, 2001

Emissions Unit: Simple Cycle Gas Fired Turbine < 50 MW, Powering an Electrical Generation Operation

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
VOC	2 ppmv @ 15% O_2 ($SCONO_X$ system, Oxidation Catalyst, or equal), and PUC quality natural gas (1.0 gr/100 scf)		
SO_X	PUC quality natural gas (1.0 gr/100 scf)		
NO_X	5 ppmv @ 15% O_2 (Selective Catalytic Reduction (SCR) systems, or equal)	$SCONO_X$ system	
PM_{10}	Air Inlet Cooler/Filter, Lube Oil Vent Coalescer (or Equivalent), and PUC quality natural gas (1.0 gr-S/100 dscf)		
CO	6 ppmv @ 15% O_2 ($SCONO_X$ system, Oxidation Catalyst, or equal), and PUC quality natural gas (1.0 gr/100 scf)		

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline X.X.XA

Emission Unit: Natural Gas Fired GE LM6000 Turbine Peaking Power Generation Unit

Equipment Rating: 47.5 MW (each) (95.0 MW nominal rating)

Facility: Hanford LP.

References: ATC #: C-603-11-0 and –12-0
Project #: C-1010451

Location: Hanford, CA

Date of Determination: April 18, 2001

Pollutant	BACT Requirements
VOC	2.0 ppmvd @ 15% O_2 utilizing an oxidation catalyst and natural gas fuel
SO_X	0.25 gr-S/100 dscf natural gas fuel
NO_X	3.7 ppmvd @ 15% O_2 (3 hour average) utilizing water-spray premixed combustion system, Selective Catalytic Reduction (SCR) with ammonia injection, and natural gas fuel
CO	6.0 ppmvd @ 15% O_2 utilizing an oxidation catalyst and natural gas fuel
PM_{10}	Natural gas fuel (0.25 gr-S/100 dscf), air inlet cooler/filter, and lube oil vent coalescer to achieve an overall PM_{10} emission factor of 0.0066 lb/MMBtu.

BACT Status:

_X_ Achieved in practice (CO) __ Small Emitter __ T-BACT
___ Technologically feasible BACT
___ At the time of this determination achieved in practice BACT was equivalent to technologically feasible BACT
___ Contained in EPA approved SIP
___ The following technologically feasible options were not cost effective:
1) $SCONO_X$ System (CO)
___ Alternate Basic Equipment
___ The following alternate basic equipment was not cost effective:

Completed CAPCOA BACT Clearinghouse Forms

(except "ATC Issue Date" and "Today's Date")

Mail to: CAPCOA BACT Clearinghouse Project Assessment Branch P.O. Box 2815 Sacramento, CA 95812	For CAPCOA use only Record No.: ;Form No.: ;BLIS District code: Codes- EPA Source: ;SCAQMD: ;EPA ID No.: ARB Sc: ;BLIS Process: ;AIRS Facility No.:

CAPCOA BACT DETERMINATION REPORTING FORM

Instructions: Complete this form when issuing and authority to construct. Please use one form per determination (i.e. pollutant). Section A need only be completed on one form in the case of a source with multiple determinations. See the reverse side for descriptions of the field identifiers used below. Please attach a copy of the permit conditions if practical. Please call (916) 327-5601 for clarification of any questions. (1/5/94)

SECTION A. Source Information

Company and Project Name: Hanford LP (HEP)
Facility Address: 10550 Idaho Avenue SIC Code: 1623

Application No.: 1010451 Authority to Construct No.: C-603-11-0, -12-0 Authority to Construct Issue Date:

District: SJVUAPCD; District Contact: Seyed Sadredin; Phone No.: (559) 230-5900

Est. Startup Date: 09/2001; Today's Date: ___________; Permit Status: New

Basic Equip./Process (include make and model): Two 47.5 MW General Electric LM6000 PC Sprint natural gas fired combustion turbine/generators (CTG) with water-spray premixed combustion systems, Selective Catalytic Reduction (SCR) systems, and oxidation catalysts.

Rated Capacity: Input: 459.6 MMBtu/hr Output: __________; SCC Code: _______________

Fuel Type: Natural Gas
Backup Fuel(s): N/A ;Project Cost: $______

CTION B. Control Data Pollutant: Carbon Monoxide (CO).

Control Equip. (include make and model): Oxidation Catalyst, Natural Gas

Emissions: Uncontrolled:_____lbm/day Controlled Limit: 6.2 lbm/day

Enforceable Permit Emissions Limit(s): #1: 6 ppmv @ 15% O_2

Emission Type: point; Cost of Control Equipment:________________________

Regulatory Requirement: District-Defined BACT; Other:________________________

BACT/LAER Specification:__ Reference or Basis: Manufacturer guarantee.

Mass Emission Rate: 6.2 lb-CO/hr; Destruction Efficiency (%):_______
Normalized Mass Emis. Rate: 0.0135 lbm/MMBtu; _______g/hp-hr; ____ lbm per ton input
Emission Concentration: 6 ppmv @ 15% O_2.
Method of Compliance Verification: Third Party Source Testing.

Other Relevant Permit Limits: Time of Operation: 24 hr/day.
Fuel use:__________________; Percent Capacity/Use:__________________
Throughput:__________________ Other:__.
Remarks: ____

APPENDIX D

AP-42 Table 3.1-2a (4/00)

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Pollutant	Emission Factors[a] - Uncontrolled			
	Natural Gas-Fired Turbines[b]		Distillate Oil-Fired Turbines[d]	
	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[e] (Fuel Input)	Emission Factor Rating
CO_2[f]	110	A	157	A
N_2O	0.003[g]	E	ND	NA
Lead	ND	NA	1.4 E-05	C
SO_2	0.94S[h]	B	1.01S[h]	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04[j]	E
TOC[k]	1.1 E-02	B	4.0 E-03[l]	C
PM (condensible)	4.7 E-03[l]	C	7.2 E-03[l]	C
PM (filterable)	1.9 E-03[l]	C	4.3 E-03[l]	C
PM (total)	6.6 E-03[l]	C	1.2 E-02[l]	C

[a] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

[b] SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

[d] SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[e] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[f] Based on 99.5% conversion of fuel carbon to CO_2 for natural gas and 99% conversion of fuel carbon to CO_2 for distillate oil. CO_2 (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(C)(D), where %CON = weight percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10^6scf. For distillate oil, CO_2 (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.

[g] Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).

[h] All sulfur in the fuel is assumed to be converted to SO_2. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).

[j] VOC emissions are assumed equal to the sum of organic emissions.

[k] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.

[l] Emission factors are based on combustion turbines using water-steam injection.

APPENDIX E

Conversion Worksheet

	SELECTION #
COAL (ANTHRACITE)	0
COAL (BITUMINOUS)	1
COAL (LIGNITE)	2
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	3
GAS (NATURAL)	4
GAS (PROPANE)	5
GAS (BUTANE)	6
WOOD	7
WOOD BARK	8
MUNICIPAL SOLID WASTE	9

STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3%	
Type of fuel (use table above)	4 GAS
O2 correction (i.e., 3%)	15 %
Enter concentrations	
NOx	3.7 ppmv
CO	6 ppmv
VOC (as methane)	2 ppmv

CALCULATED EQUIVALENT LB/MMBTU VALUES	
NOx	0.0136 LB/MMBTU
CO	0.0135 LB/MMBTU
VOC (as methane)	0.0026 LB/MMBTU

pV = R*T		
pressure (p)	1	atm
universal gas constant (R*)	0.7302	atm-scf/lbmole-oR
temperature (oF)	60	oF
calculated		
molar specific volume (V)	379.5	scf/lbmole
Molecular weights		
NOx	46	lb/lb-mole
CO	28	lb/lb-mole
VOC (as methane)	16	lb/lb-mole

F FACTORS FROM EPA METHOD 19			
COAL (ANTHRACITE)	10100	DSCF/MMBTU	COAL
COAL (BITUMINOUS)	9780	DSCF/MMBTU	COAL
COAL (LIGNITE)	9860	DSCF/MMBTU	COAL
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	9160	DSCF/MMBTU	OIL
GAS (NATURAL)	8710	DSCF/MMBTU	GAS
GAS (PROPANE)	8710	DSCF/MMBTU	GAS
GAS (BUTANE)	8710	DSCF/MMBTU	GAS
WOOD	9240	DSCF/MMBTU	WOOD
WOOD BARK	9600	DSCF/MMBTU	WOOD BARK
MUNICIPAL SOLID WASTE	9570	DSCF/MMBTU	SOLID WASTE
F FACTOR USED IN CALCULATIONS	8710	DSCF/MMBTU	GAS

APPENDIX F

CARB Memorandum