



**OCT 07 2015**

Mr. Shamim Reza  
Linn Operating, Inc  
5201 Truxtun Ave, Suite 100  
Bakersfield, CA 93309

**Re: Proposed ATC / Certificate of Conformity (Significant Mod)  
District Facility # S-1246  
Project # S-1151997**

Dear Mr. Reza:

Enclosed for your review is the District's analysis of an application for Authority to Construct for the facility identified above. You requested that a Certificate of Conformity with the procedural requirements of 40 CFR Part 70 be issued with this project. The facility proposes to install one 5.67 MW cogeneration system at the Pan Fee Lease in Heavy Oil Western Stationary Source, Kern County, CA (Section 2, T31S, R22E).

After addressing all comments made during the 30-day public notice and the 45-day EPA comment periods, the District intends to issue the Authority to Construct with a Certificate of Conformity. Please submit your comments within the 30-day public comment period, as specified in the enclosed public notice. Prior to operating with modifications authorized by the Authority to Construct, the facility must submit an application to modify the Title V permit as an administrative amendment, in accordance with District Rule 2520, Section 11.5.

If you have any questions, please contact Mr. Jim Swaney, Permit Services Manager, at (559) 230-5900.

Thank you for your cooperation in this matter.

Sincerely,

Arnaud Marjollet  
Director of Permit Services

Enclosures

cc: Mike Tollstrup, CARB (w/enclosure) via email  
cc: Gerardo C. Rios, EPA (w/enclosure) via email

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Executive Director/Air Pollution Control Officer

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# San Joaquin Valley Air Pollution Control District

## Authority to Construct Application Review

Cogeneration System Consisting of One Natural Gas-Fired Turbine and Duct Burner

Facility Name:	Linn Operating, Inc	Date:	October 7, 2015
Mailing Address:	5201 Truxtun Ave, Suite 100 Bakersfield, CA 93309	Engineers:	Stanley Tom / Dustin Brown
Contact Person:	Shamim Reza	Lead Engineer	Joven Refuerzo
Telephone:	(661) 616-3889		
E-Mail:	SReza@linnenergy.com		
Application No:	S-1246-416-0		
Project No:	S-1151997		
Deemed Complete:	May 18, 2015		

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### I. Proposal

Linn Operating, Inc has requested an Authority to Construct (ATC) permit for the installation of one 5.67 MW (ISO rated) combined heat and power cogeneration system consisting of one 67.9 MMBtu/hr natural gas-fired Solar Model Taurus 60 (T-60) turbine and one 57 MMBtu/hr natural gas-fired Rentech duct burner with Rentech selective catalytic reduction (SCR) and CO catalyst and Heat Recovery Steam Generator (HRSG). The ratings are based upon the higher heating value of natural gas.

The facility has submitted an ATC application for an identical cogeneration operation at the 21Z Lease (Section 21, T30S, R22E). The 21Z Lease is not contiguous or adjacent to the Pan Fee Lease (Section 2, T31S, R22E). The cogeneration operation in this project will be installed at the Pan Fee Lease. Therefore, these two projects are separate Federal stationary sources and can be processed as separate projects.

Linn Operating, Inc has received their Title V Permit. This modification can be classified as a Title V significant modification pursuant to Rule 2520, and can be processed with a Certificate of Conformity (COC). Since the facility has specifically requested that this project be processed in that manner, the 45-day EPA comment period will be satisfied prior to the issuance of the Authority to Construct permit. Linn Operating, Inc must apply to administratively amend their Title V permit.

### II. Applicable Rules

Rule 1080	Stack Monitoring (12/17/92)
Rule 1081	Source Sampling (12/16/93)
Rule 1100	Equipment Breakdown (12/17/92)
Rule 2201	New and Modified Stationary Source Review Rule (4/21/11)
Rule 2410	Prevention of Significant Deterioration (6/16/11)

- Rule 2520 Federally Mandated Operating Permits (6/21/01)
- Rule 2540 Acid Rain Program (11/13/97)
- Rule 4001 New Source Performance Standards (4/14/99)
- Rule 4002 National Emissions Standards for Hazardous Air Pollutants (5/20/04)
- Rule 4101 Visible Emissions (2/17/05)
- Rule 4102 Nuisance (12/17/92)
- Rule 4201 Particulate Matter Concentration (12/17/92)
- Rule 4202 Particulate Matter Emission Rate (12/17/92)
- Rule 4305 Boilers, Steam Generators and Process Heaters – Phase 2 (8/21/03)
- Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3 (10/16/08)
- Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr (10/16/08)
- Rule 4703 Stationary Gas Turbines (9/20/07)
- Rule 4801 Sulfur Compounds (12/17/92)
- CH&SC 41700 Health Risk Assessment
- CH&SC 42301.6 School Notice
- Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
- California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

### III. Project Location

The facility is located at the Pan Fee Lease in the Heavy Oil Western Stationary Source, Kern County, CA (Section 2, T31S, R22E). The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

### IV. Process Description

The proposed equipment will be used to generate electricity and steam which will be used for facility operations. The combined cycle generator set is equipped with a waste heat recovery steam generator (HRSG).

### V. Equipment Listing

Permit #	Equipment Description
S-1246-416-0	5.67 MW (ISO RATED) COMBINED HEAT AND POWER COGENERATION SYSTEM CONSISTING OF ONE 67.9 MMBTU/HR NATURAL GAS-FIRED SOLAR MODEL TAURUS 60 (T-60) TURBINE AND ONE 57 MMBTU/HR NATURAL GAS-FIRED RENTECH DUCT BURNER WITH RENTECH SELECTIVE CATALYTIC REDUCTION (SCR) AND CO CATALYST AND HEAT RECOVERY STEAM GENERATOR (HRSG)

## VI. Emission Control Technology Evaluation

Emissions from natural gas-fired turbines include NO<sub>x</sub>, SO<sub>x</sub>, PM<sub>10</sub>, CO, and VOC.

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

Thermal NO<sub>x</sub> 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<sub>x</sub>, a form of thermal NO<sub>x</sub>, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NO<sub>x</sub>.

Fuel NO<sub>x</sub> is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N<sub>2</sub> in some natural gas, does not contribute significantly to fuel NO<sub>x</sub> formation. With excess air, the degree of fuel NO<sub>x</sub> formation is primarily a function of the nitrogen content in the fuel. When compared to thermal NO<sub>x</sub>, fuel NO<sub>x</sub> is not currently a major contributor to overall NO<sub>x</sub> emissions from stationary gas turbines firing natural gas.

The level of NO<sub>x</sub> formation in a gas turbine, and hence the NO<sub>x</sub> emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO<sub>x</sub> generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine.

### Selective Catalytic Reduction (SCR)

For control of NO<sub>x</sub>, the cogeneration unit will utilize selective catalytic reduction (SCR) with anhydrous ammonia injection.

SCR systems selectively reduce NO<sub>x</sub> emissions by injecting ammonia (NH<sub>3</sub>) into the exhaust gas stream upstream of a catalyst. NO<sub>x</sub>, NH<sub>3</sub>, and O<sub>2</sub> react on the surface of the catalyst to form molecular nitrogen (N<sub>2</sub>) and H<sub>2</sub>O. SCR is capable of over 90 percent NO<sub>x</sub> 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<sub>x</sub> and NH<sub>3</sub> to pass through the catalyst unreacted.

### Oxidation Catalyst (CO Catalyst)

For control of CO, the cogeneration unit will utilize a CO catalyst.

CO emissions result from incomplete combustion, CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO<sub>2</sub> at gas turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may

result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. Carbon monoxide emissions are also dependent on the loading of the gas turbine. For example, a gas turbine operating under a full load will experience greater fuel efficiencies which will reduce the formation of carbon monoxide. The opposite is also true, as gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide.

Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions. CO catalyst is also being used to reduce VOC and organic HAP emissions. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (CO<sub>2</sub>) and water as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement of introducing reactants. The performance of the oxidation catalyst streams on combustion turbines results in 90+ percent control of CO and above 85 to 90 percent control of formaldehyde. Similar emission reductions are expected for other HAP pollutants.

## VII. General Calculations

### A. Assumptions

- Operation schedule = 24 hr/day and 365 days/year (per applicant)
- All calculations and physical constants used are corrected to Standard Conditions as defined in District Rule 1020 Section 3.47
- The duct burner is not fired during the turbine startup or shutdown period, but does operate during all other operating modes
- Natural gas higher heating value = 1,000 Btu/scf
- Natural gas F-factor (adjusted to 60 °F) = 8,578 dscf/MMBtu (40 CFR 60 Appendix B)
- Maximum natural gas sulfur concentration = 0.75 gr-S/100 scf (BACT requirement and proposed by the applicant)

The applicant has proposed the following startup and shutdown provisions.

<b>Turbine Startup and Shutdown Daily Events</b>			
Daily # of Startups	Startup Duration (minutes/event)	Daily # of Shutdowns	Shutdown Duration (minutes/event)
2	22	2	10

<b>Turbine Startup and Shutdown Annual Events</b>			
Annual # of Startups	Startup Duration (minutes/event)	Annual # of Shutdowns	Shutdown Duration (minutes/event)
6	22	6	10

## B. Emission Factors

### Startup

Startup Emissions (22-minute duration)						
Pollutant	NO <sub>x</sub> (lb/event)	SO <sub>x</sub> (lb/event)	PM <sub>10</sub> (lb/event)	CO (lb/event)	VOC (lb/event)	NH <sub>3</sub> (lb/event)
Mass Emission Rate	1.6	0.053	0.423	79.3	0.5	0

### Shutdown

Shutdown Emissions (10-minute duration)						
Pollutant	NO <sub>x</sub> (lb/event)	SO <sub>x</sub> (lb/event)	PM <sub>10</sub> (lb/event)	CO (lb/event)	VOC (lb/event)	NH <sub>3</sub> (lb/event)
Mass Emission Rate	0.4	0.024	0.192	34.7	0.2	0

### Steady State

The following emission factors are after the CO catalyst and SCR catalyst based on 100% load.

Turbine + Duct Burner			
Pollutant	ppmvd @ 15% O <sub>2</sub>	lb/MMBtu	Source
NO <sub>x</sub>	2.5	0.00907	BACT Guideline 3.4.3 and Applicant Proposal
SO <sub>x</sub>	-	0.00214 <sup>(1)</sup>	BACT Guideline 3.4.3 and Applicant Proposal
PM <sub>10</sub>	-	0.017	Applicant Proposal
CO	6.0	0.0132	BACT Guideline 3.4.3 and Applicant Proposal
VOC	2.0	0.00252	BACT Guideline 3.4.3 and Applicant Proposal
NH <sub>3</sub>	10.0	-	Applicant Proposal

### Ammonia (NH<sub>3</sub>) from SCR

The proposed daily NH<sub>3</sub> emissions can be calculated as follows:

$$EF = \text{ppm} \times MW \times 1/379.5 \times ff \times [20.9 / (20.9 - O_2\%)]$$

<sup>(1)</sup> Fuel sulfur content limited to 0.75 grains/100 scf. The conversion of this value to lb/MMBtu can be performed using the following calculation: [(0.75 grains/100 scf) \* (1 scf/1,000 Btu) \* (1 lb/7,000 grains) \* (10<sup>6</sup> Btu/MMBtu) \* (1 lb-mol SO<sub>x</sub>/1 lb-mole S) \* (64 lb/1 lb-mol SO<sub>x</sub>) \* (1 lb-mol S/32 lb)] = 0.00214 lb/MMBtu

Where:

- ppm is the emission concentration in ppmvd @ 3% O<sub>2</sub>
- MW is the molecular weight of the pollutant (MW<sub>NH<sub>3</sub></sub> = 17 lb/lb-mol)
- 379.5 is the molar specific volume (lb/MMscf, at 60 °F)
- ff is the F-factor for natural gas/propane (8,578 scf/MMBtu, at 60 °F)
- O<sub>2</sub> is the stack oxygen content to which the emission concentrations are corrected (3%)

$$\begin{aligned} \text{EF (lb/MMBtu)} &= 10 \times 17 \times 1/379.5 \text{ (lb-mol/MMscf)} \times 8,578 \text{ (scf/MMBtu)} \times \\ &\quad [20.9 / (20.9 - 3.0)] \\ &= 0.0045 \text{ lb-NH}_3\text{/MMBtu} \end{aligned}$$

### C. Calculations

#### 1. Pre-Project Potential to Emit (PE1)

Since this is a new emissions unit, PE1 = 0 for all pollutants.

#### 2. Post-Project Potential to Emit (PE2)

##### Startup Emissions

Daily Startup Emissions (22-minutes/event)					
NO <sub>x</sub>	1.6	(lb/event)	x	2	(events/day) = 3.2 (lb/day)
SO <sub>x</sub>	0.053	(lb/event)	x	2	(events/day) = 0.1 (lb/day)
PM <sub>10</sub>	0.423	(lb/event)	x	2	(events/day) = 0.8 (lb/day)
CO	79.3	(lb/event)	x	2	(events/day) = 158.6 (lb/day)
VOC	0.5	(lb/event)	x	2	(events/day) = 1.0 (lb/day)
NH <sub>3</sub>	0	(lb/event)	x	2	(events/day) = 0.0 (lb/day)

Annual Startup Emissions (22-minutes/event)					
NO <sub>x</sub>	1.6	(lb/event)	x	6	(events/year) = 10 (lb/year)
SO <sub>x</sub>	0.053	(lb/event)	x	6	(events/year) = 0 (lb/year)
PM <sub>10</sub>	0.423	(lb/event)	x	6	(events/year) = 3 (lb/year)
CO	79.3	(lb/event)	x	6	(events/year) = 476 (lb/year)
VOC	0.5	(lb/event)	x	6	(events/year) = 3 (lb/year)
NH <sub>3</sub>	0	(lb/event)	x	6	(events/year) = 0 (lb/year)

Shutdown Emissions

<b>Daily Shutdown Emissions (10-minutes/event)</b>						
NO <sub>x</sub>	0.4	(lb/event)	x	2	(events/day)	= 0.8 (lb/day)
SO <sub>x</sub>	0.024	(lb/event)	x	2	(events/day)	= 0.0 (lb/day)
PM <sub>10</sub>	0.192	(lb/event)	x	2	(events/day)	= 0.4 (lb/day)
CO	34.7	(lb/event)	x	2	(events/day)	= 69.4 (lb/day)
VOC	0.2	(lb/event)	x	2	(events/day)	= 0.4 (lb/day)
NH <sub>3</sub>	0	(lb/event)	x	2	(events/day)	= 0.0 (lb/day)

<b>Annual Shutdown Emissions (10-minutes/event)</b>						
NO <sub>x</sub>	0.4	(lb/event)	x	6	(events/year)	= 2 (lb/year)
SO <sub>x</sub>	0.024	(lb/event)	x	6	(events/year)	= 0 (lb/year)
PM <sub>10</sub>	0.192	(lb/event)	x	6	(events/year)	= 1 (lb/year)
CO	34.7	(lb/event)	x	6	(events/year)	= 208 (lb/year)
VOC	0.2	(lb/event)	x	6	(events/year)	= 1 (lb/year)
NH <sub>3</sub>	0	(lb/event)	x	6	(events/year)	= 0 (lb/year)

Steady State (Turbine 67.9 MMBtu/hr + Duct Burner 57 MMBtu/hr = 124.9 MMBtu/hr)

It will be assumed the turbine will always be run in steady state mode with both the turbine and duct burner at maximum output. The only time the turbine will run without the duct burner is during start up and shut down.

**a. Hourly Post-Project Potential to Emit (PE2)**

<b>Hourly Steady State Emissions – Turbine + Duct Burner</b>						
NO <sub>x</sub>	0.00907	(lb/MMBtu)	x	124.9	(MMBtu/hr)	= 1.13 (lb/hour)
SO <sub>x</sub>	0.00214	(lb/MMBtu)	x	124.9	(MMBtu/hr)	= 0.27 (lb/hour)
PM <sub>10</sub>	0.017	(lb/MMBtu)	x	124.9	(MMBtu/hr)	= 2.12 (lb/hour)
CO	0.0132	(lb/MMBtu)	x	124.9	(MMBtu/hr)	= 1.65 (lb/hour)
VOC	0.00252	(lb/MMBtu)	x	124.9	(MMBtu/hr)	= 0.31 (lb/hour)
NH <sub>3</sub>	0.0045	(lb/MMBtu)	x	124.9	(MMBtu/hr)	= 0.56 (lb/hour)



**b. Daily Post-Project Potential to Emit (PE2)**

The turbine is assumed to be in startup or shutdown for 64 minutes per day (2 startups/day x 22 min/startup + 2 shutdowns/day x 10 min/shutdown). The emissions from the remaining 1,376 minutes/day (1,440 minutes/day – 64 minutes/day) are calculated in the table below.

<b>Daily Steady State Emissions – Turbine + Duct Burner</b>	
NO <sub>x</sub>	0.00907 (lb/MMBtu) x 124.9 (MMBtu/hr) x 1376/60 (hr/day) = 26.0 (lb/day)
SO <sub>x</sub>	0.00214 (lb/MMBtu) x 124.9 (MMBtu/hr) x 1376/60 (hr/day) = 6.1 (lb/day)
PM <sub>10</sub>	0.017 (lb/MMBtu) x 124.9 (MMBtu/hr) x 1376/60 (hr/day) = 48.7 (lb/day)
CO	0.0132 (lb/MMBtu) x 124.9 (MMBtu/hr) x 1376/60 (hr/day) = 37.8 (lb/day)
VOC	0.00252 (lb/MMBtu) x 124.9 (MMBtu/hr) x 1376/60 (hr/day) = 7.2 (lb/day)
NH <sub>3</sub>	0.0045 (lb/MMBtu) x 124.9 (MMBtu/hr) x 1376/60 (hr/day) = 12.9 (lb/day)

<b>Total Daily Emissions – Turbine + Duct Burner</b>				
	Startup	Shutdown	Steady State	Total
NO <sub>x</sub>	3.2 (lb/day)	+ 0.8 (lb/day)	+ 26.0 (lb/day)	= 30.0 (lb/day)
SO <sub>x</sub>	0.1 (lb/day)	+ 0.0 (lb/day)	+ 6.1 (lb/day)	= 6.2 (lb/day)
PM <sub>10</sub>	0.8 (lb/day)	+ 0.4 (lb/day)	+ 48.7 (lb/day)	= 49.9 (lb/day)
CO	158.6 (lb/day)	+ 69.4 (lb/day)	+ 37.8 (lb/day)	= 265.8 (lb/day)
VOC	1.0 (lb/day)	+ 0.4 (lb/day)	+ 7.2 (lb/day)	= 8.6 (lb/day)
NH <sub>3</sub>	0.0 (lb/day)	+ 0.0 (lb/day)	+ 12.9 (lb/day)	= 12.9 (lb/day)

**c. Annual Post-Project Potential to Emit (PE2)**

The turbine is assumed to be in startup or shutdown for 3.2 hours per year (6 startups/year x 22 min/startup + 6 shutdowns/year x 10 min/shutdown). The emissions from the remaining 8,756.8 hours/year (8,760 hours/year – 3.2 hours/year) are calculated in the table below.

<b>Annual Steady State Emissions – Turbine + Duct Burner</b>	
NO <sub>x</sub>	0.00907 (lb/MMBtu) x 124.9 (MMBtu/hr) x 8,756.8 (hr/year) = 9,920 (lb/year)
SO <sub>x</sub>	0.00214 (lb/MMBtu) x 124.9 (MMBtu/hr) x 8,756.8 (hr/year) = 2,341 (lb/year)
PM <sub>10</sub>	0.017 (lb/MMBtu) x 124.9 (MMBtu/hr) x 8,756.8 (hr/year) = 18,593 (lb/year)
CO	0.0132 (lb/MMBtu) x 124.9 (MMBtu/hr) x 8,756.8 (hr/year) = 14,437 (lb/year)
VOC	0.00252 (lb/MMBtu) x 124.9 (MMBtu/hr) x 8,756.8 (hr/year) = 2,756 (lb/year)
NH <sub>3</sub>	0.0045 (lb/MMBtu) x 124.9 (MMBtu/hr) x 8,756.8 (hr/year) = 4,922 (lb/year)

Total Annual Emissions – Turbine + Duct Burner											
	Startup			Shutdown			Steady State			Total	
NO <sub>x</sub>	10	(lb/year)	+	2	(lb/year)	+	9,920	(lb/year)	=	9,932	(lb/year)
SO <sub>x</sub>	0	(lb/year)	+	0	(lb/year)	+	2,341	(lb/year)	=	2,341	(lb/year)
PM <sub>10</sub>	3	(lb/year)	+	1	(lb/year)	+	18,593	(lb/year)	=	18,597	(lb/year)
CO	476	(lb/year)	+	208	(lb/year)	+	14,437	(lb/year)	=	15,121	(lb/year)
VOC	3	(lb/year)	+	1	(lb/year)	+	2,756	(lb/year)	=	2,760	(lb/year)
NH <sub>3</sub>	0	(lb/year)	+	0	(lb/year)	+	4,922	(lb/year)	=	4,922	(lb/year)

### 3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the Pre-Project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

The following values were taken from project S-1144247,

Pre-Project Stationary Source Potential to Emit [SSPE1] (lb/year)							
	NO <sub>x</sub>	SO <sub>x</sub>	PM <sub>10</sub>	PM <sub>2.5</sub>	CO	VOC	NH <sub>3</sub>
Pre-Project SSPE (SSPE1)	> 314,914	> 216,764	> 206,260	> 206,260	> 991,973	> 1,083,348	0

Note: PM<sub>2.5</sub> assumed to be equal to PM<sub>10</sub>

### 4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Post-Project Stationary Source Potential to Emit [SSPE2] (lb/year)							
Permit Unit	NO <sub>x</sub>	SO <sub>x</sub>	PM <sub>10</sub>	PM <sub>2.5</sub>	CO	VOC	NH <sub>3</sub>
SSPE1	> 314,914	> 216,764	> 206,260	> 206,260	> 991,973	> 1,083,348	0
S-1246-416-0	9,932	2,341	18,597	18,597	15,121	2,760	4,922
Post-Project SSPE (SSPE2)	> 324,846	> 219,105	> 224,857	> 224,857	> 1,007,094	> 1,086,108	4,922

Note: PM<sub>2.5</sub> assumed to be equal to PM<sub>10</sub>

## 5. Major Source Determination

### Rule 2201 Major Source Determination

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

<b>Rule 2201 Major Source Determination (lb/year)</b>						
	NO <sub>x</sub>	SO <sub>x</sub>	PM <sub>10</sub>	PM <sub>2.5</sub>	CO	VOC
Pre-Project SSPE (SSPE1)	> 314,914	> 216,764	> 206,260	> 206,260	> 991,973	> 1,083,348
Post Project SSPE (SSPE2)	> 324,846	> 219,105	> 224,857	> 224,857	> 1,007,094	> 1,086,108
Major Source Threshold	20,000	140,000	140,000	200,000	200,000	20,000
Major Source?	Yes	Yes	Yes	Yes	Yes	Yes

This source is an existing Major Source and will remain a Major Source.

### Rule 2410 Major Source Determination

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). Therefore the following PSD Major Source thresholds are applicable.

<b>PSD Major Source Determination (tons/year)</b>						
	NO <sub>2</sub>	VOC	SO <sub>2</sub>	CO	PM	PM <sub>10</sub>
Estimated Facility PE before Project Increase	> 157.5	> 541.7	> 108.4	> 496.0	> 103.1	> 103.1
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source ? (Y/N)	N	Y	N	Y	N	N

As shown above, the facility is an existing PSD major source for at least one pollutant.

## 6. Baseline Emissions (BE)

The BE calculation (in lbs/year) is performed pollutant-by-pollutant for each unit within the project, to calculate the QNEC and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = Pre-project Potential to Emit for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

Since this is a new emissions unit, BE = PE1 = 0 for all pollutants.

## 7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is a major source, the project's PE2 is compared to the SB 288 Major Modification Thresholds in the following table in order to determine if the SB 288 Major Modification calculation is required.

<b>SB 288 Major Modification Thresholds</b>			
Pollutant	Project PE2 (lb/year)	Threshold (lb/year)	SB 288 Major Modification Calculation Required?
NO <sub>x</sub>	9,932	50,000	No
SO <sub>x</sub>	2,341	80,000	No
PM <sub>10</sub>	18,597	30,000	No
VOC	2,760	50,000	No

Since none of the SB 288 Major Modification Thresholds are surpassed with this project, this project does not constitute an SB 288 Major Modification.

## 8. Federal Major Modification

District Rule 2201 states that major modifications are also federal major modifications, unless they qualify for either a "Less-Than-Significant Emissions Increase" exclusion or a "Plantwide Applicability Limit" (PAL) exclusion.

A Less-Than-Significant Emissions Increase exclusion is for an emissions increase for the project, or a Net Emissions Increase for the project (as defined in 40 CFR 51.165 (a)(2)(ii)(B) through (D), and (F)), that is not significant for a given regulated NSR pollutant, and therefore is not a federal major modification for that pollutant.

- To determine the post-project projected actual emissions from existing units, the provisions of 40 CFR 51.165 (a)(1)(xxviii) shall be used.
- To determine the pre-project baseline actual emissions, the provisions of 40 CFR 51.165 (a)(1)(xxxv)(A) through (D) shall be used.
- If the project is determined not to be a federal major modification pursuant to the provisions of 40 CFR 51.165 (a)(2)(ii)(B), but there is a reasonable possibility that the project may result in a significant emissions increase, the owner or operator shall comply with all of the provisions of 40 CFR 51.165 (a)(6) and (a)(7).
- Emissions increases calculated pursuant to this section are significant if they exceed the significance thresholds specified in the table below.

<b>Significant Threshold (lb/year)</b>	
Pollutant	Threshold (lb/year)
VOC	0
NO <sub>x</sub>	0
PM <sub>2.5</sub>	20,000 of direct PM <sub>2.5</sub> emissions or 80,000 of sulfur dioxide emissions or 80,000 of nitrogen oxide emissions
PM <sub>10</sub>	30,000
SO <sub>x</sub>	80,000

The Net Emissions Increases (NEI) for purposes of determination of a “Less-Than-Significant Emissions Increase” exclusion will be calculated below to determine if this project qualifies for such an exclusion.

The facility has submitted an ATC application for an identical cogeneration operation at the Pan Fee Lease (Section 2, T31S, R22E). The Pan Fee Lease is not contiguous or adjacent to the 21Z Lease (Section 21, T30S, R22E). The cogeneration operation in this project will be installed at the 21Z Lease. Therefore, these two projects are separate Federal stationary sources and can be processed as separate projects.

Net Emission Increase for New Units (NEI<sub>N</sub>)

Per 40 CFR 51.165 (a)(2)(ii)(D) for new emissions units in this project,

$$NEI_N = PE_{2N} - BAE$$

$$BAE = 0 \text{ for the new unit therefore } NEI_N = PE_{2N}$$

<b>Federal Major Modification Net Emissions Increase For New Units (NEI<sub>N</sub>)</b>					
Permit	NO <sub>x</sub> (lb/year)	SO <sub>x</sub> (lb/year)	PM <sub>10</sub> (lb/year)	PM <sub>2.5</sub> (lb/year)	VOC (lb/year)
S-1246-416-0	9,932	2,341	18,597	18,597	2,760

The NEI for this project is thus calculated as follows:

$$NEI = NEI_N$$

Net Emissions Increase (NEI)					
Permit	NO <sub>x</sub> (lb/year)	SO <sub>x</sub> (lb/year)	PM <sub>10</sub> (lb/year)	PM <sub>2.5</sub> (lb/year)	VOC (lb/year)
S-1246-416-0	9,932	2,341	18,597	18,597	2,760

Federal Major Modification Threshold			
Pollutant	NEI (lb/year)	Threshold (lb/year)	Federal Major Modification?
NO <sub>x</sub>	9,932	0	Yes
SO <sub>x</sub>	2,341	80,000	No
PM <sub>10</sub>	18,597	30,000	No
PM <sub>2.5</sub>	18,597	20,000 of direct PM <sub>2.5</sub> emissions	No
	3,117	80,000 of sulfur dioxide emissions	No
	9,932	80,000 of nitrogen oxide emissions	No
VOC	2,760	0	Yes

The NEI for this project will be greater than the federal Major Modification threshold for NO<sub>x</sub> and VOC. Therefore, this project does not qualify for a “Less-Than-Significant Emissions Increase” exclusion and is thus determined to be a Federal Major Modification for NO<sub>x</sub> and VOC.

#### 9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to pollutants for which the District is in attainment or for unclassified, pollutants. The pollutants addressed in the PSD applicability determination are listed as follows:

- NO<sub>2</sub> (as a primary pollutant)
- SO<sub>2</sub> (as a primary pollutant)
- CO
- PM
- PM<sub>10</sub>

The first step of this PSD evaluation consists of determining whether the facility is an existing PSD Major Source or not (See Section VII.C.5 of this document).

In the case the facility is an existing PSD Major Source, the second step of the PSD evaluation is to determine if the project results in a PSD significant increase.

In the case the facility is NOT an existing PSD Major Source but is an existing source, the second step of the PSD evaluation is to determine if the project, by itself, would be a PSD major source.

In the case the facility is new source, the second step of the PSD evaluation is to determine if this new facility will become a new PSD major Source as a result of the project and if so, to determine which pollutant will result in a PSD significant increase.

The facility has submitted an ATC application for an identical cogeneration operation at the Pan Fee Lease (Section 2, T31S, R22E). The Pan Fee Lease is not contiguous or adjacent to the 21Z Lease (Section 21, T30S, R22E). The cogeneration operation in this project will be installed at the 21Z Lease. Therefore, these two projects are separate Federal stationary sources and can be processed as separate projects.

**I. Potential to Emit for New or Modified Emission Units vs PSD Major Source Thresholds**

As a screening tool, the project potential to emit from all new and modified units is compared to the PSD major source threshold, and if total project potential to emit from all new and modified units is below this threshold, no further analysis will be needed.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). Therefore the following PSD Major Source thresholds are applicable.

<b>PSD Major Source Determination: Potential to Emit (tons/year)</b>						
	NO <sub>2</sub>	VOC	SO <sub>2</sub>	CO	PM	PM <sub>10</sub>
Total PE from New and Modified Units	5.0	1.4	1.2	7.6	9.3	9.3
PSD Major Source Thresholds	250	250	250	250	250	250
New PSD Major Source ? (Y/N)	N	N	N	N	N	N

As shown in the table above, the project emission increase, for all new and modified emission units, does not exceed any of the PSD major source thresholds. Therefore Rule 2410 is not applicable and no further discussion is required.

**10. Quarterly Net Emissions Change (QNEC)**

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

- QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
- PE2 = Post Project Potential to Emit for each emissions unit, lb/qtr.
- PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

<b>Quarterly NEC [QNEC]</b>			
	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NO <sub>x</sub>	2,483	0	2,483
SO <sub>x</sub>	585	0	585
PM <sub>10</sub>	4,649	0	4,649
CO	3,780	0	3,780
VOC	690	0	690

## **VIII. Compliance**

### **Rule 1080 Stack Monitoring**

This rule specifies that specific source types be equipped with CEMs. The proposed emission unit is not one of the listed source types. Additionally, this rule specifies performance, data reduction, recordkeeping, and reporting criteria for continuous emissions monitors.

Since the turbine will not be equipped with CEMS, the provisions of this rule are not applicable to this project.

### **Rule 1081 Source Sampling**

This rule requires adequate and safe facilities for using in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection. The following conditions will be listed on the permit to ensure compliance:

- The owner or operator shall be required to conform to the sampling facilities and testing procedures described in District Rule 1081 (as amended 12/16/93), Sections 3.0 and 6.1. [District Rule 1081]
- The District must be notified 30 days prior to any performance testing and a test plan shall be submitted for District approval 15 days prior to such testing. [District Rule 1081]
- Performance testing shall be witnessed or authorized by District personnel. Test results must be submitted to the District within 60 days of performance testing. [District Rule 1081]

Therefore, compliance with the requirements of this rule is expected.

### **Rule 1100 Equipment Breakdown**

This rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified. The following conditions will be listed on the permit to ensure compliance:

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]



- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

Therefore, compliance with the requirements of this rule is expected.

## **Rule 2201 New and Modified Stationary Source Review Rule**

### **A. Best Available Control Technology (BACT)**

#### **1. BACT Applicability**

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions\*:

- a. Any new emissions unit with a potential to emit exceeding two pounds per day,
- b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
- c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
- d. Any new or modified emissions unit, in a stationary source project, which results in a Major Modification.

\*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

#### **a. New emissions units – PE > 2 lb/day**

As seen in Section VII.C.2 above, the applicant is proposing to install a new natural gas-fired turbine with heat recovery with a PE greater than 2 lb/day for NO<sub>x</sub>, SO<sub>x</sub>, PM<sub>10</sub>, CO, and VOC. BACT is triggered for NO<sub>x</sub>, SO<sub>x</sub>, PM<sub>10</sub>, CO, and VOC since the PEs are greater than 2 lbs/day. However BACT is not triggered for NH<sub>3</sub> as ammonia emissions are intrinsic to the operation of the selective catalytic reduction (SCR) system, which is BACT for NO<sub>x</sub> emissions. Emissions from a control device that is determined by the District to be BACT are not subject to BACT.

<b>Natural Gas-Fired Turbine with Heat Recovery</b>		
<b>Pollutant</b>	<b>Daily PE2</b>	<b>BACT Triggered?</b>
NO <sub>x</sub>	26.0	Yes
SO <sub>x</sub>	6.2	Yes
PM <sub>10</sub>	48.7	Yes
CO	37.8	Yes
VOC	7.2	Yes
NH <sub>3</sub>	12.9	No*

\* BACT is not triggered for NH<sub>3</sub> since emissions from a control device that is determined to be BACT is not subject to BACT.

**b. Relocation of emissions units – PE > 2 lb/day**

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

**c. Modification of emissions units – AIPE > 2 lb/day**

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore BACT is not triggered.

**d. SB 288/Federal Major Modification**

As discussed in Section VII.C.7 and VII.C.8 above, this project does constitute a Federal Major Modification for NO<sub>x</sub> and VOC. Therefore BACT is triggered for NO<sub>x</sub> and VOC for all emission units in the project for which there is an emission increase.

**2. BACT Guideline**

BACT Guideline 3.4.3 applies to the natural gas-fired turbine in this project. [Gas Turbine with Heat Recovery (= > 3 MW and = < 10 MW)] (See Attachment A)

**3. Top-Down BACT Analysis**

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.

Pursuant to the attached Top-Down BACT Analysis (see Attachment A), BACT has been satisfied with the following:

- NO<sub>x</sub>: 2.5 ppmvd @ 15% O<sub>2</sub>, based on a three hour average (selective catalytic reduction)
- SO<sub>x</sub>: PUC-regulated natural gas or non-PUC-regulated natural gas with < 0.75 grains-S/100 dscf

PM<sub>10</sub>: Air inlet cooler, lube oil vent coalescer, and natural gas fuel  
 CO: 6.0 ppmv @ 15% O<sub>2</sub>, based on a three-hour average (catalytic oxidation or equal)  
 VOC: 2.0 ppmvd @ 15% O<sub>2</sub>, based on a three-hour average (catalytic oxidation)

**B. Offsets**

**1. Offset Applicability**

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

<b>Offset Determination (lb/year)</b>					
	NO <sub>x</sub>	SO <sub>x</sub>	PM <sub>10</sub>	CO	VOC
Post-Project SSPE (SSPE2)	> 324,846	> 219,105	> 224,857	> 1,007,094	> 1,086,108
Offset Threshold	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	Yes	Yes	Yes	Yes	Yes

**2. Quantity of Offsets Required**

As seen above, the facility is an existing Major Source for all pollutants and the SSPE2 is greater than the offset thresholds; therefore offset calculations will be required for this project.

The quantity of offsets in pounds per year is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) =  $(\Sigma[PE2 - BE] + ICCE) \times DOR$ , for all new or modified emissions units in the project,

Where,

PE2 = Post Project Potential to Emit, (lb/year)

BE = Baseline Emissions, (lb/year)

ICCE = Increase in Cargo Carrier Emissions, (lb/year)

DOR = Distance Offset Ratio

BE = Pre-project Potential to Emit for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, Located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE)

There are no increases in cargo carrier emissions; therefore offsets can be determined as follows:

$$\text{Offsets Required (lb/year)} = (\Sigma[\text{PE2} - \text{BE}]) \times \text{DOR}$$

#### CO Offset Calculations

CO offsets are triggered by CO emissions in excess of 200,000 lb/year for the facility.

However, pursuant to Section 4.6.1, "Emission Offsets shall not be required for the following: increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further 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 AERMOD air dispersion model, to determine if the CO emissions 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.

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 pursuant to Section 6.4.1.

<b>Offset Requirement</b>				
<b>Pollutant</b>	<b>NOx (lb/year)</b>	<b>SOx (lb/year)</b>	<b>PM<sub>10</sub> (lb/year)</b>	<b>VOC (lb/year)</b>
PE2	9,932	2,341	18,597	2,760
BE	0	0	0	0
PE2 – BE	9,932	2,341	18,597	2,760

The project is a Federal Major Modification for NO<sub>x</sub> and VOC emissions and therefore subject to a distance offset ratio of 1.5:1. In addition, a preliminary review of the proposed PM<sub>10</sub> and SO<sub>x</sub> emission reduction credits to be used for the proposed of this project shows that the location of those original reductions is more than 15 miles from the proposed equipment site. Therefore, PM<sub>10</sub> and SO<sub>x</sub> are subject to a distance offset ratio of 1.5:1.

Assuming an offset ratio of 1.5:1, the amount of ERCs that need to be withdrawn for this project are as follows:

<b>Offset Requirement x DOR (1.5)</b>				
Pollutant	NO <sub>x</sub> (lb/year)	SO <sub>x</sub> (lb/year)	PM <sub>10</sub> (lb/year)	VOC (lb/year)
PE2	14,898	3,512	27,896	4,140
BE	0	0	0	0
PE2 – BE	14,898	3,512	27,896	4,140

Calculating the appropriate quarterly emissions to be offset is as follows:

<b>Quarterly Offset Requirement x DOR (1.5)</b>				
Pollutant	1 <sup>st</sup> Qtr (lb/qtr)	2 <sup>nd</sup> Qtr (lb/qtr)	3 <sup>rd</sup> Qtr (lb/qtr)	4 <sup>th</sup> Qtr (lb/qtr)
NO <sub>x</sub>	3,724	3,724	3,725	3,725
SO <sub>x</sub>	878	878	878	878
PM <sub>10</sub>	6,974	6,974	6,974	6,974
VOC	1,035	1,035	1,035	1,035

The applicant has stated that the facility plans to use the following ERC certificates to offset the increases in emissions associated with this project. The certificates have available quarterly credits as follows:

<b>Proposed NO<sub>x</sub> ERC Certificates</b>				
ERC Certificate #	1 <sup>st</sup> Qtr (lb/qtr)	2 <sup>nd</sup> Qtr (lb/qtr)	3 <sup>rd</sup> Qtr (lb/qtr)	4 <sup>th</sup> Qtr (lb/qtr)
S-4514-2	4,332	1,450	4,332	1,569
S-4515-2	11,433	0	0	0
S-4516-2	239	239	239	239
S-4530-2	0	0	5,400	1,920
N-1302-2	0	0	2,915	0
N-1332-2	0	400	0	4,000
Total	16,004	2,089	12,886	7,728

<b>Proposed SO<sub>x</sub> ERC Certificates</b>				
ERC Certificate #	1 <sup>st</sup> Qtr (lb/qtr)	2 <sup>nd</sup> Qtr (lb/qtr)	3 <sup>rd</sup> Qtr (lb/qtr)	4 <sup>th</sup> Qtr (lb/qtr)
S-4508-5	4,606	5,021	4,825	6,146
N-1307-5	0	0	749	0
N-1309-5	749	0	0	693
C-1353-5	0	807	0	0
S-4533-5	342	284	342	398
S-4539-5	929	929	929	929
<b>Total</b>	<b>6,626</b>	<b>7,041</b>	<b>6,845</b>	<b>8,166</b>

<b>Proposed PM<sub>10</sub> ERC Certificates</b>				
ERC Certificate #	1 <sup>st</sup> Qtr (lb/qtr)	2 <sup>nd</sup> Qtr (lb/qtr)	3 <sup>rd</sup> Qtr (lb/qtr)	4 <sup>th</sup> Qtr (lb/qtr)
N-1206-4	0	6,024	9,030	2,588
N-1312-4	0	1,322	662	3,304
S-4510-4	0	0	0	508
S-4583-4	0	0	0	14,000
<b>Total</b>	<b>0</b>	<b>7,346</b>	<b>9,692</b>	<b>20,400</b>

<b>Proposed VOC ERC Certificates</b>				
ERC Certificate #	1 <sup>st</sup> Qtr (lb/qtr)	2 <sup>nd</sup> Qtr (lb/qtr)	3 <sup>rd</sup> Qtr (lb/qtr)	4 <sup>th</sup> Qtr (lb/qtr)
N-1202-1	66	66	66	66
N-1295-1	157	144	137	134
N-1296-1	0	0	20	0
N-1297-1	0	1,027	0	0
S-4500-1	8	1,433	8	8
S-4502-1	1,307	1,307	1,307	1,308
S-4504-1	284	0	0	0
<b>Total</b>	<b>1,822</b>	<b>3,977</b>	<b>1,538</b>	<b>1,516</b>

The applicant proposes to use SO<sub>x</sub> for PM<sub>10</sub> offsets. The District has established an interpollutant offset ratio (IOR) of 1.000:1 per draft Interpollutant Offset Ratio Policy (reference Policy APR 1430).

As seen above, the facility has sufficient credits to fully offset the quarterly emissions increases associated with this project.

Proposed Rule 2201 (offset) Conditions

- Prior to operating equipment under this Authority to Construct, permittee shall surrender NO<sub>x</sub> emission reduction credits for the following quantity of emissions: 1st quarter – 3,724 lb, 2nd quarter – 3,724 lb, 3rd quarter – 3,725 lb, and 4th quarter – 3,725 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201]

- Prior to operating equipment under this Authority to Construct, permittee shall surrender SOx emission reduction credits for the following quantity of emissions: 1st quarter – 878 lb, 2nd quarter – 878 lb, 3rd quarter – 878 lb, and 4th quarter – 878 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201]
- Prior to operating equipment under this Authority to Construct, permittee shall surrender PM10 emission reduction credits for the following quantity of emissions: 1st quarter – 6,974 lb, 2nd quarter – 6,974 lb, 3rd quarter – 6,974 lb, and 4th quarter – 6,974 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. SOx ERCs may be used to offset PM10 increases at an interpollutant ratio of 1.000 lb-SOx: 1.0 lb-PM10. [District Rule 2201]
- Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantity of emissions: 1st quarter – 1,035 lb, 2nd quarter – 1,035 lb, 3rd quarter – 1,035 lb, and 4th quarter – 1,035 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201]
- ERC Certificate Numbers S-4514-2, S-4515-2, S-4516-2, S-4530-2, N-1302-2, N-1332-2, S-4508-5, N-1307-5, N-1309-5, C-1353-5, S-4533-5, S-4539-5, N-1206-4, N-1312-4, S-4510-4, S-4583-4, N-1202-1, N-1295-1, N-1296-1, N-1297-1, S-4500-1, S-4502-1, S-4504-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201]

## **C. Public Notification**

### **1. Applicability**

Public noticing is required for:

- a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
- b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
- c. Any project which results in the offset thresholds being surpassed,
- d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant, and/or
- e. Any project which results in a Title V significant permit modification.

#### **a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications**

New Major Sources are new facilities, which are also Major Sources. Since this is not a new facility, public noticing is not required for this project for New Major Source purposes.

As demonstrated in VII.C.7 and VII.C.8, this project does constitute a Federal Major Modification for NO<sub>x</sub> and VOC emissions; therefore, public noticing for Federal Major Modification purposes is required.

**b. PE > 100 lb/day**

The PE2 for this new unit is compared to the daily PE Public Notice thresholds in the following table:

<b>PE &gt; 100 lb/day Public Notice Thresholds</b>			
Pollutant	PE2 (lb/day)	Public Notice Threshold	Public Notice Triggered?
NO <sub>x</sub>	30.0	100 lb/day	No
SO <sub>x</sub>	6.2	100 lb/day	No
PM <sub>10</sub>	49.9	100 lb/day	No
CO	265.8	100 lb/day	Yes
VOC	8.6	100 lb/day	No
NH <sub>3</sub>	12.9	100 lb/day	No

Therefore, public noticing for PE > 100 lb/day purposes is required.

**c. Offset Threshold**

The following table compares pollutant will trigger public noticing requirements. As seen the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

<b>Offset Threshold</b>				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO <sub>x</sub>	> 314,914	> 324,846	20,000 lb/year	No
SO <sub>x</sub>	> 216,764	> 219,105	54,750 lb/year	No
PM <sub>10</sub>	> 206,260	> 224,857	29,200 lb/year	No
CO	> 991,973	> 1,007,094	200,000 lb/year	No
VOC	> 1,083,348	> 1,086,108	20,000 lb/year	No

As detailed above, there were no thresholds surpassed with this project; therefore public noticing is not required for offset purposes.



**d. SSIPE > 20,000 lb/year**

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

<b>Stationary Source Increase in Permitted Emissions [SSIPE] – Public Notice</b>					
Pollutant	Project PE2 (lb/year)	Project PE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO <sub>x</sub>	9,932	0	9,932	20,000 lb/year	No
SO <sub>x</sub>	2,341	0	2,341	20,000 lb/year	No
PM <sub>10</sub>	18,597	0	18,597	20,000 lb/year	No
CO	15,121	0	15,121	20,000 lb/year	No
VOC	2,760	0	2,760	20,000 lb/year	No
NH <sub>3</sub>	4,922	0	4,922	20,000 lb/year	No

As demonstrated above, the SSIPEs for all pollutants were less than 20,000 lb/year; therefore public noticing for SSIPE purposes is not required.

**e. Title V Significant Permit Modification**

As shown in the Discussion of Rule 2520 below, this project constitutes a Title V Significant Modification. Therefore, public noticing for Title V Significant Modification is required for this project.

**2. Public Notice Action**

As discussed above, public noticing is required for this project for Federal Major Modification for NO<sub>x</sub> and VOC emissions, CO emissions in excess of 100 lb/day, and Title V Significant Permit Modification. Therefore, public notice documents will be submitted to the US Environmental Protection Agency (US EPA), California Air Resources Board (CARB), and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC permit for this equipment.

**D. Daily Emission Limits (DELs)**

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

### Proposed Rule 2201 (DEL) Conditions

- During startup of the unit, emissions shall not exceed any of the following limits: 1.6 lb-NO<sub>x</sub> (as NO<sub>2</sub>)/startup; 0.053 lb-SO<sub>x</sub> (as SO<sub>2</sub>)/startup; 0.423 lb-PM<sub>10</sub>/startup; 79.3 lb-CO/startup; or 0.5 lb-VOC(as methane)/startup. [District Rule 2201]
- During shutdown of the unit, emissions shall not exceed any of the following limits: 0.4 lb-NO<sub>x</sub> (as NO<sub>2</sub>)/shutdown; 0.024 lb-SO<sub>x</sub> (as SO<sub>2</sub>)/shutdown; 0.192 lb-PM<sub>10</sub>/startup; 34.7 lb-CO/shutdown; or 0.2 lb-VOC (as methane)/shutdown. [District Rule 2201]
- NO<sub>x</sub>, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NO<sub>x</sub> (as NO<sub>2</sub>) - 2.5 ppmvd @ 15% O<sub>2</sub> or 1.13 lb/hr; CO - 6.0 ppmvd @ 15% O<sub>2</sub> or 1.65 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O<sub>2</sub> or 0.31 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]
- PM<sub>10</sub> emissions from this unit (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 2.12 lb/hr or 0.017 lb/MMBtu. [District Rule 2201]
- The turbine and duct burner shall be fired on PUC-quality natural gas and/or ethane-rich natural gas and the natural gas shall have a total sulfur content of less than or equal to 0.75 gr/100 scf. [District Rules 2201 and 4801 and 40 CFR 60.4330]
- The ammonia slip (NH<sub>3</sub>) emissions (with duct burner firing) shall not exceed either of the following limits: 0.56 lb/hr or 10.0 ppmvd @15% O<sub>2</sub> (based on a 24 hour rolling average). [District Rules 2201 and 4102]

## **E. Compliance Assurance**

### **1. Source Testing**

Pursuant to District Policy APR 1705, source testing is required to demonstrate compliance with Rule 2201.

The following conditions will be placed on the permit to ensure compliance with the assumptions made for Rule 2201. Source testing will be required within 60 days of initial start-up.

- Performance testing to measure the NO<sub>x</sub> (ppmvd), CO (ppmvd), VOC (ppmvd), and NH<sub>3</sub> (ppmvd) emissions shall be conducted within 60 days of startup and at least once every twelve months thereafter. [District Rules 2201, 4102, and 4703 and 40 CFR 60.4400(a)]
- Performance testing to measure the PM<sub>10</sub> emissions (lb/hr) shall be conducted within 60 days of startup. [District Rule 2201]
- NO<sub>x</sub> emissions (referenced as NO<sub>2</sub>) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, and 4703 and 40 CFR 60.4400]

- VOC emissions (referenced as methane) shall be determined using EPA Method 18 or EPA Method 25. [District Rules 1081 and 2201]
- CO emissions shall be determined using EPA Method 10 or EPA Method 10B. [District Rule 1081, 2201, and 4703]
- PM10 emissions shall be determined using EPA Methods 201 and 202, or EPA Methods 201A and 202, or CARB Method 501 in conjunction with CARB Method 5. [District Rules 1081 and 2201]
- Ammonia (NH<sub>3</sub>) emissions shall be determined using BAAQMD Method ST-1B. [District Rules 1081, 2201, and 4102]

## 2. Monitoring

The following conditions will be listed on the permit to ensure compliance with the assumptions made for Rule 2201.

- During initial performance testing, the ammonia injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit (with the duct burner operating). The minimum ammonia injection rate(s) demonstrated during the initial performance test to result in compliance with the NO<sub>x</sub> emission limits shall be imposed as a condition in the Permit to Operate. [District Rules 2201 and 4703]
- If the ammonia injection rate is less than the minimum ammonia injection rate demonstrated during the initial compliance test, the permittee shall return the ammonia injection rate above the minimum ammonia injection rate established during compliance testing as soon as possible, but no longer than 8 hours after detection. If the ammonia injection rate is not returned above the minimum ammonia injection rate established during compliance testing within 8 hours, the permittee shall notify the District within the following 1 hour and conduct a source test within 60 days of the first exceedance to demonstrate compliance with the applicable emission limits at the reduced ammonia injection rate. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4703]
- The permittee shall monitor and record the stack concentration of NO<sub>x</sub> (as NO<sub>2</sub>), CO, and O<sub>2</sub> weekly. If compliance with the NO<sub>x</sub> and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation (i.e. the unit need not be started solely to perform monitoring). Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703]

- If the NO<sub>x</sub> and/or CO concentrations, as measured by the permittee with a portable analyzer, exceed the permitted emission limits, the permittee shall notify the District and return the NO<sub>x</sub> and CO concentrations to the permitted emission limits as soon as possible but no longer than eight (8) hours after detection. If the permittee's portable analyzer readings continue to exceed the permitted emissions limits after eight (8) hours, the permittee shall notify the District within the following one (1) hour, and conduct a certified source test within 60 days to demonstrate compliance with the permitted emissions limits. In lieu of conducting a source test, the permittee may stipulate that a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4703]
- Compliance with ammonia emission limit shall be demonstrated utilizing one of the following procedures: 1) The permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. 2) The permittee may utilize a District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O<sub>2</sub>. The permittee shall submit a detailed calculation protocol or monitoring plan for District Approval at least 60 days prior to the commencement of operation. [District Rules 2201 and 4102]

### **3. Recordkeeping**

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The following conditions will be listed on the permit to ensure compliance:

- The permittee shall maintain a record of the cumulative 12 month rolling NO<sub>x</sub>, CO, VOC, SO<sub>x</sub>, PM<sub>10</sub>, and NH<sub>3</sub> emissions total, in lb/year, from this unit. These records shall be updated at the end of each month. [District Rule 2201]
- The permittee shall maintain a daily record of the ammonia injection rate and SCR catalyst inlet temperature. [District Rule 2201]
- The operator shall demonstrate compliance with the fuel sulfur content limit of 0.75 grains of sulfur compounds (as S) per 100 dry scf of natural gas at least once per week. Once compliance is demonstrated for eight consecutive weeks, the frequency for demonstrating compliance with the fuel sulfur content may be reduced to once every calendar quarter. If a quarterly determination shows a violation of the sulfur content limit, then weekly demonstrations shall resume and continue until eight consecutive demonstrations show compliance. Once compliance is shown on eight consecutive weekly determinations, then determinations may return to quarterly. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

- All records shall be retained for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070, 2201, and 4703]

#### **4. Reporting**

No reporting is required to demonstrate compliance with Rule 2201.

#### **F. Ambient Air Quality Analysis (AAQA)**

An AAQA shall be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis. Refer to Attachment D of this document for the AAQA summary sheet.

The proposed location is in an attainment area for NO<sub>x</sub>, CO, and SO<sub>x</sub>. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO<sub>x</sub>, CO, or SO<sub>x</sub>.

The proposed location is in a non-attainment area for the state's PM<sub>10</sub> as well as federal and state PM<sub>2.5</sub> thresholds. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for PM<sub>10</sub> and PM<sub>2.5</sub>.

#### **G. Compliance Certification**

Section 4.15.2 of this Rule requires the owner of a new Major Source or a source undergoing a Title I Modification to demonstrate to the satisfaction of the District that all other Major Sources owned by such person and operating in California are in compliance or are on a schedule for compliance with all applicable emission limitations and standards. As discussed in Section VIII above, this facility is a new major source and this project does constitute a Title I modification, therefore this requirement is applicable. The facility's compliance certification is included in Attachment B.

#### **H. Alternate Siting Analysis**

The current project occurs at an existing facility. The applicant proposes to install a cogeneration operation.

Since the project will provide power to be used at the same location, the existing site will result in the least possible impact from the project. Alternative sites would involve the relocation and/or construction of various support structures on a much greater scale, and would therefore result in a much greater impact.

### **Rule 2410 Prevention of Significant Deterioration**

The prevention of significant deterioration (PSD) program is a construction permitting program for new major stationary sources and major modifications to existing major stationary sources located in areas classified as attainment or in areas that are unclassifiable for any criteria air pollutant.

As demonstrated above, this project is not subject to the requirements of Rule 2410 due to a significant emission increase and no further discussion is required.

### **Rule 2520 Federally Mandated Operating Permits**

This facility is subject to this Rule, and has received their Title V Operating Permit. Section 3.29 defines a significant permit modification as a “permit amendment that does not qualify as a minor permit modification or administrative amendment.”

Section 3.20.5 states that a minor permit modification is a permit modification that does not meet the definition of modification as given in Section 111 or Section 112 of the Federal Clean Air Act. Since this project is a Title I modification (i.e. Federal Major Modification), the proposed project is considered to be a modification under the Federal Clean Air Act. As a result, the proposed project constitutes a Significant Modification to the Title V Permit pursuant to Section 3.29.

As discussed above, the facility has applied for a Certificate of Conformity (COC) (see Attachment C); therefore, the facility must apply to modify their Title V permit with an administrative amendment, prior to operating with the proposed modifications. Continued compliance with this rule is expected. The facility shall not implement the changes requested until the final permit is issued.

### **Rule 2540 Acid Rain Program**

Pursuant to CFR 40 Section 72.7, the acid rain program standards apply to any new utility that serves one or more generators with a total nameplate capacity of 25 MWe or more and burns only fuel with a sulfur content of 0.05 percent or less by weight. The nameplate rating for the proposed unit is 5.67 MWe. Thus, this unit is not subject to the Part 72 Acid Rain Program requirements and an application for an acid rain permit is not required.

### **Rule 4001 New Source Performance Standards (NSPS)**

#### **40 CFR 60 – Subpart GG – Standards of Performance for Stationary Gas Turbines**

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 October 3, 1977. The proposed turbine is new. Therefore, the proposed turbine meets the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(a), states that this subpart applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules (10 MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005. The proposed turbine is new. Therefore, the proposed turbine also meets the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG. As discussed above, 40 CFR 60 Subpart KKKK is applicable to the proposed turbine. Therefore, the turbine is exempt from the requirements of 40 CFR 60 Subpart GG.

#### **40 CFR 60 – Subpart KKKK – Standards of Performance for Stationary Combustion Turbines**

40 CFR Part 60 Subpart KKKK applies to all stationary combustion turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. The proposed gas turbine involved in this project has a rating of 67.9 MMBtu/hr and will be installed after February 18, 2005. Therefore, this subpart applies to the gas turbine.

Subpart KKKK established requirements for nitrogen oxide (NO<sub>x</sub>) and sulfur dioxide (SO<sub>x</sub>) emissions.

#### **Section 60.4320 - Standards for Nitrogen Oxides**

Paragraph (a) states that NO<sub>x</sub> emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO<sub>x</sub>. Table 1 states that new turbines firing natural gas with a combustion turbine heat input at peak load of greater than 850 MMBtu/hr shall meet a NO<sub>x</sub> emissions limit of 15 ppmvd @ 15% O<sub>2</sub> or 54 ng/J of useful output (0.43 lb/MWh).

The facility is proposing a NO<sub>x</sub> emission concentration limit of 2.5 ppmvd @ 15% O<sub>2</sub> for the turbine. Therefore, the proposed turbine will be operating in compliance with the NO<sub>x</sub> emission requirements of this subpart. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- NO<sub>x</sub>, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NO<sub>x</sub> (as NO<sub>2</sub>) - 2.5 ppmvd @ 15% O<sub>2</sub> or 1.13 lb/hr; CO - 6.0 ppmvd @ 15% O<sub>2</sub> or 1.65 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O<sub>2</sub> or 0.31 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]

Section 60.4330 - Standards for Sulfur Dioxide

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following:

- (1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO<sub>2</sub> in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh)) gross output;  
or
- (2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO<sub>2</sub>/J (0.060 lb SO<sub>2</sub>/MMBtu) heat input.

The facility is proposing to burn natural gas fuel in the turbine with a maximum sulfur content of 0.75 grain/100 scf (0.00214 lb/MMBtu). Therefore, the proposed system will be operating in compliance with the SO<sub>x</sub> emission requirements of this section. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- The turbine and duct burner shall be fired on PUC-quality natural gas and/or ethane-rich natural gas and the natural gas shall have a total sulfur content of less than or equal to 0.75 gr/100 scf. [District Rules 2201 and 4801 and 40 CFR 60.4330]

Section 60.4335 – NO<sub>x</sub> Compliance Demonstration, with Water or Steam Injection

Paragraph (a) states that when a turbine is using water or steam injection to reduce NO<sub>x</sub> emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

Paragraph (b) states that alternatively, an operator may use continuous emission monitoring, as follows:

- (1) Install, certify, maintain and operate a continuous emissions monitoring system (CEMS) consisting of a NO<sub>x</sub> monitor and a diluent gas (oxygen (O<sub>2</sub>) or carbon dioxide (CO<sub>2</sub>)) monitor, to determine hourly NO<sub>x</sub> emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and
- (2) For units complying with the output-based standard, install, calibrate, maintain and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and
- (3) For units complying with the output based standard, install, calibrate, maintain and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and
- (4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).



The turbine does not utilize water or steam injection. Therefore, the requirements of this section are not applicable to this project.

#### Section 60.4340 – NO<sub>x</sub> Compliance Demonstration, without Water or Steam Injection

Paragraph (a) states if you are not using water or steam injection to control NO<sub>x</sub> emissions, you must perform annual performance tests in accordance with Section 60.4400 to demonstrate continuous compliance. If the NO<sub>x</sub> emission result from the performance test is less than or equal to 75 percent of the NO<sub>x</sub> emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO<sub>x</sub> emission limit for the turbine, you must resume annual performance tests.

Paragraph (b) states as an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems: (1) Continuous emission monitoring as described in Sections 60.4335(b) and 60.4345, or (2) Continuous parameter monitoring as follows: (i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO<sub>x</sub> formation characteristics, and you must monitor these parameters continuously. (ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO<sub>x</sub> mode. (iii) For any turbine that uses SCR to reduce NO<sub>x</sub> emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls. (iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO<sub>x</sub> emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in § 75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in § 75.19(c)(1)(iv)(H).

The following condition will be listed on the permits to ensure compliance with the requirements of this section:

- Performance testing to measure the NO<sub>x</sub> (ppmvd), CO (ppmvd), VOC (ppmvd), and NH<sub>3</sub> (ppmvd) emissions shall be conducted within 60 days of startup and at least once every twelve months thereafter. [District Rules 2201 and 4703 and 40 CFR 60.4340]

#### Section 60.4345 – CEMS Equipment Requirements

Paragraph (a) states that each NO<sub>x</sub> diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO<sub>x</sub> diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the NO<sub>x</sub> monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO<sub>x</sub> emission rate for the hour.

Paragraph (c) states that each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

The facility will not install and operate a NO<sub>x</sub> CEMS in accordance with the requirements of this section. Therefore, the requirements of this section are not applicable to this project.

#### Section 60.4350 – CEMS Data and Excess NO<sub>x</sub> Emissions

Section 60.4350 states that for purposes of identifying excess emissions:

- (a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).
- (b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO<sub>x</sub> and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO<sub>x</sub> emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O<sub>2</sub> concentration exceeds 19.0 percent O<sub>2</sub> (or the hourly average CO<sub>2</sub> concentration is less than 1.0 percent CO<sub>2</sub>), a diluent cap value of 19.0 percent O<sub>2</sub> or 1.0 percent CO<sub>2</sub> (as applicable) may be used in the emission calculations.
- (c) Correction of measured NO<sub>x</sub> concentrations to 15 percent O<sub>2</sub> is not allowed.
- (d) If you have installed and certified a NO<sub>x</sub> diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO<sub>x</sub> emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

The facility will not install and operate a NO<sub>x</sub> CEMS in accordance with the requirements of this section. Therefore, the requirements of this section are not applicable to this project.

#### Section 60.4355 – Parameter Monitoring Plan

This section sets forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO<sub>x</sub> emissions.

As discussed above, the facility is proposing to perform annual source testing. Therefore, the requirements of this section are not applicable.

#### Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO<sub>2</sub>/J (0.060 lb SO<sub>2</sub>/MMBtu) heat input for units located in continental areas and 180 ng SO<sub>2</sub>/J (0.42 lb SO<sub>2</sub>/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

- (a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO<sub>2</sub>/J (0.060 lb SO<sub>2</sub>/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO<sub>2</sub>/J (0.42 lb SO<sub>2</sub>/MMBtu) heat input for noncontinental areas; or

- (b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO<sub>2</sub>/J (0.060 lb SO<sub>2</sub>/MMBtu) heat input for continental areas or 180 ng SO<sub>2</sub>/J (0.42 lb SO<sub>2</sub>/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

Linn Operating is proposing to operate these turbines on natural gas that has a maximum sulfur content of 0.75 grains/100 scf. Depending on the source of the natural gas used in these units, the facility may be able to demonstrate compliance by providing a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates that the natural gas sulfur content is less than or equal to 0.75 grains/100 scf. If that option cannot be met, Linn Operating will be required to physically monitor the sulfur content be incorporated into their permit.

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

- (a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to Part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).
- (b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.
- (c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

Linn Operating is proposing a custom monitoring schedule. The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every calendar quarter. If any quarterly monitoring period shows an exceedance, weekly monitoring shall resume. Linn Operating is proposing to follow this same pre-approved fuel sulfur content monitoring scheme for these turbines. The following condition will ensure continued compliance with the requirements of this section:

- The operator shall demonstrate compliance with the fuel sulfur content limit of 0.75 grains of sulfur compounds (as S) per 100 dry scf of natural gas at least once per week. Once compliance is demonstrated for eight consecutive weeks, the frequency for demonstrating compliance with the fuel sulfur content may be reduced to once every calendar quarter. If a quarterly determination shows a violation of the sulfur content limit, then weekly demonstrations shall resume and continue until eight consecutive demonstrations show compliance. Once compliance is shown on eight consecutive weekly determinations, then determinations may return to quarterly. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

#### Section 60.4380 – Excess NO<sub>x</sub> Emissions

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios.

As discussed above, the facility is not proposing to monitor parameters associated with water or steam to fuel ratios to predict what the NO<sub>x</sub> emissions from the turbines will be. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEM's:

- (1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO<sub>x</sub> emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO<sub>x</sub> emission rate" is the arithmetic average of the average NO<sub>x</sub> emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO<sub>x</sub> emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO<sub>x</sub> emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO<sub>x</sub> emission rate" is the arithmetic average of all hourly NO<sub>x</sub> emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO<sub>x</sub> emissions rates for the preceding 30 unit operating days if a valid NO<sub>x</sub> emission rate is obtained for at least 75 percent of all operating hours.
- (2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO<sub>x</sub> concentration, CO<sub>2</sub> or O<sub>2</sub> concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.
- (3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the NO<sub>x</sub> emission controls.

The facility is not proposing to use CEMs or monitor combustion parameters that document proper operation of the NO<sub>x</sub> emission controls. Therefore, the requirements of this section are not applicable.

#### Section 60.4385 – Excess SO<sub>x</sub> Emissions

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

- (a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.
- (b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.
- (c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

The following condition will ensure continued compliance with the requirements of this section:

- Excess SO<sub>x</sub> emissions is each unit operating hour including in the period beginning on the date and hour of any sample for which the fuel sulfur content exceeds the applicable limits listed in this permit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit. Monitoring downtime for SO<sub>x</sub> begins when a sample is not taken by its due date. A period of monitor downtime for SO<sub>x</sub> also begins on the date and hour of a required sample, if invalid results are obtained. A period of SO<sub>x</sub> monitoring downtime ends on the date and hour of the next valid sample. [40 CFR 60.4385(a) and (c)]

### Sections 60.4375 and 60.4395 – Reporting

These sections establish the reporting requirements for each turbine. These requirements include methods and procedures for submitting reports of monitoring parameters, annual performance tests, excess emissions and periods of monitor downtime. The facility is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. Therefore, the proposed turbine will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall submit a written report of excess emissions and monitoring downtime to the APCO. The report is due on the 30<sup>th</sup> day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Applicable time and date of each period during monitor downtime; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375 and 60.4395]

### Section 60.4400 – NO<sub>x</sub> Performance Testing

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Subsequent NO<sub>x</sub> performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set forth the requirements for the methods that are to be used during source testing.

The facility will be required to source test the exhaust of this turbine within 60 days of initial startup and at least once every 12 months thereafter. The facility will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). Therefore, the proposed turbine will be operating in compliance with the requirements of this section. The following conditions will be listed on the permit to ensure compliance with the requirements of this section:

- Performance testing to measure the NO<sub>x</sub> (ppmvd), CO (ppmvd), VOC (ppmvd), and NH<sub>3</sub> (ppmvd) emissions shall be conducted within 60 days of startup and at least once every twelve months thereafter. [District Rules 2201 and 4703 and 40 CFR 60.4340 and 60.4400]
- NO<sub>x</sub> emissions (referenced as NO<sub>2</sub>) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, and 4703 and 40 CFR 60.4400]

### Section 60.4405 – Initial CEMS Relative Accuracy Testing

Section 60.4405 states that if you elect to install and certify a NO<sub>x</sub>-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d).

The facility will not install and operate a NO<sub>x</sub> CEMS in accordance with the requirements of this section. Therefore, the requirements of this section are not applicable to this project.

### Section 60.4410 – Parameter Monitoring Ranges

Section 60.4410 sets forth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO<sub>x</sub> emission controls.

As discussed above, the facility is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable.

### Section 60.4415 – SO<sub>x</sub> Performance Testing

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent SO<sub>2</sub> performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

- (i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or
- (ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

Linn Operating is proposing to periodically determine the sulfur content of the fuel combusted in each of these units when valid purchase contracts, tariff sheets or transportation contract that show the sulfur content is less than 0.75 grains/100 scf are not available. The sulfur content will be determined using the methods specified above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:



- The sulfur fuel content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. If compliance is being demonstrated through fuel sulfur content testing, the testing shall occur at a location after all fuel sources are combined prior to combustion, or by performing mass balance calculations based on testing the sulfur content and volume of each fuel source. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the SO<sub>2</sub> concentration in the exhaust stream. GWF Henrietta is not proposing to measure the SO<sub>2</sub> in the exhaust stream of these turbines. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

### Conclusion

Conditions will be incorporated into the permits in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart KKKK is expected.

## **Rule 4002 National Emission Standards for Hazardous Air Pollutants (NESHAPs)**

### **40 CFR 63 – Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines**

Section 63.6080 states Subpart YYYY establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations.

Section 63.6085 states you are subject to this subpart if you own or operate a stationary combustion turbine located at a major source of HAP emissions.

- (a) Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function, although it may be mounted on a vehicle for portability or transportability. Stationary combustion turbines covered by this subpart include simple cycle stationary combustion turbines, regenerative/recuperative cycle stationary combustion turbines, cogeneration cycle stationary combustion turbines, and combined cycle stationary combustion turbines. Stationary combustion turbines subject to this subpart do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

- (b) A major source of HAP emissions is a contiguous site under common control that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

This stationary source has the potential to emit of any single HAP less than 10 tons per year and combination of HAPs less than 25 tons per year. Therefore, the requirements of this subpart are not applicable to this project.

#### **Rule 4101 Visible Emissions**

Rule 4101 states that 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.

The following condition will be listed on the permit to ensure compliance:

- 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]

#### **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. Therefore, compliance with this rule is expected and the following condition will be listed on the permit to ensure compliance:

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

#### **California Health & Safety Code 41700 (Health Risk Assessment)**

District Policy APR 1905 – Risk Management Policy for Permitting New and Modified Sources specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (Attachment D), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.

The cancer risk for this project is shown below:

HRA Summary		
Unit	Cancer Risk	T-BACT Required
S-1246-416-0	0.0024 per million	No

### Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 10 in a million). As outlined by the HRA Summary in Attachment D of this report, the emissions increases for this project was determined to be less than significant.

### Rule 4201 Particulate Matter Concentration

Section 3.0 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 calculations were performed for each piece of equipment by the following equation:

F-Factor for natural gas: 8,578 dscf/MMBtu  
 PM<sub>10</sub> Emission Factor: 0.017 lb-PM<sub>10</sub>/MMBtu  
 Percentage of PM as PM<sub>10</sub> in Exhaust: 100%

$$GL = \left( \frac{0.017 \text{ lb-PM}}{\text{MMBtu}} \times \frac{7,000 \text{ grain}}{\text{lb-PM}} \right) / \left( \frac{8,578 \text{ ft}^3}{\text{MMBtu}} \right)$$

$$GL = 0.014 \text{ grain/dscf} < 0.1 \text{ grain/dscf}$$

Since the particulate matter concentration is  $\leq 0.1$  grains per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the permit to ensure compliance:

- Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

**Rule 4202 Particulate Matter Emission Rate**

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr.

Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to the proposed equipment.

**Rule 4301 Fuel Burning Equipment**

This rule specifies maximum emission rates in lb/hr for SO<sub>2</sub>, NO<sub>2</sub>, and combustion contaminants (defined as total PM in Rule 1020). This rule also limits combustion contaminants to ≤ 0.1 gr/scf. According to AP 42 (Table 1.4-2, footnote c), all PM emissions from natural gas combustion are less than 1 μm in diameter. As shown below, the unit's maximum hourly emission rates are below the Rule 4301 limits.

<b>District Rule 4301 Limits</b>			
Unit	NO <sub>2</sub>	Total PM	SO <sub>2</sub>
S-1246-416-0	1.25	2.08	0.27
Rule 4301 Limit	140 lb/hr	10 lb/hr	200 lb/hr

As shown above, compliance with this rule is expected.

**Rule 4305 Boilers, Steam Generators, and Process Heaters (Phase 2)**

This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a rated heat input greater than 5 million Btu per hour.

Rule 4305 Section 4.1.4 exempts unfired and fired waste heat recovery boilers from the requirements of this rule provided that the waste heat recovery boiler is used to recover or augment heat from the exhaust of combustion turbines or internal combustion engines. The duct burner and heat recovery steam generator are a fired waste heat recovery boiler used to augment the heat from the exhaust of the Solar Turbines Inc. turbine. Therefore, the requirements of Rule 4305 are not applicable to the duct burner.

**Rule 4306 Boilers, Steam Generators, and Process Heaters (Phase 3)**

This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a rated heat input greater than 5 million Btu per hour.

Rule 4306 Section 4.1.4 exempts unfired and fired waste heat recovery boilers from the requirements of this rule provided that the waste heat recovery boiler is used to recover or augment heat from the exhaust of combustion turbines or internal combustion engines. The duct burner and heat recovery steam generator are a fired waste heat recovery boiler used to augment the heat from the exhaust of the Solar Turbines Inc. turbine. Therefore, the requirements of Rule 4306 are not applicable to the duct burner.

### **Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr**

This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a rated heat input greater than 5 million Btu per hour.

Rule 4320 Section 4.1.4 exempts unfired and fired waste heat recovery boilers from the requirements of this rule provided that the waste heat recovery boiler is used to recover or augment heat from the exhaust of combustion turbines or internal combustion engines. The duct burner and heat recovery steam generator are a fired waste heat recovery boiler used to augment the heat from the exhaust of the Solar Turbines Inc. turbine. Therefore, the requirements of Rule 4320 are not applicable to the duct burner.

### **Rule 4703 Stationary Gas Turbines**

Rule 4703 limits NO<sub>x</sub> and CO emissions from stationary gas turbines with ratings of greater than 0.3 megawatts and/or maximum heat input ratings of more than 3,000,000 Btu/hr. The facility proposes to install one 5.67 MW gas turbine, therefore this rule applies.

#### Section 5.1 – NO<sub>x</sub> Emission Requirements

Sections 5.1.1 and 5.1.2 specify the Tier 1 and Tier 2 NO<sub>x</sub> compliance limits. As discussed below, Linn Operating is proposing to operate this turbine in compliance with the Tier 3 NO<sub>x</sub> emission limits specified in section 5.1.3. The Tier 3 NO<sub>x</sub> emission limits are more stringent than the Tier 1 and Tier 2 NO<sub>x</sub> emission limits. Therefore, compliance with the Tier 1 and Tier 2 NO<sub>x</sub> emission limits will be demonstrated with compliance of the Tier 3 NO<sub>x</sub> emission limits and no further discussion is required.

Section 5.1.3 (Tier 3) of this rule limits the NO<sub>x</sub> emissions from natural gas fired stationary gas turbine systems rated between 3 MW to 10 MW and allowed to operation for more than 877 hours per year to 5 ppmv @ 15% O<sub>2</sub>. As discussed above, the proposed turbine will be limited to 2.5 ppmv @ 15% O<sub>2</sub>, therefore compliance with this section is expected. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- NO<sub>x</sub>, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NO<sub>x</sub> (as NO<sub>2</sub>) - 2.5 ppmvd @ 15% O<sub>2</sub> or 1.13 lb/hr; CO - 6.0 ppmvd @ 15% O<sub>2</sub> or 1.65 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O<sub>2</sub> or 0.31 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]

## Section 5.2 – CO Emission Requirements

Per Table 5-4 of section 5.2, the CO emissions concentration from the proposed turbine must be less than 200 ppmvd @ 15% O<sub>2</sub>. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. However, District practice is to have an applicant demonstrate compliance with the CO emissions on a turbine with three hour averaging periods. Therefore, compliance with the CO emission limit shall be demonstrated by an average over a three hour period.

The facility is proposing a CO emission concentration limit of 6.0 ppmvd @ 15% O<sub>2</sub> and will demonstrate compliance using three hour averaging periods. Therefore, the proposed turbine will be operating the turbine in compliance with the CO emission requirements of this rule. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- NO<sub>x</sub>, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NO<sub>x</sub> (as NO<sub>2</sub>) - 2.5 ppmvd @ 15% O<sub>2</sub> or 1.13 lb/hr; CO - 6.0 ppmvd @ 15% O<sub>2</sub> or 1.65 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O<sub>2</sub> or 0.31 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]

## Section 5.3 – Startup and Shutdown Requirements

This section states that the emission limit requirements of Sections 5.1.1, 5.1.2 or 5.2 shall not apply during startup, shutdown, or a reduced load period provided an operator complies with the requirements specified below:

- The duration of each startup or each shutdown shall not exceed two hours, and the duration of each reduced load period shall not exceed one hour, except as provided below.
- The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup, shutdown, or a reduced load period.
- An operator may submit an application to allow more than two hours for each startup or each shutdown or more than one hour for each reduced load period provided the operator meets all of the conditions specified in the rule.

The facility is proposing to incorporate startup and shutdown provisions into the operating requirements for the proposed turbine. The facility has proposed that the duration of each startup or shutdown event will last no more than two hours. The SCR system and oxidation catalyst will be in operation during startup and shutdown in order to minimize emissions insofar as technologically feasible during startups and shutdowns. Therefore, the proposed turbine will be operating in compliance with the startup and shutdown requirements of this rule. The following conditions will be listed on the permit to ensure compliance with the requirements of this section:

- During startup of the unit, emissions shall not exceed any of the following limits: 1.6 lb-NO<sub>x</sub> (as NO<sub>2</sub>)/startup; 0.053 lb-SO<sub>x</sub> (as SO<sub>2</sub>)/startup; 0.423 lb-PM<sub>10</sub>/startup; 9.3 lb-CO/startup; or 0.5 lb-VOC (as methane)/startup. [District Rule 2201]
- During shutdown of the unit, emissions shall not exceed any of the following limits: 0.4 lb-NO<sub>x</sub> (as NO<sub>2</sub>)/shutdown; 0.024 lb-SO<sub>x</sub> (as SO<sub>2</sub>)/shutdown; 0.192 lb-PM<sub>10</sub>/startup; 34.7 lb-CO/shutdown; or 0.2 lb-VOC (as methane)/shutdown. [District Rule 2201]
- Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]
- The duration of each startup or shutdown shall not exceed 22 minutes and 10 minutes respectively. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]
- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

## Section 6.2 – Monitoring and Record Keeping

Section 6.2.1 requires the owner or operator to either install, operate, and maintain continuous emissions monitoring equipment for NO<sub>x</sub> and oxygen, as identified in Rule 1080 (Stack Monitoring), or install and maintain APCO-approved alternate monitoring. The applicant has proposed to determine a relation between the ammonia injection rate and the NO<sub>x</sub> emissions rate. The applicant will then monitor the ammonia injection rate to the SCR system to determine NO<sub>x</sub> compliance. To factor in degradation of the SCR catalyst, the applicant will be required to periodically monitor the NO<sub>x</sub> and O<sub>2</sub> emissions rates using a portable analyzer. The following conditions will be listed on the permit to ensure compliance with the requirements of this section:

- Ammonia shall be injected whenever the selective catalytic reduction system catalyst temperature exceeds the minimum ammonia injection temperature recommended by the manufacturer. [District Rule 2201 and 4703]
- During initial performance testing, the ammonia injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit (with or without the duct burner operating). The minimum ammonia injection rate(s) demonstrated during the initial performance test to result in compliance with the NO<sub>x</sub> emission limits shall be imposed as a condition in the Permit to Operate. [District Rules 2201 and 4703]

- If the ammonia injection rate is less than the minimum ammonia injection rate demonstrated during the initial compliance test, the permittee shall return the ammonia injection rate above the minimum ammonia injection rate established during compliance testing as soon as possible, but no longer than 8 hours after detection. If the ammonia injection rate is not returned above the minimum ammonia injection rate established during compliance testing within 8 hours, the permittee shall notify the District within the following 1 hour and conduct a source test within 60 days of the first exceedance to demonstrate compliance with the applicable emission limits at the reduced ammonia injection rate. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4703]
- The permittee shall monitor and record the stack concentration of NO<sub>x</sub> (as NO<sub>2</sub>), CO, and O<sub>2</sub> weekly. If compliance with the NO<sub>x</sub> and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation (i.e. the unit need not be started solely to perform monitoring). Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703]
- If the NO<sub>x</sub> and/or CO concentrations, as measured by the permittee with a portable analyzer, exceed the permitted emission limits, the permittee shall notify the District and return the NO<sub>x</sub> and CO concentrations to the permitted emission limits as soon as possible but no longer than eight (8) hours after detection. If the permittee's portable analyzer readings continue to exceed the permitted emissions limits after eight (8) hours, the permittee shall notify the District within the following one (1) hour, and conduct a certified source test within 60 days to demonstrate compliance with the permitted emissions limits. In lieu of conducting a source test, the permittee may stipulate that a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4703]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas NO<sub>x</sub> control devices. The proposed turbine will be equipped with an SCR system that is designed to control NO<sub>x</sub> emissions. Therefore, the requirements of this section are not applicable.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas NO<sub>x</sub> emissions. The proposed turbine was not in operation prior to August 18, 1994 and the requirements of this section are not applicable.



Section 6.2.4 requires the facility to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. The facility will be required to maintain all records for at least five years and make them available to the APCO upon request. Therefore, the proposed turbine will be operating in compliance with the five year recordkeeping requirements of this rule. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, and 4703]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure NO<sub>x</sub> output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for NO<sub>x</sub> available or when the continuous emissions monitoring system is not operating properly. The facility will not install and operate a NO<sub>x</sub> CEMS. Therefore, the requirements of this section are not applicable to this project.

Section 6.2.6 requires the facility to maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. The facility will be required to maintain records of each item listed above. Therefore, the proposed turbine will be operating in compliance with the recordkeeping requirements of this rule. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local start-up time and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. [District Rule 4703]

Section 6.2.7 establishes recordkeeping requirements for units that are exempt pursuant to the requirements of Section 4.2. The proposed turbine is subject to the requirements of this rule. Therefore, the requirements of this section are not applicable.

Section 6.2.8 requires owners or operators performing startups or shutdowns to keep records of the duration of each startup and shutdown. As discussed in the Section 6.2.6 discussion above for this rule, the facility will be required, by permit condition, to maintain records of the date, time and duration of each startup and shutdown. Therefore, the proposed turbine will be operating in compliance with the recordkeeping requirements of this rule.

## Sections 6.3 and 6.4 – Compliance Testing

Section 6.3.1 states that the owner or operator of any stationary gas turbine system subject to the provisions of Section 5.0 of this rule shall provide source test information annually regarding the exhaust gas NO<sub>x</sub> and CO concentrations. The turbine operated by the facility is subject to the provisions of Section 5.0 of this rule. Therefore, the turbine is required to test annually to demonstrate compliance with the exhaust gas NO<sub>x</sub> and CO concentrations. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- Performance testing to measure the NO<sub>x</sub> (ppmvd), CO (ppmvd), VOC (ppmvd), and NH<sub>3</sub> (ppmvd) emissions shall be conducted within 60 days of startup and at least once every twelve months thereafter. [District Rules 2201 and 4703 and 40 CFR 60.4340 and 60.4400]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, the proposed turbine will be allowed to operate greater than 877 hours per year. Therefore, the requirements of this section are not applicable.

Section 6.3.3 specifies source testing requirements for units that are equipped with intermittently operated auxiliary burners. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- Any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [District Rule 4703]

Section 6.4 states that the facility must demonstrate compliance annually with the NO<sub>x</sub> and CO emission limits using the following test methods, unless otherwise approved by the APCO and EPA:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.
- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.
- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.
- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

The following conditions will be listed on the permit to ensure compliance with the requirements of this section:

- NO<sub>x</sub> emissions (referenced as NO<sub>2</sub>) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, and 4703 and 40 CFR 60.4400]
- CO emissions shall be determined using EPA Method 10 or EPA Method 10B. [District Rule 1081, 2201, and 4703]

- The oxygen content of the exhaust gas shall be determined by using EPA Method 3, EPA Method 3A, or EPA Method 20. [District Rules 1081, 2201, and 4703]
- HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [District Rule 4703]

### Conclusion

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this rule. Therefore, compliance with the requirements of 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<sub>2</sub>, on a dry basis averaged over 15 consecutive minutes.

Using the ideal gas equation and the emission factors presented in Section VII, the sulfur compound emissions are calculated as follows:

$$\text{Volume SO}_2 = \frac{n RT}{P}$$

With:

N = moles SO<sub>2</sub>

T (Standard Temperature) = 60°F = 520°R

P (Standard Pressure) = 14.7 psi

R (Universal Gas Constant) =  $\frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot ^\circ\text{R}}$

0.75 gr-S/100 scf:

$$\frac{0.00214 \text{ lb} - \text{SO}_x}{\text{MMBtu}} \times \frac{\text{MMBtu}}{8,578 \text{ dscf}} \times \frac{1 \text{ lb} \cdot \text{mol}}{64 \text{ lb}} \times \frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot ^\circ\text{R}} \times \frac{520^\circ\text{R}}{14.7 \text{ psi}} \times \frac{1,000,000 \cdot \text{parts}}{\text{million}} = 1.48 \frac{\text{parts}}{\text{million}}$$

$$\text{Sulfur Concentration} = 1.48 \frac{\text{parts}}{\text{million}} < 2,000 \text{ ppmv (or 0.2\%)}$$

Therefore, compliance with District Rule 4801 requirements is expected.

### **California Health & Safety Code 42301.6 (School Notice)**

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

## **California Environmental Quality Act (CEQA)**

The California Environmental Quality Act (CEQA) requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The San Joaquin Valley Unified Air Pollution Control District (District) adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities.
- Identify the ways that environmental damage can be avoided or significantly reduced.
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible.
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

The District determined that no other agency has broader discretionary approval power over the project and that the District is the first agency to act on the project, therefore establishing the District as the Lead Agency for the project (CEQA Guidelines §15051(b)). An Initial Study was prepared, which identified impacts on air quality, and cultural resources as the project's potential significant environmental effects.

The District's engineering evaluation of the project (this document) and the Initial Study demonstrates that compliance with District rules and permit conditions and Project design elements would reduce and mitigate the project's potential environmental impacts to less than significant. Consistent with CEQA Guidelines §15070, a Proposed Mitigated Negative Declaration was prepared and released for public review from October 9, 2015 to November 9, 2015.

## **IX. Recommendation**

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue Authority to Construct permit S-1246-416-0 subject to the permit conditions on the attached draft Authority to Construct permits in Attachment E.

**X. Billing Information**

<b>Annual Permit Fees</b>			
<b>Permit Number</b>	<b>Fee Schedule</b>	<b>Fee Description</b>	<b>Annual Fee</b>
S-1246-416-0	3020-8A-D	5.67 MW	\$3,062

Attachments

- A: BACT Guideline 3.4.3 and Top Down BACT Analysis
- B: Compliance Certification
- C: Certificate of Conformity
- D: Health Risk Assessment and Ambient Air Quality Analysis
- E: Draft Authority to Construct Permit

## **Attachment A**

### **BACT Guideline 3.4.3 and Top Down BACT Analysis**

San Joaquin Valley  
Unified Air Pollution Control District

**Best Available Control Technology (BACT) Guideline 3.4.3\***

Last Update 1/18/2005

**Gas Turbine with Heat Recovery (= > 3 MW and = < 10 MW)**

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	6.0 ppmv @ 15% O <sub>2</sub> , based on a three-hour average (catalytic oxidation or equal)		
NOx	2.5 ppmv @ 15% O <sub>2</sub> , based on a three-hour average (selective catalytic reduction or equal)		
PM10	air inlet cooler, lube oil vent coalescer, and natural gas fuel		
SOx	PUC-regulated natural gas, LPG, or non-PUC-regulated natural gas with < 0.75 grains-S/100 dscf, or equal		
VOC	2.0 ppmv @ 15% O <sub>2</sub> , based on a three-hour average (catalytic oxidation or equal)		

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**

## 1. NO<sub>x</sub> Top-Down BACT Analysis for Permit Unit S-1246-416-0

### Step 1 – Identify all control technologies

SJVAPCD BACT Clearinghouse, Guideline 3.4.3, Gas Turbine with Heat Recovery ( $\geq$  3 MW and  $\leq$  10 MW), 3rd quarter 2015, identifies BACT for NO<sub>x</sub> emissions as follows:

- 1) 2.5 ppmv @ 15% O<sub>2</sub>, based on a three-hour average (selective catalytic reduction or equal) (Achieved in Practice)

### Step 2 - Eliminate Technologically Infeasible Options

None of the above listed technologies are technologically infeasible.

### Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	2.5 ppmv @ 15% O <sub>2</sub> , based on a three-hour average (selective catalytic reduction or equal)	Y

There are no remaining control technologies for NO<sub>x</sub>.

### Step 4 - Cost Effectiveness Analysis

This option listed above has been identified as achieved in practice for NO<sub>x</sub> emissions. Therefore, a cost analysis is not necessary.

### Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the gas turbine must be satisfied with the following:

NO<sub>x</sub>: 2.5 ppmv @ 15% O<sub>2</sub>, based on a three-hour average (selective catalytic reduction or equal) (Achieved in Practice)

The applicant has proposed to utilize an SCR system with the gas turbine system to reduce NO<sub>x</sub> emissions to 2.5 ppmvd @ 15% O<sub>2</sub>, based on a three-hour average. Therefore, the BACT requirements are satisfied.



## 2. SO<sub>x</sub> Top-Down BACT Analysis for Permit Unit S-1246-416-0

### Step 1 – Identify all control technologies

SJVAPCD BACT Clearinghouse, Guideline 3.4.3, Gas Turbine with Heat Recovery ( $\geq$  3 MW and  $\leq$  10 MW), 3<sup>rd</sup> quarter 2015, identifies BACT for SO<sub>x</sub> emissions as follows:

- 1) PUC-regulated natural gas, LPG, or on-PUC-regulated natural gas with  $< 0.75$  grains-S/100 scf, or equal (Achieved in Practice)

### Step 2 - Eliminate Technologically Infeasible Options

None of the above listed technologies are technologically infeasible.

### Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	PUC-regulated natural gas, LPG, or non-PUC-regulated natural gas with $< 0.75$ grains-S/100 scf, or equal	Y

There are no remaining control technologies for SO<sub>x</sub>.

### Step 4 - Cost Effectiveness Analysis

This option listed above has been identified as achieved in practice for SO<sub>x</sub> emissions. Therefore, a cost analysis is not necessary.

### Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the gas turbine must be satisfied with the following:

SO<sub>x</sub>: PUC-regulated natural gas, LPG, or on-PUC-regulated natural gas with  $< 0.75$  grains-S/100 scf, or equal (Achieved in Practice)

The applicant has proposed to utilize PUC-quality natural gas with a sulfur content of less than or equal to 0.75 grains/100 scf for the turbine and duct burner. Therefore, the BACT requirements are satisfied.

### 3. PM<sub>10</sub> Top-Down BACT Analysis for Permit Unit S-1246-416-0

#### Step 1 – Identify all control technologies

SJVAPCD BACT Clearinghouse, Guideline 3.4.3, Gas Turbine with Heat Recovery ( $\geq$  3 MW and  $\leq$  10 MW), 3<sup>rd</sup> quarter 2015, identifies BACT for PM<sub>10</sub> emissions as follows:

- 1) Air inlet cooler, lube oil vent coalescer, and natural gas fuel (Achieved in Practice)

#### Step 2 - Eliminate Technologically Infeasible Options

None of the above listed technologies are technologically infeasible.

#### Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	Air inlet cooler, lube oil vent coalescer, and natural gas fuel	Y

There are no remaining control technologies for PM<sub>10</sub>.

#### Step 4 - Cost Effectiveness Analysis

This option listed above has been identified as achieved in practice for PM<sub>10</sub> emissions. Therefore, a cost analysis is not necessary.

#### Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the gas turbine must be satisfied with the following:

PM<sub>10</sub>: Air inlet cooler, lube oil vent coalescer, and natural gas fuel (Achieved in Practice)

The applicant has proposed to utilize an air inlet cooler or lube oil vent coalescer and natural gas fuel. Therefore, the BACT requirements are satisfied.

#### 4. VOC Top-Down BACT Analysis for Permit Unit S-1246-416-0

##### Step 1 – Identify all control technologies

SJVAPCD BACT Clearinghouse, Guideline 3.4.3, Gas Turbine with Heat Recovery ( $\geq$  3 MW and  $\leq$  10 MW), 3<sup>rd</sup> quarter 2015, identifies BACT for VOC emissions as follows:

- 1) 2.0 ppmv @ 15% O<sub>2</sub>, based on a three-hour average (catalytic oxidation or equal) (Achieved in Practice)

##### Step 2 - Eliminate Technologically Infeasible Options

None of the above listed technologies are technologically infeasible.

##### Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	2.0 ppmv @ 15% O <sub>2</sub> , based on a three-hour average (catalytic oxidation or equal)	Y

There are no remaining control technologies for VOC.

##### Step 4 - Cost Effectiveness Analysis

This option listed above has been identified as achieved in practice for VOC emissions. Therefore, a cost analysis is not necessary.

##### Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the gas turbine must be satisfied with the following:

VOC: 2.0 ppmv @ 15% O<sub>2</sub>, based on a three-hour average (catalytic oxidation or equal) (Achieved in Practice)

The applicant has proposed to utilize a catalytic oxidation system to reduce VOC emissions to 2.0 ppmvd @ 15% O<sub>2</sub>, based on a three-hour average. Therefore, the BACT requirements are satisfied.

**Attachment B**  
**Compliance Certification**



5201 Truxtun Ave.  
Bakersfield, California 93309

Phone: (661) 616-3900

RECEIVED  
APR 23 2015  
SJVAPCD  
Southern Region

April 06, 2015

Mr. Leonard Scandura  
San Joaquin Valley Unified APCD  
34946 Flyover Court  
Bakersfield, CA 93308

**RE: ATC Applications S- S-1246 Statewide Compliance Certification per District Rule 2201 Section 4.15.2**

Dear Mr. Scandura:

Pursuant to the requirement of San Joaquin Valley APCD Rule 2201 section 4.15.2, Linn Operating, Inc. (Linn) submits this Compliance Certification regarding other owned, operated, or controlled major stationary sources in California. As of the date of this letter, Linn asserts that all major stationary sources owned or operated by Linn (or by any entity controlling, controlled by, or under common control with Linn) in California, which are subject to emission limitations, are in compliance or on a schedule for compliance with all applicable emission limitations and standards.

If you have any questions or require additional information please contact Mr. Shamim Reza at (661) 616-3889.

Sincerely,

Tim Crawford  
Vice President California Region

**Attachment C**  
**Certificate of Conformity**

RECEIVED

APR 23 2015

SJVAPCD  
Southern Region

# San Joaquin Valley Unified Air Pollution Control District

## TITLE V MODIFICATION - COMPLIANCE CERTIFICATION FORM

### I. TYPE OF PERMIT ACTION (Check appropriate box)

- SIGNIFICANT PERMIT MODIFICATION                       ADMINISTRATIVE  
 MINOR PERMIT MODIFICATION                                       AMENDMENT

COMPANY NAME: <b>Linn Operating, Inc.</b>	FACILITY ID: S-1246, S-2265 & S-3585
1. Type of Organization: <input checked="" type="checkbox"/> Corporation <input type="checkbox"/> Sole Ownership <input type="checkbox"/> Government <input type="checkbox"/> Partnership <input type="checkbox"/> Utility	
2. Owner's Name: <b>Linn Operating, Inc.</b>	
3. Agent to the Owner: <b>Tim Crawford</b>	

### II. COMPLIANCE CERTIFICATION (Read each statement carefully and initial all circles for confirmation):

- RSB** Based on information and belief formed after reasonable inquiry, the equipment identified in this application will continue to comply with the applicable federal requirement(s).
- RSB** Based on information and belief formed after reasonable inquiry, the equipment identified in this application will comply with applicable federal requirement(s) that will become effective during the permit term, on a timely basis.
- RSB** Corrected information will be provided to the District when I become aware that incorrect or incomplete information has been submitted.
- RSB** Based on information and belief formed after reasonable inquiry, information and statements in the submitted application package, including all accompanying reports, and required certifications are true accurate and complete.

I declare, under penalty of perjury under the laws of the state of California, that the forgoing is correct and true:

*Robert E. Boston*

Signature of Responsible Official

3-24-15

Date

**Robert Boston**

Name of Responsible Official (please print)

**Manager of EHS**

Title of Responsible Official (please print)

## **Attachment D**

### **Health Risk Assessment and Ambient Air Quality Analysis**



# San Joaquin Valley Air Pollution Control District Revised Risk Management Review

To: Dustin Brown – Permit Services  
 From: Leland Villalvazo – Technical Services  
 Date: September 22, 2015  
 Facility Name: Linn Operating, Inc.  
 Location: Derby Acers  
 Application #(s): S-1246-416-0  
 Project #: S-1151997

---

## A. RMR SUMMARY

RMR Summary				
Categories	Cogen (Unit 416-0)		Project Totals	Facility Totals
Prioritization Score	NA <sup>1</sup>		NA <sup>1</sup>	>1.0
Acute Hazard Index	5.90E-04		5.90E-04	0.7
Chronic Hazard Index	2.79E-05		2.79E-05	0.03
Maximum Individual Cancer Risk (10 <sup>-6</sup> )	0.0024		0.0024	17.9
T-BACT Required?	No			
Special Permit Conditions?	No			

<sup>1</sup>Prioritization for this unit was not conducted since the facility total prioritization score is greater than 1.0.

### Proposed Permit Conditions

To ensure that human health risks will not exceed District allowable levels; the following permit conditions must be included for:

Unit # 416-0

No special conditions are required.

## B. RMR REPORT

### I. Project Description

Technical Services received a request on May 28, 2015, to perform an Ambient Air Quality Analysis and a Risk Management Review to install one 67.9 MMBTU/HR natural gas-fired solar model Taurus 60 (T-60) turbine and one 57 MMBTU/HR natural gas-fired Rentech duct burner with Rentech selective catalytic reduction (SCR) and CO catalyst and heat recovery steam generator (HRSG).

## II. Analysis

Technical Services performed a prioritization using the District's HEARTs database. Since the total facility prioritization score was greater than one, a refined health risk assessment was required. Emissions calculated using Ventura County emission factors for internal combustion of natural gas were input into the HEARTs database. The AERMOD model was used with the parameters outlined below and meteorological data for 2004-2008 from Fellows to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the Hot Spots Analysis and Reporting Program (HARP2) risk assessment module to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Unit 416-0			
Source Type	Point	Location Type	Rural
Stack Height (m)	9.144	Closest Receptor (m)	Various
Stack Diameter. (m)	1.2192	Type of Receptor	Residential
Stack Exit Velocity (m/s)	19.394	Max Hours per Year	8760
Stack Exit Temp. (°K)	375.928	Fuel Type	NG
Burner Rating (MMBtu/hr)	124.9		

Technical Services performed modeling for criteria pollutants CO, NO<sub>x</sub>, SO<sub>x</sub> and PM<sub>10</sub>; as well as a RMR. The emission rates used for criteria pollutant modeling were 265.8 lb/day CO, 30.0 lb/day NO<sub>x</sub>, 8.3 lb/day SO<sub>x</sub>, and 49.9 lb/day PM<sub>10</sub>.

The results from the Criteria Pollutant Modeling are as follows:

### Criteria Pollutant Modeling Results\*

Diesel ICE	1 Hour	3 Hours	8 Hours.	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO <sub>x</sub>	Pass <sup>1</sup>	X	X	X	Pass
SO <sub>x</sub>	Pass	Pass	X	Pass	Pass
PM <sub>10</sub>	X	X	X	Pass <sup>2</sup>	Pass <sup>2</sup>
PM <sub>2.5</sub>	X	X	X	Pass <sup>2</sup>	Pass <sup>2</sup>

\*Results were taken from the attached PSD spreadsheet.

<sup>1</sup>The project was compared to the 1-hour NO<sub>2</sub> National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.

<sup>2</sup>The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

## III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk factor associated with the project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

#### **IV. Attachments**

- A. RMR request from the project engineer
- B. Additional information from the applicant/project engineer
- C. Toxic emissions summary
- D. Prioritization score
- E. Facility Summary

## **Attachment E**

### **Draft Authority to Construct Permit**

San Joaquin Valley  
Air Pollution Control District

**AUTHORITY TO CONSTRUCT**

**ISSUANCE DATE:** DRAFT

**PERMIT NO:** S-1246-416-0

**LEGAL OWNER OR OPERATOR:** LINN OPERATING, INC  
**MAILING ADDRESS:** 5201 TRUXTUN AVE, SUITE 100  
BAKERSFIELD, CA 93309

**LOCATION:** HEAVY OIL WESTERN STATIONARY SOURCE  
KERN COUNTY, CA

**SECTION:** 2 **TOWNSHIP:** 31S **RANGE:** 22E

**EQUIPMENT DESCRIPTION:**

5.67 MW (ISO RATED) COMBINED HEAT AND POWER COGENERATION SYSTEM CONSISTING OF ONE 67.9 MMBTU/HR NATURAL GAS-FIRED SOLAR MODEL TAURUS 60 (T-60) TURBINE AND ONE 57 MMBTU/HR NATURAL GAS-FIRED RENTECH DUCT BURNER WITH RENTECH SELECTIVE CATALYTIC REDUCTION (SCR) AND CO CATALYST AND HEAT RECOVERY STEAM GENERATOR (HRSG)

**CONDITIONS**

1. {1830} This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201] Federally Enforceable Through Title V Permit
2. {1831} Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Federally Enforceable Through Title V Permit
3. Prior to operating equipment under this Authority to Construct, permittee shall surrender NOx emission reduction credits for the following quantity of emissions: 1st quarter - 3,724 lb, 2nd quarter - 3,724 lb, 3rd quarter - 3,725 lb, and fourth quarter - 3,725 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201] Federally Enforceable Through Title V Permit
4. Prior to operating equipment under this Authority to Construct, permittee shall surrender SOx emission reduction credits for the following quantity of emissions: 1st quarter - 878 lb, 2nd quarter - 878 lb, 3rd quarter - 878 lb, and fourth quarter - 878 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201] Federally Enforceable Through Title V Permit

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YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. 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. 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.

Seyed Sadredin, Executive Director, APCO

Arnaud Marjolle, Director of Permit Services

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5. Prior to operating equipment under this Authority to Construct, permittee shall surrender PM10 emission reduction credits for the following quantity of emissions: 1st quarter - 6,974 lb, 2nd quarter - 6,974 lb, 3rd quarter - 6,974 lb, and fourth quarter - 6,974 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. SOx ERCs may be used to offset PM10 increases at an interpollutant ratio of 1.000 lb-SOx: 1.0 lb-PM10. [District Rule 2201] Federally Enforceable Through Title V Permit
6. Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantity of emissions: 1st quarter - 1,035 lb, 2nd quarter - 1,035 lb, 3rd quarter - 1,035 lb, and fourth quarter - 1,035 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201] Federally Enforceable Through Title V Permit
7. ERC Certificate Numbers S-4514-2, S-4515-2, S-4516-2, S-4530-2, N-1302-2, N-1332-2, S-4508-5, N-1307-5, N-1309-5, C-1353-5, S-4533-5, S-4539-5, N-1206-4, N-1312-4, S-4510-4, S-4583-4, N-1202-1, N-1295-1, N-1296-1, N-1297-1, S-4500-1, S-4502-1, S-4504-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201] Federally Enforceable Through Title V Permit
8. 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] Federally Enforceable Through Title V Permit
9. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
10. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit
11. 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] Federally Enforceable Through Title V Permit
12. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
13. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine engine and duct burner. Exhaust ducting may be equipped (if required) with a fresh air inlet blower, to lower the exhaust temperature prior to the inlet of the SCR catalyst. [District Rule 2201] Federally Enforceable Through Title V Permit
14. The turbine/electrical generator shall be equipped with an air inlet filter and a lube oil vent coalescer (or equivalent). [District Rule 2201] Federally Enforceable Through Title V Permit
15. The turbine and duct burner shall be fired on PUC-quality natural gas and/or ethane-rich natural gas and the natural gas shall have a total sulfur content of less than or equal to 0.75 gr/100 scf. [District Rules 2201 and 4801 and 40 CFR 60.4330] Federally Enforceable Through Title V Permit
16. During startup of the unit, emissions shall not exceed any of the following limits: 1.6 lb-NOx (as NO2)/startup; 0.053 lb-SOx (as SO2)/startup; 0.423 lb-PM10/startup; 79.3 lb-CO/startup; or 0.5 lb-VOC (as methane)/startup. [District Rule 2201] Federally Enforceable Through Title V Permit
17. During shutdown of the unit, emissions shall not exceed any of the following limits: 0.4 lb-NOx (as NO2/shutdown); 0.024 lb-SOx (as SO2)/shutdown; 0.192 lb-PM10/shutdown; 34.7 lb-CO/shutdown; or 0.2 lb-VOC (as methane)/shutdown. [District Rule 2201] Federally Enforceable Through Title V Permit
18. NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.13 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 1.65 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.31 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320] Federally Enforceable Through Title V Permit
19. PM10 emissions from this unit (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 2.12 lb/hr or 0.017 lb/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit

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20. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit
21. The duration of each startup or shutdown shall not exceed 22 minutes and 10 minutes respectively. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit
22. The total duration of startup time shall not exceed either of the following: 44 minutes per day or 132 minutes per year. [District Rule 2201] Federally Enforceable Through Title V Permit
23. The total duration of shutdown time shall not exceed either of the following: 20 minutes per day or 60 minutes per year. [District Rule 2201] Federally Enforceable Through Title V Permit
24. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703] Federally Enforceable Through Title V Permit
25. The ammonia slip (NH<sub>3</sub>) emissions shall not exceed either of the following limits: 0.56 lb/hr or 10.0 ppmvd @15% O<sub>2</sub> (based on a 24 hour rolling average). [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit
26. Annual emissions from the turbine and duct burner system (as measured after the CO Catalyst and SCR Catalyst), including startup and shutdown emissions, shall not exceed any of the following limits: NO<sub>x</sub>: 9,932 lb/year (as NO<sub>2</sub>); SO<sub>x</sub>: 2,341 lb/year (as SO<sub>2</sub>); PM<sub>10</sub>: 18,597 lb/year; CO: 15,121 lb/year; VOC: 2,760 lb/year (as methane); or NH<sub>3</sub>: 4,922 lb/year. All annual emissions limits are based on 12 consecutive month rolling emissions totals. [District Rule 2201] Federally Enforceable Through Title V Permit
27. Each calendar month in a twelve consecutive month rolling emissions total will commence at the beginning of the first day of the month. The twelve consecutive month rolling emissions totals to determine compliance with annual emission limits will be compiled from the twelve most recent calendar months. [District Rule 2201] Federally Enforceable Through Title V Permit
28. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100] Federally Enforceable Through Title V Permit
29. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100] Federally Enforceable Through Title V Permit
30. Performance testing to measure the NO<sub>x</sub> (ppmvd), CO (ppmvd), VOC (ppmvd), and NH<sub>3</sub> (ppmvd) emissions shall be conducted within 60 days of startup and at least once every twelve months thereafter. [District Rules 2201, 4102, and 4703 and 40 CFR 60.4340 and 60.4400] Federally Enforceable Through Title V Permit
31. Performance testing to measure the PM<sub>10</sub> emissions (lb/hr) shall be conducted within 60 days of startup. [District Rule 2201] Federally Enforceable Through Title V Permit
32. Any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [District Rule 4703] Federally Enforceable Through Title V Permit
33. The owner or operator shall be required to conform to the sampling facilities and testing procedures described in District Rule 1081 (as amended 12/16/93), Sections 3.0 and 6.1. [District Rule 1081] Federally Enforceable Through Title V Permit
34. The District must be notified 30 days prior to any performance testing and a test plan shall be submitted for District Approval 15 days prior to such testing. [District Rule 1081] Federally Enforceable Through Title V Permit
35. Performance testing shall be witnessed or authorized by District personnel. Test results must be submitted to the District within 60 days of performance testing. [District Rule 1081] Federally Enforceable Through Title V Permit

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36. NO<sub>x</sub> emissions (referenced as NO<sub>2</sub>) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, and 4703 and 40 CFR 60.4400] Federally Enforceable Through Title V Permit
37. VOC emissions (referenced as methane) shall be determined using EPA Method 18 or EPA Method 25. [District Rules 1081 and 2201] Federally Enforceable Through Title V Permit
38. CO emissions shall be determined using EPA Method 10 or EPA Method 10B. [District Rule 1081, 2201, and 4703] Federally Enforceable Through Title V Permit
39. PM<sub>10</sub> emissions shall be determined using EPA Methods 201 and 202, or EPA Methods 201A and 202, or CARB Method 501 in conjunction with CARB Method 5. [District Rules 1081 and 2201] Federally Enforceable Through Title V Permit
40. Ammonia (NH<sub>3</sub>) emissions shall be determined using BAAQMD Method ST-1B. [District Rules 1081, 2201, and 4102] Federally Enforceable Through Title V Permit
41. The oxygen content of the exhaust gas shall be determined by using EPA Method 3, EPA Method 3A, or EPA Method 20. [District Rules 1081, 2201, and 4703] Federally Enforceable Through Title V Permit
42. HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [District Rule 4703] Federally Enforceable Through Title V Permit
43. Ammonia shall be injected whenever the selective catalytic reduction system catalyst temperature exceeds the minimum ammonia injection temperature recommended by the manufacturer. [District Rule 2201 and 4703] Federally Enforceable Through Title V Permit
44. During initial performance testing, the ammonia injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit (with or without the duct burner operating). The minimum ammonia injection rate(s) demonstrated during the initial performance test to result in compliance with the NO<sub>x</sub> emission limits shall be imposed as a condition in the Permit to Operate. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit
45. If the ammonia injection rate is less than the minimum ammonia injection rate demonstrated during the initial compliance test, the permittee shall return the ammonia injection rate above the minimum ammonia injection rate established during compliance testing as soon as possible, but no longer than 8 hours after detection. If the ammonia injection rate is not returned above the minimum ammonia injection rate established during compliance testing within 8 hours, the permittee shall notify the District within the following 1 hour and conduct a source test within 60 days of the first exceedance to demonstrate compliance with the applicable emission limits at the reduced ammonia injection rate. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit
46. The permittee shall monitor and record the stack concentration of NO<sub>x</sub> (as NO<sub>2</sub>), CO, and O<sub>2</sub> weekly. If compliance with the NO<sub>x</sub> and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation (i.e. the unit need not be started solely to perform monitoring). Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703 and 40 CFR 60.4415] Federally Enforceable Through Title V Permit

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47. If the NO<sub>x</sub> and/or CO concentrations, as measured by the permittee with a portable analyzer, exceed the permitted emission limits, the permittee shall notify the District and return the NO<sub>x</sub> and CO concentrations to the permitted emission limits as soon as possible but no longer than eight (8) hours after detection. If the permittee's portable analyzer readings continue to exceed the permitted emissions limits after eight (8) hours, the permittee shall notify the District within the following one (1) hour, and conduct a certified source test within 60 days to demonstrate compliance with the permitted emissions limits. In lieu of conducting a source test, the permittee may stipulate that a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4703 and 40 CFR 60.4415] Federally Enforceable Through Title V Permit
48. The operator shall demonstrate compliance with the fuel sulfur content limit of 0.75 grains of sulfur compounds (as S) per 100 dry scf of natural gas at least once per week. Once compliance is demonstrated for eight consecutive weeks, the frequency for demonstrating compliance with the fuel sulfur content may be reduced to once every calendar quarter. If a quarterly determination shows a violation of the sulfur content limit, then weekly demonstrations shall resume and continue until eight consecutive demonstrations show compliance. Once compliance is shown on eight consecutive weekly determinations, then determinations may return to quarterly. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)] Federally Enforceable Through Title V Permit
49. The sulfur fuel content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. If compliance is being demonstrated through fuel sulfur content testing, the testing shall occur at a location after all fuel sources are combined prior to combustion, or by performing mass balance calculations based on testing the sulfur content and volume of each fuel source. [40 CFR 60.4415(a)(1)(i)] Federally Enforceable Through Title V Permit
50. Excess SO<sub>x</sub> emissions is each unit operating hour including in the period beginning on the date and hour of any sample for which the fuel sulfur content exceeds the applicable limits listed in this permit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit. Monitoring downtime for SO<sub>x</sub> begins when a sample is not taken by its due date. A period of monitor downtime for SO<sub>x</sub> also begins on the date and hour of a required sample, if invalid results are obtained. A period of SO<sub>x</sub> monitoring downtime ends on the date and hour of the next valid sample. [40 CFR 60.4385(a) and (c)] Federally Enforceable Through Title V Permit
51. Compliance with ammonia emission limit shall be demonstrated utilizing one of the following procedures: 1) The permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. 2) The permittee may utilize a District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O<sub>2</sub>. The permittee shall submit a detailed calculation protocol or monitoring plan for District Approval at least 60 days prior to the commencement of operation. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit
52. The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local start-up time and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. [District Rule 4703] Federally Enforceable Through Title V Permit
53. The permittee shall provide notification and recordkeeping as required under 40 CFR, Part 60, Subpart A, 60.7. [40 CFR 60.7] Federally Enforceable Through Title V Permit
54. The permittee shall maintain a record of the cumulative 12 month rolling NO<sub>x</sub>, CO, VOC, SO<sub>x</sub>, PM<sub>10</sub>, and NH<sub>3</sub> emissions total, in lb/year, from this unit. These records shall be updated at the end of each month. [District Rule 2201] Federally Enforceable Through Title V Permit
55. The permittee shall maintain a daily record of the ammonia injection rate and SCR catalyst inlet temperature. [District Rule 2201] Federally Enforceable Through Title V Permit

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56. The owner or operator shall submit a written report of excess emissions and monitoring downtime to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Applicable time and date of each period during monitor downtime; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375 and 60.4395] Federally Enforceable Through Title V Permit
57. Permittee shall submit notification of the initial startup of the duct burner, as provided by 40 CFR Part 60 Section 60.7 to the EPA administrator. The notification shall include the design heat input capacity of the duct burner, identify the fuels to be combusted in the duct burner, and a copy of the performance test data from the initial performance tests for NOx emissions from the turbine and duct burner. [40 CFR 60.7] Federally Enforceable Through Title V Permit
58. All records shall be retained for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070, 2201, and 4703] Federally Enforceable Through Title V Permit

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