

PROPOSED
ENGINEERING EVALUATION
Air Liquide Large Industries, U.S. LP; Facility B7419
APPLICATION NO. 13678

March 13, 2007

Table of Contents

1. BACKGROUND 3

2. EMISSIONS 5

3. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)..... 13

4. CUMULATIVE INCREASE AND OFFSETS..... 17

5. STATEMENT OF COMPLIANCE 18

6. RECOMMENDATIONS 29

7. PERMIT CONDITIONS 29

APPENDIX A..... 41

APPENDIX B..... 51

1. BACKGROUND

Air Liquide has submitted an application to build a hydrogen plant at the ConocoPhillips refinery in Rodeo. This is part of ConocoPhillips "Clean Fuel Expansion Project (CFEP)." The purpose of the project is to process heavy gas oil that Conoco produces at the coker crude unit, coker, and pre-fractionator into gasoline and diesel fuel.

Conoco needs more hydrogen than it can currently produce to process the heavy gas oil. Air Liquide will build a new hydrogen plant on site and will retain ownership of the plant and operate it. However, Conoco will use all of the facility's output. BAAQMD Regulation 2-1-213 defines facility as:

"Any property, building, structure or installation (or any aggregation of facilities) located on one or more contiguous or adjacent properties and under common ownership or control of the same person..."

The hydrogen plant will be on Conoco property, so it meets the conditions of "contiguous or adjacent." In addition, the hydrogen plant will take its feed from the refinery. Conoco will direct the hydrogen plant to produce the amount of hydrogen that it needs at any time, so the hydrogen plant is considered to be under Conoco's control. Therefore, the hydrogen plant will be considered to be part of the refinery.

Since it is part of the refinery, the two projects (CFEP and hydrogen plant) will be considered as one project for the purposes of NSR, PSD, Major Facility Review (Title V), offsets, NSPS, NESHAPS, and any other applicable requirements.

The Title V regulations in 40 CFR 70 allow agencies to issue more than one Title V permit to a facility. Because the hydrogen plant will be owned and operated by Air Liquide, it will have a separate plant number, B7419, and a separate application, No. 13678.

The ConocoPhillips Carbon Plant, Plant A0022, is owned and operated by ConocoPhillips. It is contiguous to the refinery. Although it has a separate plant number and Title V permit, it is also considered part of the facility. The applicant will reduce emissions at the carbon plant to obtain reductions in actual emissions of PM10 for the purposes of CEQA and contemporaneous offsets of SO2.

The list of equipment at the proposed Air Liquide plant is shown below:

- S1, Hydrogen Plant, 120 MMscf/day, including HRSG and steam turbine generator (12 MW)
- S2, Hydrogen Plant Furnace, 1,072 MMbtu/hr abated by A1, SCR
- S3, Hydrogen Plant Flare, 2200 MMbtu/hr
- S4, Cooling Tower, 3,700 gpm
- S5, Ammonia Tank, 10,000 gal-19% aqueous ammonia

A1, Selective Catalytic Reduction Unit abating S2, Hydrogen Plant
Furnace

S4, Cooling Tower, is exempt from permits because BAAQMD Regulation 2-1-128.4 exempts water cooling towers provided that the source does not require permitting pursuant to BAAQMD Regulation 2-1-319. This section would require permits if the source emits more than 5 tons per year of any regulated air pollutant. Some large cooling towers emit enough POC or PM10 to require permits. This cooling tower will have permit conditions requiring monitoring to ensure that the emissions of POC and PM10 each do not exceed the amounts stated in the application.

S5, Ammonia Tank, is exempt from permits because BAAQMD Regulation 2-1-113.2 exempts vessels used exclusively for the storage of any aqueous solution containing less than 1% organic compounds by weight provided that the source does not require permitting pursuant to BAAQMD Regulation 2-1-319. This section would require permits if the source emits more than more than 5 tons per year of any regulated air pollutant or the source emits more than the trigger level for any toxic air contaminant. The tank is a pressure tank and is unlikely to emit more than the trigger level of ammonia (7,700 lb) in any year.

Air Liquide will use the excess heat generated at the hydrogen plant to make steam and will provide steam to ConocoPhillips. This will enable ConocoPhillips to shut down an older 256 MMbtu/hr boiler, S8. Air Liquide will also use steam to power a steam turbine to generate electricity for its own use and for ConocoPhillips. A maximum of 12 MW will be generated; 4.5 MW will be used by the new hydrogen plant. ConocoPhillips will use the remainder.

2. EMISSIONS

Following is a summary of the proposed emissions of NO_x, SO₂, PM₁₀, POC, and CO in tons per year from the proposed Air Liquide hydrogen plant. The annual emissions are calculated for the average operating rate of 975 MMBtu/hr. The maximum daily emissions are calculated for the maximum operating rate of 1,072 MMBtu/hr.

Summary of Hydrogen Plant Emissions

Source	Tons per Year				
	NO _x	SO ₂	PM ₁₀	POC	CO
New SMR Furnace	28.1	5.0	15.8	11.5	34.2
Deaerator Vent	--	--	--	0.8	--
Flare Pilots/NG Purge	0.12	0.004	--	--	1.1
Startup/Shutdown	2.7	0	0	0.1	11
Cooling Tower			0.5	1.5	
Fugitives	--	--	--	1.5	--
Total	30.9	5.0	16.3	15.4	46.2

(975 MMBtu/hr, annual average)

Source	Lb per Day				
	NO _x	SO ₂	PM ₁₀	POC	CO
New SMR Furnace	169	30	95	69	206
Deaerator Vent	--	--	--	4.4	--
Flare Pilots/NG Purge	0.68	0.022	--	--	5.9
Cooling Tower			2.5	8	
Fugitives	--	--	--	8.2	--
Total	170	30	97.5	89.9	212

(1072 MMBtu/hr, hourly maximum)

Air Liquide has calculated the maximum daily emissions for the flare. If the pressure swing absorption process malfunctions, up to 6.41 MMscf/hr of syngas could be sent to the flare for 4.8 hours/event. The composition of syngas is mainly hydrogen, methane, and CO, as shown below:

PROPOSED-March 13, 2007

Evaluation Report, Application No. 13678, Air Liquide Large Industries US L.P., Facility B7459

Component	% by Weight	% by Volume
Hydrogen	13.4	73
Nitrogen	0.2	<0.09
Carbon Dioxide	68.5	17
Carbon Monoxide	10.3	4
Methane	7.3	5
Ethane	<0.001	<0.0001
Water	0.3	0.2

In this case, approximately 686 lb NOx/day would be emitted and 3,537 lb CO/day would be emitted. In this case, the hydrogen plant and hydrogen plant furnace would shut down, so normal emissions would not be emitted concurrently with the flare emissions.

	Lb per Highest Day				
Source	NOx	SO2	PM10	POC	CO
Flare	686	0	negligible	0	3,537

The detailed calculations of the flare emissions are in Appendix A.

Following is the detail of the emissions of toxic air contaminants on which the health risk screening analysis was based. These emissions were based on a heat input rate of 1,100 MMBtu/hr to S2, Hydrogen Plant Furnace. The average hourly rate has been reduced to 975 MMBtu/hr, so the typical emissions will be lower. Also the proposed emissions of methanol have been reduced to 0.61 lb/day or 223 lb/yr. Emission factors from WSPA/API's Air Toxic Emission Factors for Combustion Sources Using Petroleum-Based Fuels, final report, Volume 2, Appendix B, April 14, 1998 have been used for the calculations of all emissions from the heater except ammonia and sulfuric acid mist. The ammonia calculations are based on the "ammonia slip", the ammonia that is lost when injected into A1, SCR, for NOx control. The sulfuric acid mist is based on the assumption that the ratio of SO2 to SO3 in combustion is 20:1, and that all SO3 becomes sulfuric acid mist. The detailed calculations are in Appendix B of the engineering evaluation for Application 13424.

Substance	Emissions (lb/yr)						
	S2, Hydrogen Plant Furnace	Flare Pilots	Deaerator Vent	Cooling Tower ^a	Hydrogen Plant Fugitives	Total Annual Emissions (lb/yr)	BAAQMD Trigger Level (lb/yr)
	Acenaphthene	2.27E-02					2.27E-02
Acenaphthylene	1.49E-02					1.49E-02	
Acetaldehyde	1.47E+02	2.02E-01				1.48E+02	6.40E+01
Acrolein		4.69E-02				4.69E-02	2.30E+00
Ammonia	4.82E+04		5.59E+03		0.00E+00	5.38E+04	7.70E+03
Antimony	4.98E+00					4.98E+00	7.70E+00
Arsenic	8.19E+00					8.19E+00	1.20E-02
Benzene	6.23E+02	7.46E-01				6.24E+02	6.40E+00
Benzo(a)anthracene	3.09E-01					3.09E-01	0.011 ^b
Benzo(a)pyrene	8.63E-01					8.63E-01	0.011 ^b
Benzo(b)fluoranthene	3.89E-01					3.89E-01	0.011 ^b
Benzo(k)fluoranthene	2.32E-01					2.32E-01	0.011 ^b

Substance	Emissions (lb/yr)							BAAQMD Trigger Level (lb/yr)
	S2, Hydrogen Plant Furnace	Flare Pilots	Deaerator Vent	Cooling Tower ^a	Hydrogen Plant Fugitives	Total Annual Emissions (lb/yr)		
	1,3-Butadiene					4.84	4.84E+00	
Cadmium	9.52E+00					9.52E+00	4.50E-02	
Chlorine				3.95E-02		3.95E-02	7.70E+00	
Chloroform				9.94E+00		9.94E+00	3.40E+01	
Chromium (Total)	1.03E+01					1.03E+01	1.30E-03	
Chrysene	1.57E-02					1.57E-02		
Copper	4.06E+01					4.06E+01	9.30E+01	
Ethylbenzene	2.91E+02	6.78E+00				2.98E+02	7.70E+04	
Fluoranthene	2.95E-02					2.95E-02		
Fluorene	1.04E-01					1.04E-01		
Formaldehyde	1.07E+03	5.48E+00				1.08E+03	3.00E+01	
n-Hexane		1.36E-01			7.50E+00	7.63E+00	2.70E+05	
Indeno(1,2,3-cd)pyrene	9.93E-01					9.93E-01	0.011*	
Lead	4.71E+01					4.71E+01	5.40E+00	
Manganese	6.56E+01					6.56E+01	7.70E+00	
Mercury	1.73E+00					1.73E+00	5.60E-01	
Methanol			1.75E+04 2.23+02			1.75E+04	1.50E+05	
Naphthalene	3.02E+00	6.57E-02				3.08E+00	5.30E+00	
Nickel	9.08E+01					9.08E+01	7.30E-01	
Phenanthrene	1.41E-01					1.41E-01		
Phenol	5.43E+01					5.43E+01	7.70E+03	
Propylene	2.09E+01	1.14E+01				3.24E+01	1.20E+05	
Pyrene	2.39E-02					2.39E-02		

Substance	Emissions (lb/yr)							BAAQMD Trigger Level (lb/yr)
	S2, Hydrogen Plant Furnace	Flare Pilots	Deaerator Vent	Cooling Tower ^a	Hydrogen Plant Fugitives	Total Annual Emissions (lb/yr)		
	Selenium	1.89E-01					1.89E-01	
Silver	1.55E+01					1.55E+01		
Sulfuric Acid Mist	8.6E+02					8.6E+02	3.9E+01	
Toluene	1.03E+03	2.72E-01				1.03E+03	1.20E+04	
1,2,4-Trimethylbenzene								
Xylene (Total)	3.59E+02	1.36E-01				3.60E+02	2.70E+04	
Zinc	2.00E+02					2.00E+02	1.40E+03	

^a Chloroform emissions from the cooling tower were calculated using an emission factor of 0.0034 lb CHCl₃ per lb of Cl₂ used to chlorinate the cooling waters. Emission factor is from *Proposed Identification of Chloroform as a Toxic Air Contaminant* (CARB, September 1990. http://www.arb.ca.gov/toxics/summary/chloroform_A.pdf). Cl₂ usage based on bleach density of 10 lb/gal, 12.5 wt% NaOCl (avg. of 9-16% bleach solution), 0.3 lb Cl₂/gal.

^bThese substances are PAH derivatives that have OEHHA-developed Potency Equivalency Factors. These PAHs should be evaluated as benzo(a)pyrene equivalents. This evaluation process consists of multiplying individual PAH-specific emission levels with their Potency Equivalency Factor, which is 0.1. The sum of these products is the benzo(a)pyrene equivalent level and should be compared to the benzo(a)pyrene equivalent trigger level.

This table shows the average hourly emissions of toxic air contaminants:

Substance	Emissions (lb/hr)						BAAQMD Trigger Level (lb/hr)
	SMR Furnace	Flare Pilots	Deaerator Vent	Cooling Tower	Hydrogen Plant Fugitives	Total Hourly Emissions (lb/hr)	
	Acenaphthene	3.07E-06					

Substance	Emissions (lb/hr)						BAAQMD Trigger Level (lb/hr)
	SMR Furnace	Flare Pilots	Deaerator Vent	Cooling Tower	Hydrogen Plant Fugitives	Total Hourly Emissions (lb/hr)	
	Acenaphthylene	2.02E-06					
Acetaldehyde	1.99E-02	2.30E-05				1.99E-02	
Acrolein		5.36E-06				5.36E-06	4.20E-04
Ammonia	6.50E+00		6.40E-01		0.00E+00	7.14E+00	7.10E+00
Antimony	6.72E-04					6.72E-04	
Arsenic	1.11E-03					1.11E-03	4.20E-04
Benzene	8.41E-02	8.52E-05				8.42E-02	2.90E+00
Benzo(a)anthracene	4.17E-05					4.17E-05	
Benzo(a)pyrene	1.16E-04					1.16E-04	
Benzo(b)fluoranthene	5.25E-05					5.25E-05	
Benzo(k)fluoranthene	3.13E-05					3.13E-05	
1,3-Butadiene					5.53E-04	5.53E-04	
Cadmium	1.28E-03					1.28E-03	
Chorine				4.50E-06		4.50E-06	4.60E-01
Chloroform				1.13E-03		1.13E-03	3.30E-01
Chromium (Total)	1.39E-03					1.39E-03	
Chrysene	2.12E-06					2.12E-06	
Copper	5.47E-03					5.47E-03	2.20E-01
Ethylbenzene	3.93E-02	7.73E-04				4.00E-02	
Fluoranthene	3.98E-06					3.98E-06	
Fluorene	1.40E-05					1.40E-05	
Formaldehyde	1.44E-01	6.26E-04				1.45E-01	2.10E-01
n-Hexane		1.55E-05			8.56E-04	8.72E-04	
Indeno(1,2,3-cd)pyrene	1.34E-04					1.34E-04	

Substance	Emissions (lb/hr)						BAAQMD Trigger Level (lb/hr)
	SMR Furnace	Flare Pilots	Deaerator Vent	Cooling Tower	Hydrogen Plant Fugitives	Total Hourly Emissions (lb/hr)	
	Lead	6.36E-03					
Manganese	8.85E-03					8.85E-03	
Mercury	2.34E-04					2.34E-04	4.00E-03
Methanol			2.55-02			2.00E+00	6.20E+01
Naphthalene	4.07E-04	7.50E-06				4.14E-04	
Nickel	1.22E-02					1.22E-02	1.30E-02
Phenanthrene	1.90E-05					1.90E-05	
Phenol	7.32E-03					7.32E-03	1.30E+01
Propylene	2.82E-03	1.31E-03				4.13E-03	
Pyrene	3.22E-06					3.22E-06	
Selenium	2.55E-05					2.55E-05	
Silver	2.09E-03					2.09E-03	
Sulfuric Acid Mist	9.8E-02					9.8E-02	2.6E-01
Toluene	1.39E-01	3.11E-05				1.39E-01	8.20E+01
1,2,4-Trimethylbenzene							
Xylene (Total)	4.85E-02	1.55E-05				4.85E-02	4.90E+01
Zinc	2.70E-02					2.70E-02	

The detailed emission calculations for each source are in Attachment A.

The summary of the emissions for the whole project, which includes Applications No. 13424 for Facility A0016, ConocoPhillips, No. 13678 for Air Liquide, and No. 15328 for contemporaneous offsets from Facility A0022,

PROPOSED-March 13, 2007

Evaluation Report, Application No. 13678, Air Liquide Large Industries US L.P., Facility B7459

ConocoPhillips Carbon Plant, are contained in Application No. 13424. The discussion of emissions for the purposes of PSD applicability, CEQA, offsets, and BACT are also contained in Application No. 13424.

3. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Following are the maximum daily emissions for the various sources:

Source	Lb per Highest Day				
	NOx	SO2	PM10	POC	CO
New SMR Furnace	169	30	95	69	206
Hydrogen Plant	--	--	--	12.6	--
Hydrogen Plant Flare	686				3,537
Cooling Tower			2.5	8	

S1, Hydrogen Plant, is subject to BACT because it emits more than 10 lb/highest day of POC.

S2, Hydrogen Plant Furnace, is subject to BACT because it emits more than 10 lb/highest day of these pollutants: NOx, SO2, POC, CO, and PM10.

S3, Hydrogen Plant Flare, is subject to BACT because it emits more than 10 lb/highest day of these pollutants: NOx and CO.

The following source is not subject to BACT because it will not emit more than 10 lb/day of NOx, SO2, POC, CO, or PM10:

S5, Ammonia Tank

The following source is not subject to BACT because it is exempt from permitting in accordance with BAAQMD Regulation 2-1-128.4.

S4, Cooling Tower

If the source emits more than 5 tons per year of any regulated air pollutant, it would still be subject to permitting in spite of the exemption.

The applicant estimates that emissions of POC will be less than 8.0 lb/day (1.5 tpy) and the emissions of PM10 will be less than 2.5 lb/day. POC levels in cooling towers can spike, however, if there is a leak in a heat exchanger. The permit will contain monitoring conditions to ensure that the POC emissions remain under 5 tons per year. It is far less likely that PM10 emission will be over 5 tons per year, especially with limits on dissolved solids content of the water.

S5, Ammonia Tank, will not have emissions of NOx, SO2, POC, CO, or PM10 and therefore is not subject to BACT.

S1, Hydrogen Plant

The components (valves, flanges, pumps, compressors, etc.) at the hydrogen plant and the deaerator vent are subject to BACT because they are estimated to emit more than 10 lb POC/highest day. BACT for petroleum refinery fugitive emissions in accordance with the Section 3 of the District's BACT handbook is:

- Graphitic gaskets for flanges
- Live loaded packing systems and polished stems, or equivalent, for valves
- "Wet" dual mechanical seals with a heavy liquid barrier fluid, or dual dry gas mechanical seals buffered with inert gas for hydrocarbon centrifugal compressors
- Seal-less design or dual mechanical seals with a heavy liquid barrier fluid, or equivalent, for pumps
- Fugitive equipment monitoring and repair program for all components

BACT for the deaerator vent at hydrogen plants has not been hitherto defined. Air Liquide has proposed 4.35 lb POC/day at the vent. No other hydrogen plants in the Bay Area have mass emission limits on the deaerator vents. Source tests of the vents have shown much higher emissions. No BACT determinations or limits for deaerator vents were found in the EPA, ARB, or SCAQMD BACT Clearinghouses. SCAQMD does have Rule 1189 with a limit of 0.5 lb VOC/MMscf of H₂ produced. This would be equivalent to 60 lb POC/day at the vent.

The above emission rate will be considered to be BACT for this source.

S2, Hydrogen Plant Furnace

Air Liquide has proposed the following BACT levels for S2, Hydrogen Plant Furnace.

PROPOSED-March 13, 2007

Evaluation Report, Application No. 13678, Air Liquide Large Industries US L.P., Facility B7459

Pollutant	Concentration	Emission Factor, lb/MMbtu	Reference for BACT
NOx	5 ppmvd @ 3% O ₂	0.00658	*SCAQMD BACT
SO ₂	35 ppmv total S in RFG/NG	0.0012	BAAQMD BACT (PSA/fuel gas Mix)
PM10	3.8 lb/MMcf (natural gas)	0.0037	AP42 Section 1.4, Natural Gas Combustion (apply 1/2 value since 50% H ₂ in fuel)
POC	2.75 lb/MMcf (natural gas)	0.0027	AP42 Section 1.4, Natural Gas Combustion (apply 1/2 value since 50% H ₂ in fuel)
CO	10 ppmvd @ 3% O ₂	0.0080	SCAQMD BACT

*South Coast Air Quality Management District

These levels are lower than the levels in the District BACT/TBACT handbook. Air Liquide is relying on a top-down analysis of BACT for NOx and PM10 at the hydrogen plant that was performed by ConocoPhillips for Application 13424. This analysis is required as part of the PSD analysis. This analysis is attached in Appendix B. The furnace is compared to various recent hydrogen plant furnaces. These furnaces burn primarily pressure swing absorption gas (PSA gas), which results in lower emissions of NOx and CO than natural gas and refinery fuel gas (RFG). The applicant estimates that this furnace will burn approximately 85% PSA gas and 15% RFG/natural gas.

There are 4 BACT determinations by the SCAQMD for hydrogen plant furnaces with levels for NOx of 5 ppmvd @ 3% O₂. This is the lowest NO_x emission limit achieved in practice. BACT will be achieved by using SCR and by burning mostly PSA gas.

For particulate matter, the conclusion drawn by the top-down analysis was that only good combustion practice is considered to be BACT for controlling PM10 from gas-fired heaters. The level proposed by the applicant is equivalent to 0.0025 gr/dscf (assuming that the F-factor is the same as the F-factor for natural gas). This is lower than the 0.01 proposed for a 2,088 MMbtu/hr natural gas fired boiler proposed in SCAQMD BACT determination #427061 in 2006.

Also, SCAQMD BACT determination #411357 established that 0.0065 lb PM10/MMbtu was BACT (based on a limit of 3642 lb/mo, 780 MMbtu/hr, an assumption of 720 hr/mo. operation). Air Liquide has proposed 0.0037 lb PM10/MMbtu for this application.

For SO₂, the level proposed compares favorably with the 40 ppm S in fuel as H₂S in SCAQMD BACT determination #411357 for a 780 MMbtu/hr steam reformer furnace with similar fuels, and very favorably with the 0.2 lb/MMbtu level in SCAQMD BACT determination #427061 for a 2,088 natural gas-fired boiler.

The proposed CO concentration of 10 ppm@ 3% O₂ is equivalent to the last SCAQMD BACT determination #411357.

For POC, SCAQMD BACT determination #411357 determined that 0.0061 lb POC/MMbtu was BACT (based on a limit of 3399 lb/mo, 780 MMbtu/hr, an assumption of 720 hr/mo operation). Air Liquide has proposed 0.0027 lb POC/MMbtu for this application.

The District concludes that the levels proposed for S2, Hydrogen Plant Furnace, represent BACT.

Air Liquide is relying on a top-down analysis of BACT for NO_x and PM₁₀ at the hydrogen plant furnace that was performed by ConocoPhillips for Application 13424. This analysis is required as part of the PSD analysis. The analysis is attached in Appendix B.

Air Liquide has also proposed a maximum emission rate during start-up, shutdown, and malfunction of 50 lb NO_x/clock hour.

S3, Hydrogen Plant Flare

The main purpose of the flare is to dispose of hydrogen and CO in an emergency for safety reasons. Hydrogen is not a pollutant.

The flare's emissions on the highest day may be up to 686 lb NO_x/day and 3,537 lb CO/day, as shown in the flare calculations in Appendix A. However, the flare will only be used occasionally when there is a shutdown, malfunction, during maintenance, or when there is a sudden drop in the refinery's use of hydrogen. The total annual emissions from the flare are estimated at 2.7 tpy NO_x and 11 tpy CO. There are also small ongoing emissions from the flare pilots, which ensure that a flame is present at all times. Because the emissions of NO_x and CO will be more than 10 lb/day on the highest day, the flares are subject to BACT.

The District's BACT/TBACT Workbook states that an enclosed ground level flare with a control efficiency of 98.5% for POC is BACT1. BACT1 for CO is undetermined at this point.

The applicant has stated that the flare is not subject to BACT for POC because the gases sent to the flare do not contain more than 10 lb POC/day. Following is the gas composition:

Component	% by Weight	% by Volume
Hydrogen	13.4	73
Nitrogen	0.2	<0.09
Carbon Dioxide	68.5	17
Carbon Monoxide	10.3	4
Methane	7.3	5
Ethane	<0.001	<0.0001
Water	0.3	0.2

Because none on the components is considered to be POC, the flare is not subject to BACT for POC.

As shown in the flare calculations, the flare is a control device for CO and a generator of NOx. The calculations assume 98% control of CO.

Testing is not feasible for elevated flares because they are open and have no stack. If the flare were enclosed, it might be possible to test for destruction efficiency. It is likely that if the flare were enclosed, NOx emissions would rise and CO emissions would drop due to increased residence time. It is not sensible to specify an enclosed ground level flare simply to enable testing. Moreover, enclosed ground level flares are generally small. For example, the largest enclosed ground level flare at a landfill in the District, where these flares are commonly used, in the District has a capacity of 120 MMbtu/hr.

Due to the capacity of this flare (2,220 MMbtu/hr), District staff concluded that a ground-level enclosed flare was not feasible in this case. The facility will install an elevated flare. These flares are considered to have a control efficiency of 98% for CO.

4. CUMULATIVE INCREASE AND OFFSETS

The cumulative increase for the facility is shown below.

	Tons per Year				
	NOx	SO2	PM10	POC	CO
Total	30.9	5.0	15.8*	13.9*	46.2

*The emissions from the exempt cooling tower at the hydrogen plant are not considered to be part of the cumulative increase and are not subject to offsets.

Offsets are required by BAAQMD Regulation 2-2-302 for NO_x and POC because the emissions of the facility, which includes the Conoco refinery (Facility A0016) and the Conoco carbon plant (Facility A0022), will be greater than 35 tons per year. The refinery emitted approximately 335 tons NO_x and 283 tons POC and the carbon plant emitted approximately 532 tons NO_x in 2005 according to District estimates.

In accordance with BAAQMD Regulation 2-2-302.2, POC credits shall be used to offset part of the NO_x increases.

Offsets are required by BAAQMD Regulation 2-2-303 for SO₂ and PM₁₀ at major facilities. Conoco is a major facility for PM₁₀ because the refinery emitted approximately 126 tons PM₁₀ and the carbon plant emitted approximately 63 tons PM₁₀ in 2005 according to District estimates. It is a major facility for SO₂ because the refinery emitted approximately 424 tons SO₂ and the carbon plant emitted approximately 1212 tons SO₂ in 2005 according to District estimates.

The discussion of offsets required and provided for this project can be found in the engineering evaluation for Application 13424.

5. STATEMENT OF COMPLIANCE

BAAQMD Regulation 1, General Provisions

The District requires NO_x CEMs from sources that use SCR for control, therefore S2, Hydrogen Plant Furnace, is subject to 1-521 and 1-522. The source will also be required to have a CO CEM.

S2, Hydrogen Plant Furnace, will be subject to flow and ammonia injection monitoring and therefore will be subject to the parametric monitoring requirements in Section 1-523.

BAAQMD Regulation 2, Rule 1, General Requirements

S4, Cooling Tower, is exempt from permits because BAAQMD Regulation 2-1-128.4 exempts water cooling towers provided that the source does not require permitting pursuant to BAAQMD Regulation 2-1-319. This section would require permits if the source emits more than more than 5 tons per year of any regulated air pollutant. Some cooling towers emit enough POC or PM₁₀ to require permits. This cooling tower will have permit conditions requiring monitoring to ensure that the emissions of POC and PM₁₀ each do not exceed the amounts stated in the application, which were 1.5 tons per year and 0.5 tons per year, respectively.

S5, Ammonia Tank, 10,000 gal, is not required to have a permit because the storage of aqueous solutions that contains less than one percent by weight organic compounds is exempt in accordance with Section 123.2. The tank will be a pressure vessel with a nitrogen blanket. It will store 19% aqueous ammonia. The ammonia concentration will be limited to 19% because storage of higher concentrations is subject to 40 CFR 68, Accidental Release.

BAAQMD Regulation 2, Rule 5, New Source Review Of Toxic Air Contaminants

In accordance with BAAQMD Regulation 2, Rule 5, health risk assessment analysis was prepared by the facility and reviewed by District Staff. The project risk, including Plant A0016, ConocoPhillips refinery, meets the requirements as follows:

- Project cancer risk is less than 10.0 in a million;
- Project chronic hazard index is less than 1.0; and
- Project acute hazard index is less than 1.0.

The cancer risk for S2, Hydrogen Plant Furnace, is greater than 1.0 in a million. Therefore, the source is subject to TBACT in accordance with Section 2-5-301 of the rule. TBACT is the use of extremely clean fuels. Approximately 85% of the fuel that will be burned in the Heater will be PSA gas, which is extremely clean and has very little sulfur.

Also, the risk assessment for S2 is conservative, because it was based on an average heat input rate of 1,100 MMbtu/hr, but the final average heat input rate will be 975 MMbtu/hr, which is 12.8% less.

The chronic health index for all sources is below 0.2.

BAAQMD Regulation 6, Particulate Matter and Visible Emissions

The following sources are the new sources of particulate matter in this application:

- S2, Hydrogen Plant Furnace abated by A1, SCR
- S3, Hydrogen Plant Flare, 2200 MMbtu/hr
- S4, Cooling Tower, 3,700 gpm

S2, Hydrogen Plant Furnace, and A1, SCR, are subject to Sections 6-301, 6-305, and 6-310.3 of the regulation. Section 6-301 is a requirement that visible emissions may not exceed 1.0 Ringelmann for more than 3 min/hr. Section 6-305 is a requirement that a unit may not emit visible particles that fall outside of the facility's property. Section 6-310.3 is the grain-loading limit for heat transfer operations of 0.15 gr filterable particulate/dscf @ 6% O₂. (The "gr" used in this

section means "grains," which are equal to 1/7000 of a pound.) S2 burns gaseous fuels and is expected to comply with these requirements.

S3, Hydrogen Plant Flare, is subject to Sections 6-301, 6-305, and 6-310 of the regulation. Section 6-310 is the general grain-loading limit of 0.15 gr filterable particulate/dscf. S3 burns gases and is expected to comply with these requirements.

S4, Cooling Tower, is subject to Sections 6-301, 6-305, 6-310, and 6-311 of the regulation. The cooling tower is expected to comply with these requirements. Previous analysis for Application 10349 shows that, for cooling towers, the amount of particulate matter is so small and the airflow is so large that compliance with 6-301, 6-310, and 6-311 is assured.

Compliance with Section 6-311 is on a process weight basis. The flow rate of water for the cooling tower is 3,700 gal/min. This is equivalent to 1.85 million lb/hr. If the process weight is over 57,320 lb/hr, the limit is 40 lb filterable particulate/hr. The emission rate shown in the calculations in Appendix A is 0.1 lb/hr, therefore the source will comply with Section 6-311.

BAAQMD Regulation 7, Odorous Emissions

The purpose of Regulation 7 is the general control of odorous compounds. Most odorous pollutants are handled generally. A few are mentioned by name. One of these is ammonia.

S1 Hydrogen Plant, and S2, Hydrogen Plant Furnace, are sources of ammonia. Section 7-303 limits concentration of ammonia from Type A emission points to 5000 ppm. Ammonia is used at S2 in the SCR for abatement of NOx. The hydrogen plant will emit up to 10 ppm of ammonia from the deaerator vent. The heater will comply because it has a limit of 10 ppmv ammonia @ 3% oxygen, as will the hydrogen plant because the concentration at the vent is low. The concentration of ammonia in the stacks of both sources will be measured by source test after construction.

BAAQMD Regulation 8, Rule 2, Miscellaneous Operations

The deaerator vent at the Hydrogen Plant, S1, and the cooling tower, S4, will be subject to this rule. Section 301 has the following limit:

"A person shall not discharge into the atmosphere from any miscellaneous operation an emission containing more than 6.8 kg. (15 lbs.) per day and containing a concentration of more than 300 PPM total carbon on a dry basis."

If the emissions at the deaerator meet 4.35 lb/day as stated by the applicant, the deaerator will comply easily. Annual source tests will be required to ensure compliance.

Cooling towers are exempt from this rule, in accordance with Section 8-2-114, if best modern practices are used. The District has determined "best modern practices" for cooling towers and has documented them in the engineering evaluation for ConocoPhillips' Application 10349 as follows:

"... daily visual inspection, plus water sampling and analysis for indicators of hydrocarbon leaks once per shift, is the best modern practice."

S4, Cooling Tower, will not comply with best modern practices, and therefore is subject to Regulation 8, Rule 2. The engineering evaluation also determined that the margin of compliance for most refinery cooling towers is 1000:1. Therefore, the cooling tower will comply with Regulation 8, Rule 2.

BAAQMD Regulation 8, Rule 10, Process Vessel Depressurization

The Hydrogen Plant, S1, will be subject to this rule. Section 301 of the rule requires that the emissions during depressurizing be controlled by an abatement device or the fuel gas system until the vessel is as close to atmospheric pressure as possible, but at least until the partial pressure of organic compounds in that vessel is less than 4.6 psig.

Section 302 requires that no process vessel may be opened to the atmosphere unless the internal concentration of total organic compounds has been reduced prior to release to atmosphere to less than 10,000 parts per million (ppm), with the following exception. Vessels may be opened when the concentration of total organic compounds is 10,000 ppm or greater provided that the total number of such vessels opened with such concentration during any consecutive five year period does not exceed 10% of the total process vessel population, the organic compound emissions from the opening of these vessels does not exceed 15 pounds per day and the vessels are not opened on any day on which the APCO predicts an exceedance of a National Ambient Air Quality Standard for ozone or declares a Spare the Air Day.

S1 is expected to comply with these requirements.

BAAQMD Regulation 8, Rule 18, Equipment Leaks

The components-valves, flanges, pumps, compressors, pressure relief devices-are subject to this rule. The rule has total organic leak limits of 100 ppm for valves and flanges and 500 ppm for pumps, compressors, and pressure relief devices. This is a "work-practice" standard. The facility is obligated to test the components for leaks on a periodic basis and repair the leaks. A small

percentage of non-repairable leaks are allowed until the next turnaround or five years, whichever is sooner.

The facility will have an inspection program for this regulation and is expected to comply with these standards.

BAAQMD Regulation 8, Rule 28, Episodic Releases from Pressure Relief Devices at Petroleum Refineries and Chemical Plants

This regulation applies to pressure relief devices (PRDs) installed on refinery equipment. Section 8-28-302 applies to PRDs on new or modified equipment. It requires that these PRDs comply with all requirements of BAAQMD Regulation 2, Rule 2, including BACT. BACT1 at this time is a rupture disk with a vent to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98%. All new PRDs installed pursuant to this project are subject to this standard. The applicant has determined that the use of rupture disks is not feasible at the hydrogen plant because of the high number of pressure cycles and high temperatures. The hydrogen plant will be required to comply with BACT2, the requirement to vent to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98%.

Permit conditions with the BACT requirement will be added to these units. The facility is expected to comply with this requirement.

BAAQMD Regulation 9, Rule 1, Sulfur Dioxide

S2, Hydrogen Plant Furnace, and S3, Hydrogen Plant Flare, are small sources of SO₂ emissions. These sources are not subject to the 300-ppm limit in Section 9-1-301 of the rule because the refinery complies with the exemption in Section 9-1-110. The exemption requires ground level monitoring and compliance with the ground level concentration limit.

BAAQMD Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations

S2, Hydrogen Plant Furnace, is subject to the rule because it applies to new heat transfer operations with a maximum heat input greater than 250 MMbtu/hr, per Section 9-3-303. The source will easily comply with the 125 ppm limit for gaseous fuels because it is designed to comply with the 5 ppm @ 3% O₂ BACT limit.

BAAQMD Regulation 9, Rule 10, Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries

S2, Hydrogen Plant Furnace, is not subject to this regulation because it applies to affected units. Affected units are defined by Section 9-10-220 as "any petroleum refinery boiler, steam generator, or process heater... having an Authority to Construct or a Permit to Operate prior to January 5, 1994." This heater will be subject to current BACT limits for NO_x and CO, which are more stringent, instead of the Regulation 9, Rule 10, limits.

BAAQMD Regulation 12, Rule 11, Flare Monitoring at Petroleum Refineries and BAAQMD Regulation 12, Rule 12, Flares at Petroleum Refineries

S1, Hydrogen Plant, will have a hydrogen plant flare for the purpose of flaring hydrogen and pressure swing absorption gas if there is an upset. BAAQMD Regulation 12, Rules 11 and 12, apply to petroleum refineries, which are defined for the purposes of the rule as:

"A facility that processes petroleum, as defined in the North American Industrial Classification Standard No. 32411 and including any associated sulfur recovery plant."

Because the hydrogen plant will not process petroleum, the hydrogen plant flare will not be subject to BAAQMD Regulation 12, Rules 11 and 12. The flare will be used exclusively to burn hydrogen, pressure swing absorption gas that is generated by the plant, and natural gas in the pilots for the flare. All three of these material are low in sulfur because the feed to the hydrogen plant is low in sulfur and sulfur is removed from the feed by a zinc oxide catalyst. If the feed to the hydrogen plant or the hydrogen plant furnace must be flared due to an upset, it will be burned in the refinery flares.

NSPS

Subpart D

This subpart applies to fossil-fuel fired steam generating units with a heat input over 250 MMbtu/hr. The definition of fossil-fuel fired steam generating unit in Section 60.41(a) is "a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer." S2, Hydrogen Plant Furnace, is not subject to 40 CFR 60, Subpart D, because it is primarily a furnace instead of a steam generating unit, although it does generate steam. In any case, S2 would easily comply with the 0.1 lb particulate matter/MMbtu standard in Section 60.42(a)(1) the 20% opacity standard in Section 60.42(a)(2), and the 0.2 lb NO_x/MMbtu. S2 is expected to emit about 0.0037 lb PM₁₀/MMbtu and 0.00658 lb NO_x/MMbtu. Since the fuel will be very clean, it is not expected to have any visible emissions.

The standard does not contain a limit for sulfur dioxide for gaseous-fueled heaters.

Subpart Da

This subpart applies to electric utility steam-generating units with an electrical output that is higher than 25 MW per Sections 60.40Da and 60.41Da. Electricity will be generated at the hydrogen plant, but the output will be about 10.4 MW so S2, Hydrogen Plant Furnace, is not subject to the standard.

Subpart Db

This subpart applies to steam generating units with a heat input over 100 MMbtu/hr. The definition of steam generating units in Section 60.41b excludes process heaters, so S2, Hydrogen Plant Furnace, is not subject to the standard.

Subpart Dc

This subpart applies to steam generating units with a heat input over 10 MMbtu/hr and under 100 MMbtu/hr. The definition of steam generating units in Section 60.41c excludes process heaters, so S2, Hydrogen Plant Furnace, is not subject to the standard.

NSPS, Subpart J

S2, Hydrogen Plant Furnace, and S3, Flare, will be subject to 40 CFR 60, Subpart J, Standards of Performance for Petroleum Refineries because they it will burn fuel gas as defined by the NSPS: "any gas which is generated at a petroleum refinery and which is combusted."

The heater will be subject to the H₂S limit for fuel in Section 60.104(a)(1) of 0.10 gr/dscf or approximately 160 ppm. S2 will comply with the limit because it will burn either complying refinery fuel gas that will be supplied by the refinery, natural gas, or PSA gas, which is derived from the complying refinery fuel gas or natural gas and therefore cannot contain more H₂S than the limit.

Air Liquide will be responsible for continuously monitoring the H₂S content of the refinery, natural gas, and PSA gas at S2, Hydrogen Plant Furnace, as required by Section 60.105(a)(4). The permit conditions will also allow Air Liquide to install an SO₂ CEM instead of monitoring the sulfur in the furnace and hydrogen plant feed as allowed by 40 CFR 60.105(a)(3).

The flare will also be subject to the H₂S limit for fuel in Section 60.104(a)(1). The standard states:

- a) No owner or operator subject to the provisions of this subpart shall:
 - (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

Process upset gases are defined in Section 60.101 as:

Process upset gas means any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

When the hydrogen plant sends gases to the flare due to a start-up, shut-down, upset or malfunction, the flare will not be subject to Section 60.104(a)(1). However, when the hydrogen plant sends gases to the flare due to "customer constraint", "contractual outage", or planned maintenance, the flare will be subject.

In any case, the flare will comply with the standard because it will only burn clean hydrogen or PSA gas. In those cases where the flare is subject to the standard, the facility will be required to monitor the H₂S content of the gas continuously in accordance with Section 60.104, unless the facility obtains an alternative monitoring plan from USEPA.

EPA intends to propose changes to Subpart J in April 2007, and finalize changes by April 2008. If these changes allow the facility to monitor the H₂S content in a different way or exempts some fuels from monitoring, the permit condition will allow Air Liquide to take advantage of changes in the standard when the changes are finalized.

MONITORING ANALYSIS

S1, Hydrogen Plant is subject to an annual throughput limit, cumulative increase limits of 4.35 lb POC/day from the deaerator vent and 8.2 lb fugitive POC/day, an ammonia limit of 0.64 lb/hr from the deaerator vent, and a limit on total sulfur in the feed to the hydrogen plant. The hydrogen plant is also subject to the combined organic compound limit in BAAQMD Regulation 8, Rule 2. The hydrogen plant will be subject to an annual source test to determine compliance with the deaerator vent limits. The owner/operator will determine compliance with the fugitive POC limit by using the methods in BAAQMD Regulation 8, Rule 18, Equipment Leaks. The total sulfur content of the feed to the hydrogen plant will be determined once per week at the outlet of the zinc oxide feed treatment system in the hydrogen plant by taking a grab sample and measuring it once per week. Alternately, the owner/operator may install an SO₂ CEM on S2, Hydrogen Plant Furnace stack. Sulfur in the hydrogen plant feed is removed by the zinc oxide feed treatment system. The plant has two beds of zinc oxide and monitors sulfur at the outlet periodically. If the sulfur is removed from the feed, the syngas (PSA gas) that is fed to the hydrogen plant furnace and that provides approximately 85% of the heat input to the furnace should have no sulfur. Therefore, monitoring for sulfur in the feed is an effective method of ensuring that the syngas has no sulfur. Since the amount of zinc oxide should last at least nine months, monitoring on a weekly basis is sufficient monitoring. The owner/operator also has the option of installing an SO₂ CEM on the S2, Hydrogen Plant Furnace, stack.

S2, Hydrogen Plant Furnace, has limits on hourly and annual heat input, concentration limits on NO_x, CO, and NH₃, lb/MMbtu limits on POC, SO₂, and PM₁₀, hourly and annual mass emission limits on NO_x, CO, POC, PM₁₀, and SO₂, NH₃, and sulfuric acid mist, and sulfur and H₂S limits on the fuel. The heater will have a fuel meter to ensure compliance with the heat input limits. Since the heater is abated by SCR, it will have a NO_x CEM to ensure that the abatement device is in compliance. A CO CEM is required by 40 CFR 63, Subpart DDDDD. The fuel gas will be monitored for H₂S with a continuous emission monitor as required by 40 CFR 60, Subpart J, unless EPA amends the standard to allow another monitoring method. In addition, total sulfur will be monitored 3 times/day. The owner/operator will perform an annual test for compliance with the POC, PM₁₀, SO₂, sulfuric acid mist, and ammonia limits. Non-compliance with the POC and PM₁₀ limits are not expected at this source. Since the source will be permitted to emit about 24 tpy of ammonia, the owner/operator will develop a correlation between the ammonia concentration and the ammonia injection rate. After the correlation is developed, the owner/operator will monitor ammonia continuously via the injection rate.

S3, Hydrogen Plant Flare

The flare is subject to annual limits for NO_x, CO, POC, PM₁₀, SO₂ and a daily limit for NO_x. Emissions will be monitored by installing a flow meter at the inlet to the flare and calculating the emissions for each event in the same manner as shown in Appendix A.

If gases are sent to the flare that are considered to be startup, shutdown, malfunction, or upset gases, the facility must monitor the gases continuously for H₂S in accordance with 40 CFR 60.104.

In addition, the flare is subject to standard conditions to determine if the 1.0 Ringelmann limit in BAAQMD Regulation 6-301 is exceeded during flaring events.

S4, Cooling Tower, is subject to monitoring of dissolved solids to ensure that the particulate matter emissions are as described in the permit application. It is also subject to visual monitoring, and chlorine content monitoring to ensure that POC emissions are as described. If POC emissions are found, the owner/operator must measure the POC emissions using EPA Laboratory Method 8015.

S5, Ammonia Tank: The tank is not expected to have emissions, so no monitoring has been imposed.

Overall annual emission limits have been imposed in Condition 23181, parts B.1-B.3, to ensure that the emissions of the project are less than the emissions proposed by the applicant. The reason that this condition has been imposed is to allow the facility to exceed certain limits during startup and shutdown and still

comply with the annual limits. Part B.4 contains the monitoring and reporting for these limits.

CEQA

The California Environmental Quality Act (CEQA) calls for a review of potential significant environmental impacts from proposed projects. This project has been determined to be subject to CEQA by the Contra Costa County Community Development Department (CCCCDD). The CCCCDD is the Lead Agency for CEQA for this project. In accordance with Regulation 2-1-310.3, the District may not issue an Authority to Construct for this project until final action has been taken by the Lead Agency. A draft Environmental Impact Report (EIR) was prepared by the CCCCDD in November, 2006. This EIR includes all sources and activities that are the subject of this application. The District is a responsible agency under CEQA and has provided comments to the CCCCDD on the draft EIR. These comments, as well as others received by CCCCDD have been addressed in a revised EIR.

(To be completed after appeal period.)

On _____, the final EIR was certified by the Contra Costa County Planning Commission. On _____, a mandatory 10-day appeal period for the EIR ended. Thus, the District may issue an Authority to Construct for this project.

NESHAPS

40 CFR 63, Subpart CC

The deaerator vents at the hydrogen plants are not considered miscellaneous process vents according to Section 60.641.

Relief valve discharges are not considered miscellaneous process vents.

40 CFR 63, Subpart DDDDD

S2, Hydrogen Plant Furnace, is subject to 40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. The emission limit is 400 ppm CO. There are no other limits for gaseous-fueled boilers. The standard also requires continuous CO monitoring.

40 CFR 70, Title V

The facility is subject to the Title V program because it is part of a major facility (the ConocoPhillips Refinery and Carbon Plant) as defined by BAAQMD Regulation 2-6-206. The definition of "Part 70 permit" in Section 70.2 acknowledges that a "group of permits" may cover a "source." (EPA's definition

PROPOSED-March 13, 2007

Evaluation Report, Application No. 13678, Air Liquide Large Industries US L.P., Facility B7459

of "source" is similar to the District's definition of "facility.") Because more than one permit may be given to a facility, the District may grant a separate permit to Air Liquide.

The District will propose the Title V permit after the District has received public comment on and finalized the conditions.

40 CFR 72-78, ACID RAIN

Electricity will be generated using excess heat at the hydrogen plant. The hydrogen plant will not be subject to 40 CFR 72-78 because it will not sell electricity. The hydrogen plant or ConocoPhillips will consume all electricity that is produced. The standards apply only to "utilities," which are defined in 40 CFR 72.2 as "any person who sells electricity."

PSD

The discussion of the PSD analysis is contained in the engineering evaluation for Application 13424 and is hereby incorporated by reference.

6. RECOMMENDATIONS

Issue a conditional authority to construct for the following sources:

- S1, Hydrogen Plant (120 MMscf/day) including HRSG and steam turbine generator (12 MW)
- S2, Hydrogen Plant Furnace, 1072 MMbtu/hr abated by A1, SCR
- S3, Hydrogen Plant Flare, 2200 MMbtu/hr

Issue a letter of exemption to the following sources:

- S4, Cooling Tower, 3,700 gpm (exempt per BAAQMD Regulation 2-1-128.4)
- S5, Ammonia Tank, 10,000 gal 19% aqueous solution (exempt per BAAQMD Regulation 2-1-113.2)

7. PERMIT CONDITIONS

Any condition that is preceded by an asterisk is not federally enforceable.

CONDITION 23178

S1, Hydrogen Plant

1. The production of S1, Hydrogen Plant, shall not exceed 120 MMscf H₂/day, averaged over any consecutive 12-months. [Cumulative Increase]
2. The owner/operator of the electrical generator associated with the hydrogen plant shall not generate more than 12 MW at any time. The owner/operator shall ensure that the hydrogen plant or the refinery consumes all of the electricity that is produced by the generator. [2-1-301, 2-1-305]
3. The owner/operator shall not burn any fuel in the HRSG associated with the S1, Hydrogen Plant. [2-1-301, 2-1-305]
4. The owner/operator shall ensure that the emissions of POC from the deaerator vent at S1 do not exceed 4.35 lb/day. [2-1-301, 2-1-305, Cumulative Increase]
5. The owner/operator shall ensure that the emissions of NH₃ from the deaerator vent at S1 do not exceed 0.64 lb/hr. [Toxics Risk Management]
6. The owner/operator shall ensure that the fugitive emissions of POC from the components (valves, flanges, pumps, compressors, connectors, sample points, etc.) at the hydrogen plant do not exceed 3,000 lb/year. [Cumulative Increase, 2-1-305]

7. The owner/operator shall ensure that the concentration of total sulfur in the feed to the hydrogen plant does not exceed 35 ppmv. [Cumulative Increase, 2-1-305]
 8. The owner/operator shall measure total sulfur at the outlet of the zinc oxide feed treatment system in the hydrogen plant by taking a grab sample and measuring it once per week. Alternately, the owner/operator may install an SO₂ CEM on S2, Hydrogen Plant Furnace stack. [BACT, Cumulative Increase]
 9. No later than 90 days from the startup of S1 and every year thereafter, the owner/operator shall conduct a District-approved source test to determine compliance with the limit in Parts 4 and 5 for POC and NH₃. The owner/operator shall conduct the POC source tests in accordance with the Manual of Procedures, Volume IV, Method ST-7 or EPA Method 25 or 25A. The owner/operator shall conduct the NH₃ source tests in accordance with the Manual of Procedures, Volume IV, Method ST-1B. The owner/operator shall submit the source test results to the District staff no later than 60 days after the source test. [Cumulative Increase, 2-1-305]
 10. The owner/operator shall ensure that all pressure relief devices on the process unit are vented to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98%. [8-28-302, BACT]
- Fugitive Components at S1, Hydrogen Plant, and S2, Hydrogen Plant Furnace
11. The owner/operator shall equip all new light hydrocarbon control valves installed at S1 and S2 with live loaded packing systems and polished stems, or equivalent.
[BACT]
 12. The owner/operator shall equip all new flanges/connectors installed in the light hydrocarbon piping systems at S1 and S2 with graphitic-based gaskets unless the service requirements prevent this material. [BACT]
 13. The owner/operator shall equip all new hydrocarbon centrifugal compressors installed at S1 and S2 with "wet" dual mechanical seals with a heavy liquid barrier fluid, or dual dry gas mechanical seals buffered with inert gas.
[BACT]
 14. The owner/operator shall equip all new light hydrocarbon centrifugal pumps installed at S1 and S2 with a seal-less design or with dual mechanical seals with a heavy liquid barrier fluid, or equivalent. [BACT]
 15. The owner/operator shall establish a facility fugitive equipment monitoring and repair program in accordance with BAAQMD Regulation 8, Rule 18.
[BACT, Regulation 8, Rule 18]

16. The Owner/Operator shall submit a count of installed pumps, compressors, valves, and flanges/connectors every 180 days starting the startup date of the first unit, S1 or S2, until construction is complete. For flanges/connectors, the owner/operator shall also provide a count of the number of graphitic-based and non-graphitic gaskets used. The owner/operator has been permitted to install fugitive components (948 valves in gas service, 48 valves in light liquid service, 4,193 flanges in gas service, 98 flanges in light liquid service, 5 pumps in light liquid service, 4 sample connections in gas service, 3 compressors in gas service) with a total POC emission rate of 1.5 ton/yr. If there is an increase in the total fugitive component emissions, the plant's cumulative emissions for the project shall be adjusted to reflect the difference between emissions based on predicted versus actual component counts. The owner/operator shall provide to the District all additional required offsets at an offset ratio of 1.15:1 no later than 14 days after the submittal of the final POC fugitive equipment count. If the actual component count is less than the predicted, at the completion of the project, the total will be adjusted accordingly and all emission offsets applied by the owner/operator in excess of the actual total fugitive emissions will be credited back to owner/operator prior to issuance of the permits. [BACT, Cumulative Increase, Toxic Management]

17. In order to determine compliance with part 6, the owner/operator shall determine the daily emissions of fugitive components within 90 days of start-up, and within 30 days of the end of every calendar quarter thereafter. The owner/operator shall use the last concentration measured in accordance with BAAQMD Regulation 8, Rule 18, for each component. The owner/operator shall use the equations in ARB publication California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities. [Cumulative Increase, 2-1-305]

CONDITION 23179

S2, Hydrogen Plant Furnace

1. S2 shall use only pressure swing adsorption (PSA) off gas, refinery fuel gas and pipeline quality natural gas as fuel. [Cumulative Increase, PSD]

2. Total fuel firing at S2 shall not exceed 9,636,000 MMbtu (HHV) over any consecutive 12-month period. [Cumulative Increase, PSD]

3. Total fuel firing at S2 shall not exceed 1,072 MMbtu (HHV) during any clock hour. [Cumulative Increase, PSD]

4. The owner/operator shall ensure that the feed to S2 does not contain more than 35 ppmv total sulfur. [BACT, Cumulative Increase, 2-1-305]

5. The following emission concentration limits from S2 shall not be exceeded. These limits shall not apply during startup periods not exceeding 24 hours (72 hours when drying refractory or during the first startup following catalyst

replacement) and shutdown periods not exceeding 24 hours. The District may approve other startup and shutdown durations.

- a. NOx: 5 ppmv @ 3% oxygen, averaged over any clock hour [BACT, PSD]
 - b. CO: 10 ppmv @ 3% oxygen, averaged over any 1 hour period [BACT]
 - c. POC: 0.0027 lb/MMbtu, averaged over any 1 hour period [BACT]
 - d. PM10: 0.0037 lb/MMbtu, averaged over any 1 hour period [BACT, PSD]
 - e. SO2: 0.0012 lb/MMbtu, averaged over any 1 hour period [BACT]
6. *The following emission concentration limits from S2 shall not be exceeded.
NH3: 10 ppmv @ 3% oxygen (8 hr average) [Toxic Management]
- 7a. The following hourly mass emission limits from S2 shall not be exceeded. These limits shall not apply during startup periods not exceeding 24 hours (72 hours when drying refractory or during the first startup following catalyst replacement) and shutdown periods not exceeding 24 hours. The District may approve other startup and shutdown durations.
- a. NOx: 7.5 lb per clock hour [BACT, PSD]
 - b. CO: 9.1 lb per clock hour [BACT]
 - c. POC: 3.5 lb per clock hour [BACT]
 - d. PM10: 4.8 lb per clock hour [BACT, PSD]
 - e. SO2: 1.5 lb per clock hour [BACT]
- 7b. The following hourly mass emission limit from S2 shall not be exceeded.
- a. NOx: 50 lb per clock hour [BACT, PSD]
- [BACT]
8. *The following hourly mass emission limit from S2 shall not be exceeded.
- a. NH3: 6.5 lb per clock hour [Toxic Management]
9. The following hourly mass emission limit from S2 shall not be exceeded.
- a. Sulfuric acid mist: 0.098 lb per clock hour [Toxic Management, PSD]
10. The following annual mass emission limits from S2 shall not be exceeded including periods of startup, shutdown, upset and malfunction:
- a. NOx: 28.1 tons per any consecutive 12 months [BACT, PSD]
 - b. CO: 34.2 tons per any consecutive 12 months [BACT]
 - c. POC: 11.5 tons per any consecutive 12 months [BACT]
 - d. PM10: 15.8 tons per any consecutive 12 months [BACT, PSD]
 - e. SO2: 5.0 tons per any consecutive 12 months [BACT]
- [Cumulative Increase]
11. *The following annual mass emission limits from S2 shall not be exceeded including periods of startup, shutdown, upset and malfunction.

- a. NH₃: 48,200 lb per any consecutive 12 months
[Toxic Management]
- 12. The following annual mass emission limits from S2 shall not be exceeded including periods of startup, shutdown, upset and malfunction.
 - a. Sulfuric acid mist: 860 lb any consecutive 12 months
[2-1-305, Toxic Management, PSD]
- 13. A1, SCR unit, shall abate the S2, Hydrogen Plant Furnace, at all times, with the following exceptions. Operation of A1 is not required for limited periods during startup and shutdown. S2 may operate without SCR abatement on a temporary basis for periods of planned or emergency maintenance. A District-approved NO_x CEM shall monitor and record the S2 NO_x emission rate whenever S2 operates without abatement. All emission limits applicable to S2 shall remain in effect even if it is not operated with SCR abatement. [BACT, Cumulative Increase]
- 14a. The owner/operator shall test refinery fuel gas prior to combustion at S2 to determine total sulfur concentration with a total sulfur analyzer (Houston Atlas or equivalent) at least once per 8-hour shift (3 times per calendar day). At least 90% of these samples shall be taken each calendar month. No readable samples or sample results shall be omitted. To demonstrate compliance with Part 4, the owner/operator shall measure and record the daily average sulfur content. The owner/operator shall keep records of sulfur content in fuel gas for at least five years and shall make these records available to the District upon request. The owner/operator is not required to test PUC-quality natural gas for total sulfur. If the sulfur content of feed to S1, Hydrogen Plant, is monitored in accordance with Condition 23178, part 8, and the sulfur content is less than 35 ppmv, the owner/operator is not required to test PSA gas for total sulfur. [BACT, Cumulative Increase]
- 14b. If the owner/operator elects to install a SO₂ CEM at the S2, Hydrogen Plant Furnace, stack, the owner/operator is not required to perform the monitoring in Condition 23178, parts 7 and 8 and Condition 23179, parts 4, 14a, and 15. In this case, the monitor shall comply with BAAQMD Manual of Procedures, Volume V, and 40 CFR 60.105(a)(3). The monitor shall be used to determine compliance with the SO₂ limit in 40 CFR 60.105(a)(3) of 20 ppmd @ 0% O₂, and the hourly limit in part 7a.
- 15. The owner/operator shall install, calibrate, maintain, and operate a District-approved continuous monitoring system and recorder for H₂S in the gas that is burned by the heater. The owner/operator shall keep the H₂S data for at least five years and shall make these records available to the District upon request. If USEPA amends 40 CFR 60, Subpart J, such that a continuous monitoring system is not required for this heater, the owner/operator will not be required to install the system. If the system has been installed, the owner/operator may remove the system. [40 CFR 60.105(a)(4), Cumulative Increase]

16. No later than 90 days from the startup of S2, the owner/operator shall conduct District-approved source tests to determine initial compliance with the limits in Parts 5, 6, 7, 8, and 9 for NO_x, CO, POC, PM₁₀, NH₃, SO₂, sulfuric acid mist, and POC. The owner/operator shall conduct the source tests in accordance with Part 18. The owner/operator shall submit the source test results to the District source test manager and the District Director of Compliance and Enforcement no later than 60 days after the source test. [BACT, Cumulative Increase, PSD]
17. On an annual basis, the owner/operator shall conduct District-approved source tests to determine compliance with the limits in Parts 5c, 5d, 5e, 7c, 7e, 7e, 8, and 9 for POC, PM₁₀, NH₃, SO₂, and sulfuric acid mist. The owner/operator shall conduct the source tests in accordance with Part 18. The owner/operator shall submit the source test results to the District source test manager and the District Director of Compliance and Enforcement no later than 60 days after the source test. [BACT, Cumulative Increase, PSD, Toxics Risk Management]
18. The owner/operator shall submit protocols for all source test procedures to the District's Source Test Section prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emissions monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section, in writing, of the source test protocols and projected test dates at least 7 days prior to testing. [BACT, Cumulative Increase, PSD]
19. The following instruments shall be installed and maintained to demonstrate compliance with Parts 5a, 5b, 7a, 7b, 9a and 9b, BAAQMD Regulation 1-520 and 40 CFR 63, Subpart DDDDD:
 - a. continuous NO_x analyzer/recorder
 - b. continuous CO analyzer/recorder
 - c. continuous O₂ or CO₂ analyzer/recorderThe instruments shall operate at all times of operation of S2 including start-up, shutdown, upset, and malfunction, except as allowed by BAAQMD Regulation 1-522, BAAQMD Manual of Procedures, Volume V, and 40 CFR 63, Subpart DDDDD. If necessary to comply with this requirement, the owner/operator shall install dual-span monitors. [1-520, BACT, Cumulative Increase, 40 CFR 63.7500, PSD]
20. The owner/operator shall equip S2 with a District-approved continuous fuel flow monitor and recorder in order to determine fuel consumption. A parametric monitor as defined in Regulation 1-238 is not acceptable. The owner/operator shall keep continuous fuel flow records for at least five years and shall make these records available to the District upon request. [Cumulative Increase]
21. Ammonia (NH₃) emission concentrations at the hydrogen plant stack shall not exceed 10 ppmv, on a dry basis, corrected to 3% O₂, on a clock hour

basis. This ammonia emission concentration shall be verified by the continuous recording of the ammonia solution injection rate to A1, SCR. The correlation between the heat input rates, the SCR ammonia solution injection rates, and corresponding ammonia emission concentration at the hydrogen plant stack shall be determined in accordance with permit condition 23. (Toxics Risk Management for NH₃)

22. The owner/operator shall demonstrate compliance with part 21 by using a properly operated and maintained continuous monitor (during all hours of operation including start-up and shutdown periods) for the ammonia solution injection rate. The owner/operator shall record the ammonia solution injection rate every 15 minutes (excluding normal calibration periods) and shall summarize the ammonia solution injection rate for each clock hour. (Toxics Risk Management for NH₃)
23. Within 60 days of start-up of the hydrogen plant furnace, the owner/operator shall conduct a District-approved source test on at the hydrogen plant stack to determine the corrected ammonia emission concentration to determine compliance with part 21. The source test shall determine the correlation between the heat input rates of the hydrogen plant furnace, the ammonia solution injection rate, and the corresponding ammonia emission concentration at the emission point. The source test shall be conducted over the expected operating range of the hydrogen plant furnace to establish the range of ammonia solution injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. Source testing shall be repeated on an annual basis thereafter. Ongoing compliance with part 21 shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia solution injection rate. Source test results shall be submitted to the District within 45 days of conducting the tests. (Toxics Risk Management for NH₃)
24. The owner/operator shall comply with the applicable requirements of 40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. (This part will be deleted after the Title V permit is issued.) [40 CFR 63, Subpart DDDDD]

CONDITION 23180

S3, Hydrogen Plant Flare

1. The owner/operator shall ensure that only the following streams are sent to S3, Hydrogen Plant Flare:
 - a. Hydrogen
 - b. Syn-gas
 - c. Venting from the ammonia tank
 - d. PSA Offgas

The owner/operator shall ensure that any feed for S1, Hydrogen Plant, or any fuel including natural gas that is provided to S2, Hydrogen Plant Furnace, is not flared in S3, Hydrogen Plant Flare.

2. The owner/operator shall ensure that S3, Hydrogen Plant Flare, is only used during startup, shutdown, upset, or malfunction of S1, Hydrogen Plant.
3. The owner/operator shall install a flow meter to determine the flow of gases to the flare. The flow meter shall comply with the requirements for flow meters in BAAQMD Regulation 12, Rule 11. [Cumulative increase]
4. The owner/operator shall ensure that the emissions of S3, Hydrogen Plant Flare, do not exceed the following limits:
 - a. NOx: 2.8 tons/any consecutive 12 months
 - b. CO: 12.1 tons/any consecutive 12 months
 - c. NOx: 129 lb/any consecutive 60 minutes
5. The owner/operator shall estimate the emissions every month by using the flow data to the flare and estimating emissions using the emission factors provided in Application 13678.
6. If the limits in parts 4a and 4b are exceeded, the owner/operator shall apply to increase the annual limit within 60 days of determining that the limit has been exceeded, shall provide offsets for the increase in the limits. If the limit in part 4c is exceeded, the owner/operator shall determine using PSD modeling if the CAAQS or NAAQS for NO₂ was exceeded during the event, and if so, shall report the exceedance to the BAAQMD Director of Enforcement and Compliance.
7. For the purposes of these conditions, a flaring event is defined as a flow rate of vent gas flared in any consecutive 15 minutes period that continuously exceeds 330 standard cubic feet per minute (scfm). If during a flaring event, the vent gas flow rate drops below 330 scfm and then increases above 330 scfm within 30 minutes, that shall still be considered a single flaring event, rather than two separate events. For each flaring event during daylight hours (between sunrise and sunset), the owner/operator shall inspect the flare within 15 minutes of determining the flaring event, and within 30 minutes of the last inspection thereafter, using video monitoring or visible inspection following the procedure described in Part 8. [Regulation 2-6-409.2]
8. The owner/operator shall use the following procedure for the initial inspection and each 30-minute inspection of a flaring event.
 - a. If the owner/operator can determine that there are no visible emissions using video monitoring, then no further monitoring is necessary for that particular inspection.

- b. If the owner/operator cannot determine that there are no visible emissions using video monitoring, the owner/operator shall conduct a visual inspection outdoors using either:
 - i. EPA Reference Method 9; or
 - ii. Survey the flare by selecting a position that enables a clear view of the flare at least 15 feet, but not more than 0.25 miles, from the emission source, where the sun is not directly in the observer's eyes.
 - c. If a visible emission is observed, the owner/operator shall continue to monitor the flare for at least 3 minutes, or until there are no visible emissions, whichever is shorter.
 - d. The owner/operator shall repeat the inspection procedure for the duration of the flaring event, or until a violation is documented in accordance with Part 9. After a violation is documented, no further inspections are required until the beginning of a new calendar day.
[Regulation 6-301, 2-1-403]
9. The owner/operator shall comply with one of the following requirements if visual inspection is used:
- a. If EPA Method 9 is used, the owner/operator shall comply with Regulation 6-301 when operating the flare.
 - b. If the procedure of Part 8.b.ii is used, the owner/operator shall not operate a flare that has visible emissions for three consecutive minutes.
[Regulation 2-1-403]
10. The owner/operator shall keep records of all flaring events, as defined in Part 7. The owner/operator shall include in the records the name of the person performing the visible emissions check, whether video monitoring or visual inspection (EPA Method 9 or visual inspection procedure of Part 8) was used, the results of each inspection, and whether any violation of this condition (using visual inspection procedure in Part 8) or Regulation 6-301 occurred (using EPA Method 9). [Regulation 2-1-403]
11. The owner/operator will ensure that S3, Flare, complies with all applicable provisions of 40 CFR 60, Subpart J. This provision will be deleted when the applicable citations from this standard are incorporated into the Major Facility Review permit. [40 CFR 60, Subpart J]

CONDITION 23181

A. Facility Conditions

- 1. *The owner/operator shall notify the District in writing by fax or email no less than three calendar days in advance of any scheduled startup or shutdown of any process unit, and, for any unscheduled startup or shutdown of a process unit, within 48 hours or within the next normal business day. The notification shall be sent in writing by fax or email to the Director of Enforcement and Compliance. This requirement is not federally enforceable.
[Regulation 2-1-403]

2. The owner/operator shall ensure that the concentration of ammonia in the ammonia tank is less than 20% by weight so that 40 CFR 68, Accidental Release, does not apply. [2-1-305]

B. Project Mass Emission Limits

1. Following are the sources that are subject to the project mass emission limits:
S1, Hydrogen Plant including HRSG and steam turbine generator
S2, Hydrogen Plant Furnace
S3, Hydrogen Plant Flare
2. The owner/operator shall ensure that the annual emissions of the above sources do not exceed the following annual emission limits, including periods of startup, shutdown, malfunction, and upset emissions.
 - a. NOx 30.9 tpy
 - b. SO2 5.0 tpy
 - c. PM10 15.8 tpy
 - d. POC 13.9 tpy
 - e. CO 46.2 tpy
 - f. Sulfuric acid mist 0.43 tpy
 - g. Ammonia 26.9 tpy
3. The owner/operator shall ensure that the daily emissions of the above sources do not exceed the following daily emission limit, including periods of startup, shutdown, malfunction, and upset emissions.
 - a. Sulfuric acid mist 2.35 lb/day [PSD]
4. The owner/operator shall determine whether the emissions are below the allowable mass emissions for the above sources as shown below. The owner/operator calculate and report the emissions of NOX, SO2, PM10, POC, CO, ammonia, and sulfuric acid mist on an annual basis in the following manner.
 - a. The owner/operator shall the use the POC emission rate determined by the annual source test data at the deaerator for S1.
 - b. The owner/operator shall use the data generated by the BAAQMD Regulation 8, Rule 18, monitoring to determine the annual POC emission rate for the components.
 - c. The owner/operator shall use the mass emissions data generated by the NOx and CO CEMs at S2.
 - d. The owner/operator shall use the monitoring for total sulfur in the feed to the hydrogen plant.
 - e. The owner/operator shall use the monitoring for total sulfur in the feed to the hydrogen plant furnace.
 - f. The owner/operator shall use the emission rates of sulfuric acid mist, PM10, POC, and CO determined in annual ~~and semi-annual~~ source tests at S245 and the records of heat input to calculate emissions of sulfuric acid mist, PM10, POC, and CO.
 - g. The owner/operator shall use the ammonia injection monitoring and the records of heat input to calculate emissions of ammonia.

- h. The owner/operator shall use the calculations of flare emissions required by BAAQMD Condition 23180, part 5. [2-1-305]
5. If the annual emissions, as determined in part B.4, are above the allowable emissions for the project, the owner/operator shall supply additional offsets, where applicable, and perform additional analysis for PSD, if necessary. The results of the analysis shall be submitted to the Director of Compliance and Enforcement on an annual basis on the anniversary of the startup of S2, Hydrogen Plant Furnace.

The owner/operator shall comply with the requirements of BAAQMD Regulation 8, Rule 18. (This part will be deleted after the Title V permit is issued.) [BAAQMD Regulation 8, Rule 18]

CONDITION 23414

S4, Cooling Tower

1. The owner/operator shall ensure that the cooling tower is designed to have a drift of no more than 0.005% of total cooling water flow. [Cumulative Increase]
2. The owner/operator shall ensure that the dissolved solids content in the cooling water at S4, Cooling Tower, does not exceed 3000 ppm total dissolved solids. [Cumulative Increase]
3. The owner/operator shall take a sample and perform a visual inspection of the cooling tower water at the cooling tower on a daily basis to check for signs of hydrocarbon in the cooling water. (Regulation 2-6-503)
4. The owner/operator shall take a sample of the cooling tower water 3 times per week at the cooling tower and analyze for chlorine content as an indicator of hydrocarbon leakage into the cooling water. On a monthly basis, the owner/operator shall sample the water in the inlet line and in the return line of the cooling tower and determine the VOC content in each line using EPA laboratory method 8015. (Regulation 2-6-503)
5. The owner/operator shall maintain monthly records of sodium hypochlorite usage at each cooling tower above. (Regulation 2-6-501)
6. The owner/operator shall sample the cooling tower water at least once per month and subject the sample to a District approved laboratory analysis to determine its total dissolved solids content. (Regulations 2-6-503)
7. If the monitoring in part 3 or part 4 indicates that there is a hydrocarbon leak into the cooling water, the owner/operator shall submit a report to the Enforcement and the Engineering divisions at the District. The owner/operator shall submit reports on a weekly basis until the monitoring

indicates that no hydrocarbon leaks into the cooling water.
(Regulation 1-441)

6. If the monitoring in part 3 or part 4 indicates a hydrocarbon leak, the owner/operator shall estimate the daily amount of VOC emitted using the following procedure. The owner/operator shall sample the water in the inlet line and in the return line and determine the VOC content in each line using EPA laboratory method 8015. This analysis shall be performed each week until VOC levels return to normal. The owner/operator shall report the VOC estimates to the Enforcement and the Engineering divisions at the District on a monthly basis. The owner/operator shall use the VOC estimates to confirm that no more than 5 tons VOC per year was emitted at the source. If more than 5 tons VOC per year is emitted at the source, the facility shall submit an application for a District permit within 90 days of determining that the source is subject to District permits. If the source requires a permit, the source shall be subject to BACT and offsets. (Regulations 1-441, 2-1-424, 2-6-416.2, 2-6-501, 2-6-503)
7. The owner/operator shall maintain the following records for five years from the date of record:
 - a. Records of daily visual inspection
 - b. Records of chlorine content 3 times per week
 - c. Records of monthly usage of sodium hypochlorite
 - d. Records of monthly determination of total dissolved solids
 - e. Records of any indications of hydrocarbon leaks
 - f. Records of any analyses of VOC content in cooling tower inlet and outlet(Regulation 2-6-501)

By: _____

Brenda Cabral
Supervising Air Quality Engineer

Date

PROPOSED-March 13, 2007

Evaluation Report, Application No. 13678, Air Liquide Large Industries US L.P., Facility B7459

APPENDIX A

PROPOSED-March 13, 2007

Evaluation Report, Application No. 13678, Air Liquide Large Industries US L.P., Facility B7459

S1, Hydrogen Plant Emissions

The detailed calculations are available in electronic format upon request.

S2, Hydrogen Plant Furnace Emissions

The following emission calculations have been submitted by the applicant.

Hydrogen Plant Furnace Criteria Pollutant Emission Factors
Air Liquide Hydrogen Plant Operational Emissions

Pollutant	Emission Factor	EF (lb/MMBtu)	Reference
NOx	5 ppmvd @ 3% O ₂	0.00658	SCAQMD BACT
SO ₂	35 ppmv total S in RFG/NG	0.0012	BAAQMD BACT (PSA/fuel gas Mix)
PM10	3.8 lb/MMcf (natural gas)	0.0037	AP42 Section 1.4, Natural Gas Combustion (apply 1/2 value since 50% H2 in fuel)
POC	2.75 lb/MMcf (natural gas)	0.0027	AP42 Section 1.4, Natural Gas Combustion (apply 1/2 value since 50% H2 in fuel)
CO	10 ppmvd @ 3% O ₂	0.0080	SCAQMD BACT

Assumptions for emissions factor table above:

(1) NOx, CO, and NH3 "ppm" emission factors converted to "lb/MMBtu" as follows:

$$(x \text{ [lb/MMBtu]}) = (y \text{ ppm @ 3\% O}_2) * (21\% - 0\%) / (21\% - 3\%) * (\text{EPA Fd Factor [ft}^3\text{/MMBtu]}) / (\text{Molar Volume [ft}^3\text{/lbmol]}) * (\text{Molecular weight [lb/lbmol]})$$

PM10 and POC "lb/MMcf" emission factors converted to "lb/MMBtu" as follows:

$$(x \text{ [lb/MMBtu]}) = (\text{Emission factor [lb/MMcf]}) / (\text{Natural gas heat content [Btu/scf]})$$

PROPOSED-March 13, 2007

Evaluation Report, Application No. 13678, Air Liquide Large Industries US L.P., Facility B7459

Fd Factor: 9290 ft³/MMBtu (Air Liquide)
 Molar volume: 379 ft³/lbmol (at STP: 25 C, 1 atm)
 NOx MW: 46 lb/lbmol
 CO MW: 28 lb/lbmol
 NH3 MW: 17 lb/lbmol
 SO2 MW: 64 lb/lbmol
 PSA gas: 235 Btu/scf (ConocoPhillips)
 Refinery Fuel Gas: 1340 Btu/scf (ConocoPhillips 3 year average)
 Natural Gas: 1020 Btu/scf (AP42 basis)

New Hydrogen Plant Furnace Criteria Pollutant Emissions

Criteria Pollutant	Emissions		
	lb/hr ⁽¹⁾	lb/day ⁽¹⁾	ton/yr
NOx	7.1	169	28.1
SO ₂	1.2	30	5.0
PM10	4.0	95	15.8
POC	2.9	69	11.5
CO	8.6	206	34.2

Notes:

(1) Assumed heater rating:

Maximum daily:	1,072	MMBtu/hr
annual:	975	MMBtu/hr
Hydrogen plant capacity:	120	MMscf/day

S3, Hydrogen Plant Flare Emissions

The following emission calculations have been submitted by the applicant.

Estimated Flare Emissions

Air Liquide Hydrogen Plant Operational Emissions

I. NOx and CO Factors

0.0641 lb NOx/MMBtu (TCEQ factor for non-steam assist, low-Btu flare, LHV)
0.5496 lb CO/MMBtu (TCEQ factor for non-steam assist, low-Btu flare, LHV)
98% DRE for CO

II. Summary

Source	Pollutant	lb/hr	tpy
Pilot/Sweep Emissions	NOx	0.03	0.12
	CO	0.24	1.07
	SO2	0.0004	0.004

III. Calculations

A. Pilot Emissions

4 Pilots
91.9 scfh/pilot, Natural Gas
367.6 scfh total for pilots
116.7 scfh sweep gas, Natural Gas

PROPOSED-March 13, 2007

Evaluation Report, Application No. 13678, Air Liquide Large Industries US L.P., Facility B7459

484.3 scfh total for pilots and sweep gas
 919 Btu/scf, Natural Gas LHV
 10 ppmv Sulfur in NG

<u>NOx</u>										
484.3	scf NG	919	Btu	0.0641	lb NOx	1	MMBtu	=	0.028529	lb NOx
	hr		scf NG		MMBtu	1000000	Btu			hr
0.03	lb NOx	8760	hr	1	ton			=	0.124957	tons NOx
	hr		yr	2000	lb					yr
<u>CO</u>										
484.3	scf NG	919	Btu	0.5496	lb CO	1	MMBtu	=	0.244611	lb CO
	hr		scf NG		MMBtu	1000000	Btu			hr
0.24	lb CO	8760	hr	1	ton			=	1.071398	tons CO
	hr		yr	2000	lb					yr
<u>SO2</u>										
10	ft3 S	484.3	scf NG	1	lbmol S	32	lb S	=	0.000402	lb S
1000000	ft3 NG		hr	385.3	ft3 S		lbmol S			hr
0.0004	lb S	64	lb SO2					=	0.001	lb SO2
	hr	32	lb S							hr
0.00	lb SO2	8760	hr	1	ton			=	0.004	tons SO2
	hr		yr	2000	lb					yr

B. Customer Constraint

2.79 mmscfh of hydrogen

PROPOSED-March 13, 2007

Evaluation Report, Application No. 13678, Air Liquide Large Industries US L.P., Facility B7459

6 events per year
 3.75 hours per event
 274 Btu/scf, HHV Hydrogen

<u>NOx</u> 2.79	mmscf H2 hr	274 MMBtu mmscf	0.0641 lb CO MMBtu	=	49.00 $\frac{\text{lb NOx}}{\text{hr}}$
49.00	lb NOx hr	3.75 hours event	6 events yr	=	0.55 tons NOx yr

C. Loss of PSA

7.74 mmscfh syngas
 0.0516 scf Methane/scf Syngas
 909 Btu/scf, methane
 261.1 Btu/scf, syngas
 835.31 lbmol/hr CO
 28 lb CO/lbmol
 98% DRE for CO
 1 event/yr
 5.3 hrs/event

<u>CO</u> <i>thermal</i> 7.74	mmscf Syngas hr	0.0516 scf Methane scf Syngas	909 MMBtu MMscf	=	199.53 $\frac{\text{lb CO}}{\text{hr}}$
<i>destroyed</i> 835.31	lbmol CO hr	28 lb CO lbmol CO	0.98 DRE	=	467.77 $\frac{\text{lb CO}}{\text{hr}}$

PROPOSED-March 13, 2007

Evaluation Report, Application No. 13678, Air Liquide Large Industries US L.P., Facility B7459

667.30	lb CO	1	event	5.3	hrs	1	ton	=	1.77	tons CO
	hr		yr		event	2000	lbs			yr

NOx

7.74	mmscf Syngas	261.1	MMBtu	0.0641	lb NOx	=	129.54	lb NOx
	hr		MMScf SG		MMBtu			hr

129.54	lb NOx	1	event	5.3	hrs	1	ton	=	0.34	tons NOx
	hr		yr		event	2000	lbs			yr

D. PSA Maintenance

Since the PSA has 12 beds, emissions are estimated by taking 2/12ths of the emissions from losing the entire PSA.

6 events/yr

1 hr/event

NOx	21.59	lb/hr	
	0.06	Tpy	

CO	111.22	lb/hr	
	0.33	Tpy	

E. Plant Maintenance

Maximum flaring will occur when the plant is operating at 50% capacity. Therefore, emissions are estimated by taking 1/2 of the Loss of PSA case.

2 events/yr

9 hrs/event

PROPOSED-March 13, 2007

Evaluation Report, Application No. 13678, Air Liquide Large Industries US L.P., Facility B7459

NOx	64.77	lb/hr
	0.57	tpy
CO	333.65	lb/hr
	2.94	tpy

F. Contractual Outage

Maximum flaring will occur when the plant is operating at 50% capacity. Therefore, emissions are estimated by taking 1/2 of the Loss of PSA case.

4 events/yr
9 hrs/event

NOx	64.77	lb/hr
	1.15	tpy
CO	333.65	lb/hr
	5.94	tpy

Total Estimated Flare Process Emissions

NOx	2.68	tpy
CO	10.98	tpy

S4, Cooling Tower

Table 3-7

Estimated Hydrogen Plant Cooling Tower Emissions

Operations parameter	Value
Tower Capacity, MM gal/day	5.3
Maximum water hardness, ppm TDS	1300
Drift Loss, % of flow capacity ¹	0.0044%
Weight of water, lb/gal	8.34
Maximum PM10 emissions, lb/yr ²	927.7
Maximum PM10 emissions, ton/yr ²	0.46
POC Emission Factor ³	1.50
Maximum POC emissions, lb/day	8.0
Maximum POC emissions, lb/yr	2917
Maximum POC emissions, ton/yr	1.5

¹Vender Estimate

²Calculation method from Section VI (Engineering Evaluation Template) of BAAQMD Permit Handbook Chapters, Cooling Towers

³EPA AP-42 Table 5.1-2. Uncontrolled emission factor is 6 lbs POC/MMgal. Emission factor reduced to 1/4 of referenced value due to POC content of stream.

APPENDIX B

ConocoPhillips Analysis of BACT for NO_x and PM₁₀ for Facility A0016, ConocoPhillips Refinery, and Facility B7459, Air Liquide

Following is ConocoPhillips' review of Best Available Control Technology for S45, Heater, S1004, Sulfur Recovery Unit, and Facility B7149, S2, Heater from Prevention of Significant Deterioration Application submitted on June 2, 2006

4.0 BEST AVAILABLE CONTROL TECHNOLOGY

This section addresses BACT requirements for the proposed ConocoPhillips CFEP, as well as the related new Hydrogen Plant on the Refinery site to be owned and operated by Air Liquide Large Industries U.S. LP.

BAAQMD Rule 2-2-301 requires BACT to be applied to:

“...any new or modified source which results in an emission from a new source, or an increase in emissions from a modified source, and which has the potential to emit 10.0 pounds or more per highest day of precursor organic compounds (POC), non-precursor organic compounds (NPOC), nitrogen oxides (NO_x), sulfur dioxide (SO₂), PM₁₀, or carbon monoxide (CO).”

Proposed controlled emission levels to meet BAAQMD BACT requirements, from recent BAAQMD BACT determinations and the BAAQMD BACT Guidelines (BAAQMD 2005) can be found in the *Clean Fuels Project Application for Authority to Construct and Significant Revision to Major Facility* (ConocoPhillips 2006) and the *Hydrogen Plant Project Application for Authority to Construct and Major Facility Review Permit* (Air Liquide 2005).

Included in BAAQMD Regulation 2, Rule 2, are provisions that implement federal PSD requirements. USEPA policy includes a “top-down” BACT analysis for all pollutants emitted in PSD-significant quantities from new and modified emissions. As described in Section 3.0, PSD requirements apply to NO_x and PM₁₀ in this proposed action. To supplement the BACT analysis presented in the above-referenced BAAQMD Authority to Construct (ATC) Applications, the remainder of this section presents “top-down” BACT analyses for the proposed new and modified sources of NO_x and PM₁₀, based on the USEPA RACT/BACT/LAER Clearinghouse (RBLC), California Air Resources Board (CARB) BACT Clearinghouse, and available information on other recently issued permits. USEPA guidance for a “top-down” BACT analysis requires reviewing all possible control options starting at the top level of control efficiency. In the course of the BACT analysis, one or more options may be eliminated from consideration because they are demonstrated to be technically infeasible or have unacceptable energy, economic, or environmental impacts on a case-by-case (site-specific) basis. The steps required for a “top-down” BACT review are:

1. Identify All Available Control Technologies
2. Eliminate Technically Infeasible Options
3. Rank Remaining Technologies
4. Evaluate Remaining Technologies (in terms of economic, energy, and environmental impacts)
5. Select BACT (the most efficient technology that cannot be rejected for economic, energy, or environmental impact reasons is BACT)

4.1 U246 HEAVY GAS OIL (HGO) FEED HEATER

The proposed new U246 HGO Feed Heater supporting the modified Unit 240/246 Unicracker is proposed to be fired on refinery fuel gas (RFG), with natural gas as a backup fuel. The new HGO Feed Heater would be a natural draft process heater rated at 85 million British thermal units per hour (MMBtu/hr).

4.1.1 NO_x BACT – U246 HGO Feed Heater

1. Identify All Available Control Technologies

Table 3 lists the technologies identified for controlling NO_x emissions from process heaters fired on RFG or natural gas.

Table 3 ***NO_x Control Technologies***

Control Technology
No Controls (Base Case)
Water/Steam Injection
Selective Non-Catalytic Reduction (SNCR)
Combustion Controls (Low-NO _x Burners)
Selective Catalytic Reduction (SCR)
Low-NO _x Burners and SNCR
Low-NO _x Burners and SCR
SCONOX

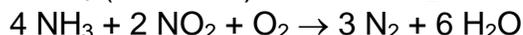
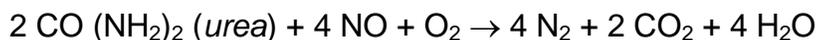
2. Eliminate Technically Infeasible Options

All the control methods identified in Table 3 are considered technically feasible for a process heater fired on RFG, except SCONOx™, SNCR, and water/steam injection.

SCONOx. SCONOx™ uses a potassium carbonate (K₂CO₃) coated catalyst to reduce NO_x emissions. The catalyst oxidizes carbon monoxide (CO) to carbon dioxide (CO₂), and nitric oxide (NO) to NO₂. The CO₂ is exhausted while the NO₂ absorbs onto the catalyst to form potassium nitrite (KNO₂) and potassium nitrate (KNO₃). Dilute hydrogen gas is passed periodically across the surface of the catalyst to convert the KNO₂ and KNO₃ to K₂CO₃, water (H₂O), and elemental nitrogen (N₂), thereby regenerating the K₂CO₃ coating for further absorption. The H₂O and N₂ are exhausted.

SCONOx has not been demonstrated on RFG-fired process heaters (Arizona Department of Environmental Quality [ADEQ] 2005). It has only been demonstrated on combustion sources burning exclusively natural gas. The performance of SCONOx is sensitive to sulfur in the exhaust stream. In addition, the heat ratings on natural gas burners demonstrated with SCONOx are lower than the proposed HGO Feed Heater. Thus, there are significant technical differences between the proposed source and those few sources where SCONOx has been demonstrated in practice. These preclude a finding that SCONOx has been demonstrated to function efficiently on sources identical or similar to the proposed process heater.

Selective Non-Catalytic Reduction (SNCR). SNCR is a post-combustion NO_x control technology based on the reaction of urea or ammonia (NH₃) and NO_x. SNCR involves injecting urea/NH₃ into the combustion gas path to reduce the NO_x to nitrogen and water. This is described by the following chemical equations:



Temperatures ranging from 1,200°F to 2,000°F are required for optimum SNCR performance. Operation at temperatures below this range results in NH₃ slip, while operation above this temperature range results in oxidation of NH₃, forming additional NO_x. Exhaust temperatures of process heaters are typically below the optimum temperature range. In addition, the urea/ammonia must have sufficient residence time, approximately 3 to 5 seconds, at the optimum operating temperatures for efficient NO_x reduction.

SNCR can only be used in induced draft process heaters because of the need to recirculate the flue gas. The HGO Feed Heater will be a natural draft process heater. In addition, existing information on SCNR systems indicate they achieve NO_x reductions ranging from 30 to 75 percent (USEPA 2001), thus SNCR is an

inferior control technology to either SCR or modern combustion controls for an RFG-fired process heater. Therefore, SNCR is considered infeasible for this review.

Water/Steam Injection. The injection of steam or water into the combustion zone can decrease peak flame temperatures, thus reducing thermal NO_x formation. Steam injection is predominantly used with gas turbines. There is little data available to document the effectiveness of water/steam injection for process heaters and no application of this type could be found. Steam injection has been specified as a control method for boilers on a very limited basis. Only one was listed in the USEPA RBLC database during the ADEQ’s recent review of the Arizona Clean Fuels Yuma, LLC project (ADEQ 2005). This review showed a controlled emission rate higher than low NO_x burners produced today. Additionally, there are operating issues concerning flame stability using low NO_x burners with steam injection. Therefore, water/steam injection is considered infeasible for this review.

3. Rank Remaining Technologies

Technically feasible NO_x control technologies are listed in Table 4 with typical emission levels, ranked from most efficient to least efficient.

Combustion Controls. Combustion controls reduce NO_x emissions by controlling the combustion temperature or the availability of oxygen (O₂). These are referred to as “low NO_x burners” or “ultra-low NO_x burners.” There are several designs of low/ultra-low NO_x burners currently available. These burners combine two NO_x reduction steps into one burner, typically staged air with internal flue gas recirculation (IFGR) or staged fuel with IFGR, without any external equipment.

In staged air burners with IFGR, fuel is mixed with part of the combustion air to create a fuel-rich zone. High-pressure atomization of the fuel creates the recirculation. Secondary air is routed by means of pipes or ports in the burner block to optimize the flame and complete combustion. This design is predominantly used with liquid fuels.

Table 4 NO_x Control Hierarchy for Process Heaters Fired on Refinery Fuel Gas

Technology	Typical Emission Level	
	ppmv ¹	lb/MMBtu ²
Combustion Controls and SCR ³	7	0.0085
Selective Catalytic Reduction (SCR)	18	0.022

Combustion Controls	29	0.035
No Controls ⁴	89	0.11

Source: *Petroleum Refinery Tier 2 BACT Analysis Report, Final Report* (EPA, 2001).

¹ Parts per million by volume (ppmv), dry basis, corrected to 3% oxygen.

² Pounds (lbs) of NO_x produced per MMBtu of fuel heat input.

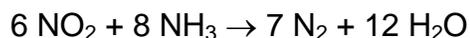
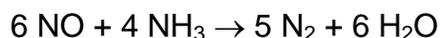
³ Recent data show a range of values, with 7 ppmv representing the low end of current permitted levels on RFG-fired refinery heaters. See discussion of current BACT determinations in text for more details.

⁴ Emission level shown is for a natural draft heater; an induced draft heater would typically have higher uncontrolled NO_x levels, on the order of 179 ppmv at 3% O₂, dry (USEPA 2001). In staged fuel burners with IFGR, fuel pressure induces the IFGR, which creates a fuel lean zone and a reduction in oxygen partial pressure. This design is predominantly used for gas fuel applications.

The range of performance achieved in practice for the best combustion controls is 25 to 29 ppmv at 3% O₂, dry (0.03 to 0.035 lb/MMBtu), with the upper end of range representing heaters firing gas with high hydrogen content (USEPA 2001). Burners that could achieve 10 ppmv or lower are under development, but are not currently available for process heaters.

RFG is high in hydrogen content, so for heaters burning RFG or a mixture of RFG and natural gas, the upper end of the demonstrated range (29 ppmv at 3% O₂, dry, or 0.035 lb/MMBtu) would be appropriate as the achievable performance level for combustion controls on RFG-fired process heaters.

Selective Catalytic Reduction (SCR). SCR is a process that involves post-combustion removal of NO_x from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water by the following reactions:



The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst deactivation due to aging, ammonia slip emissions, and design of the NH₃ injection system. The most common catalysts are composed of vanadium, titanium, molybdenum, and zeolite. Sulfur dioxide and sulfur trioxide are generated in the flue gas when sulfur-containing compounds in fuel are combusted. Catalyst systems promote partial oxidation of sulfur dioxide (from sulfur and mercaptans in the fuel) to sulfur

trioxide, which combines with water to form sulfuric acid, causing corrosion over time. In addition, sulfur trioxide and sulfuric acid reacts with excess ammonia to form ammonium salts. These ammonium salts may condense as the flue gases are cooled, which over time can accumulate on the catalyst causing "plugging" and catalyst deterioration, often referred to as "fouling." These effects can be minimized by proper operation, including:

Controlling the amount of sulfur in the fuel.

Using a properly designed ammonia injection system to maximize the efficient mixing of ammonia and flue gas without colder surfaces present on which ammonium salts can condense.

Operating with the lowest amount of ammonia needed to achieve the desired performance. To achieve high NO_x reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which necessarily results in ammonia slip. Thus, an emissions tradeoff between NO_x and ammonia occurs in high NO_x reduction applications.

Operating at temperatures above the dew point of ammonium salts and sulfuric acid.

Optimal operating temperatures vary by catalyst but generally range from 500 to 800°F. Operating above the maximum temperature results in oxidation of NH₃ to either nitrogen oxides (thereby adding NO_x emissions) or ammonium nitrate. Operating below the optimal temperature increases ammonia slip and catalyst fouling. Refinery process heaters typically operate in the range of 450 to 700°F, thus would be expected to operate above the dew point of ammonium salts and sulfuric acid to minimize fouling and corrosion. SCR systems have been used on process heaters burning mixtures of RFG and natural gas.

SCR systems achieve 80 to 90 percent reductions in NO_x emissions (USEPA 2001). The 90 percent reduction is relative to an uncontrolled induced draft heater since the higher NO_x emissions (approximately 179 ppmv at 3% O₂, dry, or 0.22 lb/MMBtu) versus a natural draft heater (approximately 89 ppmv at 3% O₂, dry, 0.11 lb/MMBtu) provides a greater driving force for increased mass transfer and also enhances the SCR's mechanical draft requirements. This yields an outlet NO_x emission level of approximately 18 ppmv at 3% O₂, dry, or 0.011 lb/MMBtu. For a natural draft heater, maximum SCR control efficiency is on the order of 80 percent due to lower uncontrolled emission rates, yielding approximately the same controlled NO_x emission rate. Thus, a typical achievable performance level for SCR systems on RFG-fired process heaters is 18 ppmv at 3% O₂, dry, or 0.011 lb/MMBtu.

SCR and Combustion Controls. This control option uses SCR downstream of combustion controls to reduce NO_x emissions. With this combination, the inlet NO_x level to the SCR is lower, so lower outlet NO_x can be achieved. However, the SCR may not achieve the same percent reduction performance compared to no upstream combustion controls because of the lower NO_x inlet levels. As is

discussed further below, a review of the USEPA RBLC and CARB BACT Clearinghouse showed permit limits of 7 ppmv NO_x at 3% O₂, dry, as the lowest level achieved in practice on refinery process heaters with SCR and combustion controls fired on a combination of RFG and natural gas. Therefore, the achievable performance level for SCR and combustion controls on RFG-fired process heaters is 7 ppmv at 3% O₂, dry, or about 0.0085 lb/MMBtu.

4. Evaluate Remaining Technologies

Technically feasible technologies are reviewed on a case-by-case basis taking into consideration energy, environmental, and economic impacts beginning with the top option. If the top option is not selected as BACT, the next most effective control is evaluated until it cannot be ruled out for energy, environmental, or economic reasons.

In this case, the top technically feasible control option, SCR with combustion controls, is the proposed control technology. Therefore, the selection of BACT consists of establishing the lowest controlled NO_x emission level achievable with this control technology, taking into consideration the lowest controlled NO_x emissions currently achieved in practice, and if necessary, energy, environmental and economic impacts between different potential controlled emission levels using this technology.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted. These reviews resulted in the lowest NO_x emission limits for refinery heaters fired on RFG/natural gas found in the South Coast Air Quality Management District (SCAQMD). A review of the BACT Determinations published by the SCAQMD provided further details.

There were three SCAQMD BACT Determinations for 7 ppmv NO_x at 3% O₂, dry, documented in the USEPA *Petroleum Refinery Tier 2 BACT Analysis Report* (USEPA 2001) for process heaters burning natural gas or a combination of RFG and natural gas. These were for: (1) Chevron El Segundo Refinery (Permit No. D64697, D62860, D64621); (2) TOSCO Refinery, Wilmington (Application 326118);¹ and (3) CENCO Refinery, Santa Fe Springs (Application 352869).

The ADEQ (2005) recently issued a permit for a similar project, Arizona Clean Fuels Yuma, LLC (ADEQ Permit Number 1001205). In their top-down BACT finding issued on 3 February 2005, the ADEQ summarized the following findings for the highest efficiencies achievable with SCR and combustion controls on RFG-fired process heaters (all 3-hour averages):

High-Efficiency SCR:

NO_x: 0.0085 lb/MMBtu (7 ppmv at 3% O₂, dry)²

¹ Noted in the SCAQMD BACT Determinations to be for a 460-MMBtu/hr Hydrogen Reforming Furnace also combusting Pressure Swing Absorption (PSA) off gas.

² Although the NO_x permit limit for Arizona Clean Fuels Yuma LLC is presented as ppm corrected to 3% O₂, dry, the ADEQ Technical Report presents results in ppm corrected to 0%

Moderate-Efficiency SCR:

NO_x: 0.0125 lb/MMBtu (10 ppmv at 3%O₂, dry)

The ADEQ concluded for Arizona Clean Fuels Yuma LLC that the beneficial environmental impacts of increased NO_x control for the high-efficiency SCR was outweighed by adverse environmental impacts of increased ammonia slip.

Therefore, the NO_x emissions level found to be BACT was 10 ppmv at 3% O₂, dry.

The proposed NO_x emission limit for the ConocoPhillips HGO Feed Heater is 7 ppmv at 3% O₂, dry. This is equivalent to the high-efficiency SCR option that was ruled out by ADEQ, and matches the lowest NO_x emission limit achieved in practice. No further energy, environmental, or economic impact assessment is needed.

5. Select BACT/ Document the Selection is BACT

Based on this review, NO_x BACT is proposed as SCR with combustion controls (low NO_x burners) at 7 ppmv at 3% O₂, dry, or 0.0086 lb/MMBtu.³

4.1.2 PM₁₀ BACT – U246 HGO Feed Heater

1. Identify All Available Control Technologies

Table 5 lists the control technologies identified for controlling PM₁₀ emissions from process heaters fired on natural gas or RFG.

Table 5 PM₁₀ Control Technologies

Control Technology
Good Combustion Practice
Cyclone
Wet Gas Scrubber
Electrostatic Precipitator
Baghouse/Fabric Filters
<u>Good Combustion Practice.</u> By maintaining heaters in good working order and limiting the sulfur in the feed fuels, PM ₁₀ emissions are controlled.
<u>Cyclone.</u> A cyclone operates on the principle of centrifugal force. Exhaust gas enters tangentially at the top of the cyclone and spirals towards the bottom. As

O₂, dry. These have been converted to 3% O₂, dry, for the purposes of the ConocoPhillips analysis.

³ Slight difference from the previous conversions from 7 ppmv at 3% O₂, dry, due to fuel heat value assumptions and/or rounding.

the gas spins, heavier particles hit the outside wall and are collected at the bottom. Cleaned gas escapes through an inner tube.

Wet Gas Scrubber. A wet gas scrubber uses gas/liquid contacting to remove particles primarily by inertial impaction on liquid droplets, followed by collection of the larger liquid droplets as liquid waste.

Electrostatic Precipitator (ESP). An ESP uses an electric field to charge and collect particles in a gas stream, followed by collection of the particles on oppositely charged plates.

Baghouse/Fabric Filter. A baghouse is a metal housing containing many fabric bags. A partial vacuum pulls the dirty air through the fabric bags, filtering the particles from the exhaust stream.

2. Eliminate Technically Infeasible Options

All options in Table 5 are technically feasible.

3. Rank Remaining Technologies

See next (Step 4) discussion.

4. Evaluate Remaining Technologies

While the listed control technologies are all technically feasible, only good combustion practice is used for controlling PM₁₀ emissions from gas-fired heaters. The other technologies are not used because of inherently low PM₁₀ emissions from gaseous fuel combustion. A cyclone would be ineffective in capturing the extremely small particles generated from gaseous fuel combustion, and costs associated with designing the other add-on systems to capture minute particles in low concentrations would be economically infeasible. This is a well-accepted finding of all past BACT determinations for the control of PM₁₀ from combustion of gaseous fuels.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted for currently achieved control levels. Findings were the same as summarized by the ADEQ for the Arizona Clean Fuels Yuma LLC (ADEQ 2005). ADEQ proposed a PM₁₀ emission limit of 0.0075 lb/MMBtu as representative of good combustion practice with gas-fired process heaters, based on the AP-42 emission factor (USEPA 1995a et seq.) for natural gas combustion and typical natural gas heat content. This is consistent with the lowest level achieved in practice.

5. Select BACT/ Document the Selection is BACT

Based on this review, PM₁₀ BACT is proposed as good combustion practice. The USEPA AP-42 natural gas combustion factor was adjusted with the estimated fuel heat content of the proposed RFG/natural gas mixture to calculate a proposed PM₁₀ BACT emission level of 0.0057 lb/MMBtu.

4.2 HYDROGEN PLANT REFORMER Furnace

The proposed new Hydrogen Plant Steam Methane Reformer (SMR) Furnace is proposed to be fired on a mix of approximately 85 percent Pressure Swing Absorption (PSA) off gas and 15 percent RFG/natural gas.

4.2.1 NO_x BACT – Hydrogen Plant Reformer Furnace

1. Identify All Available Control Technologies

The available technologies are the same as listed in Table 3 of Section 4.1.1.

2. Eliminate Technically Infeasible Options

All the control methods identified in Table 3 are considered technically feasible for a Hydrogen Plant Reformer fired on the proposed mix of fuels, except SCONO_x, SNCR, and water/steam injection, for the same reasons provided for a refinery process heater in Section 4.1.1.

3. Rank Remaining Technologies

Technically feasible NO_x control technologies are the same as listed in Table 4 of Section 4.1.1. Since the proposed mix of fuels includes natural and RFG, the emission levels presented in Table 4 can still be considered typical for this application. Inclusion of PSA off gas, however, affects combustion characteristics, and hence, can impact the actual achievable emission levels. Consideration of PSA off gas is included in the following BACT evaluation discussion.

4. Evaluate Remaining Technologies

Technically feasible technologies are reviewed on a case-by-case basis taking into consideration energy, environmental, and economic impacts beginning with the top option. If the top option is not selected as BACT, the next most effective control is evaluated until it cannot be ruled out for energy, environmental, or economic reasons.

In this case, the top technically feasible control option, SCR with combustion controls, is the proposed control technology. Therefore, the selection of BACT consists of establishing the lowest controlled NO_x emission level achievable with this control technology, taking into consideration the lowest controlled NO_x emissions currently achieved in practice, and if necessary, energy, environmental and economic impacts between different potential controlled emission levels using this technology.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted. These reviews resulted in the lowest NO_x emission limits for hydrogen reformer furnaces fired on PSA off gas and RFG/natural gas found in the SCAQMD. A review of the SCAQMD BACT Determinations provided further details.

PSA off gas is high in hydrogen content, and therefore has the potential to form less NO_x and PM₁₀. There were five SCAQMD BACT Determinations for hydrogen reformer furnaces. In reverse chronological order, these NO_x emission limits were: (1) Chevron El Segundo Refinery (Application 411357, 5/19/2004, 5 ppmv at 3% O₂, dry); (2) Praxair, Ontario (Application 389926, 7/17/2002, 5 ppmv at 3% O₂, dry); (3) TOSCO Refinery, Wilmington (Application 326118, 9/9/1999, 7 ppmv at 3% O₂, dry); (4) Chevron El Segundo Refinery (Application 341340, 7/14/1999, 5 ppmv at 3% O₂, dry) and (5) Air Products and Chemicals, Inc. (Application 337979, 6/16/1999, 5 ppmv at 3% O₂, dry).

The proposed NO_x emission limit for the Air Liquide Hydrogen Reformer is 5 ppmv at 3% O₂, dry. Since this is the lowest NO_x emission limit achieved in practice, no further energy, environmental, or economic impact assessment is needed.

5. Select BACT/ Document the Selection is BACT

Based on this review, NO_x BACT is proposed as SCR with combustion controls (low NO_x burners) at 5 ppmv at 3% O₂, dry, or 0.0058 lb/MMBtu.

4.2.2 PM₁₀ BACT – Hydrogen Plant Reformer Furnace

1. Identify All Available Control Technologies

The available technologies are the same as listed in Table 5 of Section 4.1.2.

2. Eliminate Technically Infeasible Options

All options in Table 5 are technically feasible.

3. Rank Remaining Technologies

See next (Step 4) discussion.

4. Evaluate Remaining Technologies

While the listed control technologies are all technically feasible, only good combustion practice is used for controlling PM₁₀ emissions from gas-fired heaters, as described in Section 4.1.2.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted for currently achieved control levels. No applicable PM₁₀ BACT emission levels were found. The five SCAQMD BACT Determinations for hydrogen reformer furnaces did not include PM₁₀, thus, from Section 4.1.2, a PM₁₀ emission limit of 0.0075 lb/MMBtu is representative of good combustion practice with gas-fired process heaters. In this case, the proposed Hydrogen Reformer will fire up to 85 percent PSA off gas, which produces less PM₁₀ emissions due to high hydrogen content. It is proposed that with the inclusion of PSA off gas, a reasonable PM₁₀ emission limit would be half the amount produced by natural gas alone, or 0.0037 lb/MMBtu.

5. Select BACT/ Document the Selection is BACT

Based on this review, PM₁₀ BACT is proposed as good combustion practice at 0.0037 lb/MMBtu. The proposed PM₁₀ emissions level is consistent with the lowest level achieved in practice, with further consideration given for the PSA off gas in the fuel mixture.

4.3 SULFUR RECOVERY UNIT (SRU)

The proposed new Unit 235 SRU will be a closed Claus process supported by an amine-based TGTU to convert unreacted hydrogen sulfide (H₂S) from the Claus process. The TGTU is also a closed process. Any unreacted H₂S in the tail gas passing through the TGTU will be oxidized in a new tail gas incinerator, which is the emission point for the process. Vents from the new sulfur loading rack will also be routed to the tail gas incinerator for oxidation of H₂S. Therefore, BACT for the SRU was assessed for NO_x and PM₁₀ from the tail gas incinerator.

4.3.1 NO_x BACT – SRU Tail Gas Incinerator

1. Identify All Available Control Technologies

The available technologies are the same as listed in Table 3 of Section 4.1.1.

2. Eliminate Technically Infeasible Options

The only option listed in Table 3 that is technically feasible for an SRU tail gas incinerator is combustion control with low-NO_x burners. The other technologies are either based on lowering flame temperature, which is not compatible with the primary function of the incinerator (i.e., efficient oxidation of reduced sulfur compounds), or add-on controls that have not been demonstrated technically feasible for a thermal oxidizer. There are significant technical differences between thermal oxidizers and the combustion sources for which these technologies have been demonstrated in practice.

3. Rank Remaining Technologies

The only technically feasible NO_x control technology is combustion control with low-NO_x burners.

4. Evaluate Remaining Technologies

Technically feasible technologies are reviewed on a case-by-case basis taking into consideration energy, environmental, and economic impacts beginning with the top option. If the top option is not selected as BACT, the next most effective control is evaluated until it cannot be ruled out for energy, environmental, or economic reasons.

In this case, a review of the USEPA RLBC and CARB BACT Clearinghouse was conducted for the most efficient low-NO_x burners achieved in practice for tail gas thermal oxidizers for SRU TGTUs. These reviews resulted in the lowest NO_x emission limit achieved in practice as 42.2 ppmv @ 7% O₂, dry, or 0.0667 lb/MMBtu, associated with the recently issued PSD permit for the SRU TGTU at the ConocoPhillips Ferndale Refinery. This level, for a unit currently in operation, is similar to the 0.06 lb/MMBtu level proposed by the ADEQ for the Arizona Clean Fuels Yuma LLC (ADEQ 2005), a facility not yet in operation.

5. Select BACT/ Document the Selection is BACT

Based on this review, NO_x BACT is proposed as combustion control with low-NO_x burners at 42.2 ppmv at 7% O₂, dry, or 0.0667 lb/MMBtu.

4.3.2 PM₁₀ BACT – SRU Tail Gas Incinerator

1. Identify All Available Control Technologies

The available technologies are the same as listed in Table 5 of Section 4.1.2.

2. Eliminate Technically Infeasible Options

All options in Table 5 are technically feasible.

3. Rank Remaining Technologies

See next (Step 4) discussion.

4. Evaluate Remaining Technologies

While the listed control technologies are all technically feasible, only good combustion practice is used for controlling PM₁₀ emissions from the combustion of gaseous fuels, as described in Section 4.1.2.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted for currently achieved control levels. No applicable PM₁₀ BACT emission levels were found. It is proposed that reasonable PM₁₀ emission limit would be the amount produced by natural gas alone, or 0.0075 lb/MMBtu.

5. Select BACT/ Document the Selection is BACT

Based on this review, PM₁₀ BACT is proposed as good combustion practice at 0.0075 lb/MMBtu. The proposed PM₁₀ emissions level is consistent with the lowest level achieved in practice.

4.4 New Flaring

The proposed project includes a new Hydrogen Plant flare that would operate during planned and unplanned events. The shutdown and startup of the new Unit 240/246 would also cause new flaring emissions from the existing Main Flare, but this is estimated to occur only once every three years.

Flares operate primarily as air pollution control devices, but are nonetheless emission sources subject to BACT analyses. The technically feasible control options for emissions of all pollutants from flares are equipment design specifications and work practices: minimizing exit velocity, ensuring adequate heat value of combusted gases, and minimizing the quantity of gases combusted. Each of these control options is technically feasible and is required for the operation of emergency flares at the refinery.

The equipment design criteria for emergency flares are based largely on the parallel requirements set forth in the NSPS regulations (40 CFR 60.18) and the National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations (40 CFR 63.11). These include a maximum allowable exit velocity, a requirement for smokeless operation, and a minimum allowable net heating value for gases combusted in the flares. ConocoPhillips is not aware of any more stringent requirements imposed on flares at any other petroleum refinery, nor any

PROPOSED-March 13, 2007

Evaluation Report, Application No. 13678, Air Liquide Large Industries US L.P., Facility B7459

other technically feasible control options for emissions of any pollutants from flares.