December 19, 2012

Ms. Melanie Magee
Air Permits Section (6PD-R)
Environmental Protection Agency
1445 Ross Avenue
Dallas, TX 75202

via Lone Star Overnight #Z9323407

Subject: **Permit Amendment Application**
TCEQ Permit No. 901
OCI Beaumont LLC
TCEQ Account No.: JE-0343-H
CN603806860 RN102559291

Dear Ms. Magee:

On behalf of OCI Beaumont LLC (OCI), Wolf Environmental LLC is submitting the enclosed permit amendment application for Permit 901 at the OCI site in Nederland Texas. The permit amendment requests the permanent authorization of the methanol unit primary reformers beyond the three years that is currently authorized effective December 2011 and to debottleneck the existing processes. The debottlenecking will increase the production capacity of the methanol units while improving the energy efficiency of the methanol process.

The project is triggering the requirements for Prevention of Significant Deterioration (PSD) for the following pollutants: VOC, CO, PM10, PM2.5, and greenhouse gases (GHG's). Since TCEQ is not the permitting authority for GHG's, separate applications have been prepared for TCEQ and the EPA. A copy of the TCEQ PSD permit application is enclosed for reference purposes.

RECEIVED
12 DEC 21 PM 4:14
AIR PERMITS SECTION
6PD-R

Wolf Environmental LLC – 281-482-4200 Fax / 281-482-4204
Mailing: P.O. Box 1483 – Friendswood, Texas 77549
Physical: 121 E Magnolia, Suite 204 – Friendswood, Texas 77546

OCI Beaumont LLC

Application for Prevention of Significant Deterioration Air Permit for Greenhouse Gases

Air Permit No. 901

TCEQ Account No. JE-0343-H
CN603806860 RN102559291

Prepared for:

OCI Beaumont LLC
PO Box 1647
Nederland, TX 77627

Prepared by:

Wolf Environmental
PO Box 1483
FRIENDSWOOD, TX. 77549

Shawn Haven
Project Manager

Submitted: December 19,2012

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1.0 IDENTIFYING AND ADMINISTRATIVE INFORMATION

OCI Beaumont LLC (OCI), located in Jefferson County, Texas, is submitting this permit amendment application in two parts. Both parts are Federal New Source Review Prevention of Significant Deterioration (PSD) applications. The traditional criteria pollutants portion of the amendment application is submitted to the TCEQ. The greenhouse gas (GHG) portion of the amendment is submitted to the EPA for review.

This is the EPA GHG permit application.

This application requests amendment of the existing site air permit to permanently authorize the methanol process unit primary reformers and debottleneck the methanol and ammonia processes. OCI is requesting the addition of new sources to increase production and improve energy efficiency in the plant. OCI was granted a permit on 12/21/2011 for construction of an ATR (autothermal reforming) process at this site. That project will not be completed; therefore OCI is requesting the voidance of that authorization in this permit application. This amendment application is based on the plant processes and equipment prior to that application. The ATR project is being replaced with this debottlenecking project. The ATR project did not trigger the GHG permitting rules. There was no GHG permitting action associated with the previous permit amendment. This amendment application does trigger the GHG permitting requirements.

OCI is requesting that EPA and TCEQ authorize the methanol reformers beyond the three years that is currently allowed in Permit 901. Selective catalytic reduction (SCR) is proposed as BACT for the combustion sources represented in this application. The reformers (existing) and pre-reformer fired heater (new source) will reduce nitrogen oxide emissions by applying SCR technology. We are also increasing the production capacity of the Methanol Plant and the Ammonia Plant. Ammonia unit production is being increased through minor changes in feedstock availability and process optimization. Methanol unit capacity is increased by the addition of a pre-reformer, pre-reformer fired heater and saturator column. The addition of this equipment allows significant energy efficiency improvement to the process. This project allows the recovery and recycle of two former waste water streams (Stripper Tails and Dehydrator Tails) and one atmospheric vent (CO2 Stripper Vent) through the saturator column for recovery of organics for feedstock and two atmospheric vent streams (DME Eductor and the Stripper Tails Tank Vent) that will be routed to the Methanol Unit Plant Flare for destruction. We are also adding a new flare to control MSS emissions from the reformer vent during emission events, startups, and shutdowns.

This section contains basic identifying information for the site and a summary of the potential GHG emissions for the sources addressed in this application. The following forms are included in this section:

- TCEQ Form PI-1(General Application for Air Preconstruction Permit and Amendments);
- TCEQ Table 30 (Estimated Capital Cost and Fee Verification); and
- Table 1(a) (Emissions Point Summary).

1.1 Form PI-1(General Application for Air Preconstruction Permit and Amendments)

Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

TCEQ

Important Note: The agency **requires** that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued *and* no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: OCI Beaumont LLC		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: Frank Bakker		
Title: General Manager		
Mailing Address: P.O. Box 1647		
City: Nederland	State: TX	ZIP Code: 77627
Telephone No.: (409) 723-1900	Fax No.:	E-mail Address: Frank.Bakker@ocibeaumont.com
C. Technical Contact Name: Dan Parrish		
Title: Environmental Advisor		
Company Name: OCI Beaumont LLC		
Mailing Address: P.O. Box 1647		
City: Nederland	State: TX	ZIP Code: 77627
Telephone No.: (281) 482-4200 x104	Fax No.: (281) 482-4204	E-mail Address: dparrish@wolf-env.com
D. Site Name: OCI Beaumont LLC		
E. Area Name/Type of Facility: OCI Beaumont LLC		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Methanol and Ammonia Manufacturing		
Principal Standard Industrial Classification Code (SIC): 2869		
Principal North American Industry Classification System (NAICS):		
G. Projected Start of Construction Date: Upon Permit Issuance		
Projected Start of Operation Date: 03/2014		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 5470 N Twin City Hwy		
City/Town: Nederland	County: Jefferson	ZIP Code: 77627
Latitude (nearest second): 30° 1' 3"	Longitude (nearest second): 94° 2' 2"	

Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility): JE-0343-H	
J. Core Data Form.	
Is the Core Data Form (Form 10400) attached? If *No*, provide customer reference number and regulated entity number (complete K and L).	☒ YES ☐ NO
K. Customer Reference Number (CN): 603806860	
L. Regulated Entity Number (RN): 102559291	
II. General Information	
A. Is confidential information submitted with this application? If *Yes*, mark each **confidential** page **confidential** in large red letters at the bottom of each page.	☐ YES ☒ NO
B. Is this application in response to an investigation or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ NO
C. Number of New Jobs: 15	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: Tommy Williams	District No.: 4
Representative: Joe D. Deshotel	District No.: 22
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested. Initial ☐ Amendment ☒ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation ☐	
B. Permit Number (if existing): NSR 901	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction ☒ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Prevention of Significant Deterioration ☒ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ Other:__________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

III. Type of Permit Action Requested (continued)		
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.		☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If *No*, attach detailed information.		☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?		☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.		
List: N/A		
G. Are you permitting planned maintenance, startup, and shutdown emissions? If *Yes*, attach information on any changes to emissions under this application as specified in VII and VIII.		☒ YES ☐ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)		
Is this facility located at a site required to obtain a federal operating permit? If *Yes*, list all associated permit number(s), attach pages as needed).		☒ YES ☐ NO ☐ To be determined
Associated Permit No (s.): O1645		
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved. FOP Significant Revision ☐ FOP Minor ☒ Application for an FOP Revision ☐ To Be Determined ☐ Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☐ None ☐		

III. Type of Permit Action Requested (continued)	
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. (check all that apply)	
GOP Issued ☐ GOP application/revision application submitted or under APD review ☐	
SOP Issued ☐ SOP application/revision application submitted or under APD review ☒	
IV. Public Notice Applicability	
A. Is this a new permit application or a change of location application?	☐ YES ☒ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☒ YES ☐ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO
If *Yes*, list the affected state(s) and/or Class I Area(s).	
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.	
1. Is there any change in character of emissions in this application?	☒ YES ☐ NO
2. Is there a new air contaminant in this application?	☐ YES ☒ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☒ NO
F. List the total annual emission increases associated with the application (*list* **all** *that apply and attach additional sheets as needed*): **(tpy)**	
Volatile Organic Compounds (VOC): 96.94	
Sulfur Dioxide (SO_2): 0.29	
Carbon Monoxide (CO): 86.39	
Nitrogen Oxides (NO_x): -470.43	
Particulate Matter (PM): 77.36	
PM $_{10}$ microns or less (PM_{10}): 77.36	
PM $_{2.5}$ microns or less ($PM_{2.5}$): 77.36	
Lead (Pb): N/A	
Hazardous Air Pollutants (HAPs): N/A	
Other speciated air contaminants **not** listed above: Ammonia: 53.74; CO_2: 1460,888.2; CH_4: 252.0; N_2O: 14.7; CO_{2e}: 1,470,750.6	

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

V. Public Notice Information (complete if applicable)			
A. Public Notice Contact Name: Brian Lucas			
Title: HSE Manager			
Mailing Address: P.O. Box 1647			
City: Nederland	State: Texas	ZIP Code: 77627	
Telephone No.: (409) 723-1900			
B. Name of the Public Place: Marion & Ed Hughes Public Library			
Physical Address (No P.O. Boxes): 2712 Nederland Ave.			
City: Nederland	County: Jefferson	ZIP Code: 77627	
The public place has granted authorization to place the application for public viewing and copying.			☒ YES ☐ NO
The public place has internet access available for the public.			☒ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits			
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.			
The Honorable: Jeff Branick			
Mailing Address: 1149 Pearl			
City: Beaumont	State: Texas	ZIP Code: 77701	
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? *(For Concrete Batch Plants)*			☐ YES ☐ NO
Presiding Officers Name(s):			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
3. Provide the name, mailing address of the chief executive of the city for the location where the facility is or will be located.			
Chief Executive: Mayor R.A. "Dick" Nugent			
Mailing Address: P.O. Box 967			
City: Nederland	State: TX	ZIP Code: 77627	

V. Public Notice Information (complete if applicable) (continued)			
3. Provide the name, mailing address of the Indian Governing Body for the location where the facility is or will be located. *(continued)*			
Name of the Indian Governing Body:			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
D. Bilingual Notice			
Is a bilingual program **required** by the Texas Education Code in the School District?			☐ YES ☒ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?			☐ YES ☒ NO
If *Yes*, list which languages are required by the bilingual program?			
VI. Small Business Classification (Required)			
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?			☐ YES ☒ NO
B. Is the site a major stationary source for federal air quality permitting?			☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?			☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?			☒ YES ☐ NO
VII. Technical Information			
A. The following information must be submitted with your Form PI-1 (this is just a checklist to make sure you have included everything)			
1. Current Area Map ☒			
2. Plot Plan ☒			
3. Existing Authorizations ☒			
4. Process Flow Diagram ☒			
5. Process Description ☒			
6. Maximum Emissions Data and Calculations ☒			
7. Air Permit Application Tables ☒			
a. Table 1(a) (Form 10153) entitled, Emission Point Summary ☒			
b. Table 2 (Form 10155) entitled, Material Balance ☒			
c. Other equipment, process or control device tables ☒			

VII. Technical Information			
B. Are any schools located within 3,000 feet of this facility?			☐ YES ☒ NO
C. Maximum Operating Schedule:			
Hours: 24	Day(s): 7	Week(s): 52	Year(s):
Seasonal Operation? If Yes, please describe in the space provide below.			☐ YES ☒ NO
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☒ YES ☐ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.			
MSS emissions have been previously permitted. MSS activities associated with this project are included in the application.			
E. Does this application involve any air contaminants for which a *disaster review* is required?			☐ YES ☒ NO
F. Does this application include a pollutant of concern on the *Air Pollutant Watch List (APWL)*?			☐ YES ☒ NO

VIII. State Regulatory Requirements **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*	
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?	☒ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?	☒ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?	☒ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?	☒ YES ☐ NO

IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?	☐ YES ☒ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	☐ YES ☒ NO
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** ***The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.***	
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
	Is the estimated capital cost of the project greater than $2 million dollars?	☒ YES ☐ NO
	If *Yes*, submit the application under the seal of a Texas licensed P.E.	
XI.	**Permit Fee Information**	
	Check, Money Order, Transaction Number ,ePay Voucher Number:	Fee Amount: $75,000
	Company name on check: OCI Beaumont	Paid online?: ☐ YES ☒ NO
	Is a copy of the check or money order attached to the original submittal of this application?	☒ YES ☐ NO ☐ N/A
	Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☒ YES ☐ NO ☐ N/A

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

TCEQ

XII. Delinquent Fees and Penalties

This form **will not be processed** until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.

XIII. Signature

The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.

Name: Frank Bakker

Signature: ____________________
Original Signature Required

Date: 12/19/12

1.2 TCEQ Table 30 (Estimated Capital Cost and Fee Verification)

Texas Commission on Environmental Quality
Table 30
Estimated Capital Cost and Fee Verification

Include estimated cost of the equipment and services that would normally be capitalized according to standard and generally accepted corporate financing and accounting procedures. Tables, checklists, and guidance documents pertaining to air quality permits are available from the Texas Commission on Environmental Quality, Air Permits Division Web site at **www.tceq.state.tx.us/nav/permits/air_permits.html**.

I. DIRECT COSTS [30 TAC § 116.141(c)(1)]	**Estimated Capital Cost**
A. A process and control equipment not previously owned by the applicant and not currently authorized under this chapter	$0
B. Auxiliary equipment, including exhaust hoods, ducting, fans, pumps, piping, conveyors, stacks, storage tanks, waste disposal facilities, and air pollution control equipment specifically needed to meet permit and regulation requirements	$0
C. Freight charges	$0
D. Site preparation, including demolition, construction of fences, outdoor lighting, road and parking areas	$0
E. Installation, including foundations, erection of supporting structures, enclosures or weather protection, insulation and painting, utilities and connections, process integration, and process control equipment	$0
F. Auxiliary buildings, including materials storage, employee facilities, and changes to existing structures	$0
G. Ambient air monitoring network	$0
II. INDIRECT COSTS [30 TAC § 116.141(c)(2)]	**Estimated Capital Cost**
A. Final engineering design and supervision, and administrative overhead	$0
B. Construction expense, including construction liaison, securing local building permits, insurance, temporary construction facilities, and construction clean-up	$0
C. Contractor's fee and overhead	$0
TOTAL ESTIMATED CAPITAL COST	$ ~ 83,000,000

I certify that the total estimated capital cost of the project as defined in 30 TAC § 116.141 is equal to or less than the above figure. I further state that I have read and understand Texas Water Code § 7.179, which defines CRIMINAL OFFENSES for certain violations, including intentionally or knowingly making, or causing to be made, false material statements or representations.

Company Name: OCI Beaumont LLC

Company Representative Name (please print): Frank Bakker Title: Plant Manager

Company Representative Signature: [signature]

Estimated Capital Cost		**Permit Application Fee**	**PSD/Nonattainment Application Fee**
Less than	**$300,000**	**$900 (minimum fee)**	**$3,000 (minimum fee)**
$300,000 to	**$25,000,000**	**0.30% of capital cost**	
$300,000 to	**$7,500,000**		**1.0% of capital cost**
Greater than	**$25,000,000**	**$75,000 (maximum fee)**	
Greater than	**$7,500,000**		**$75,000 (maximum fee)**

PERMIT APPLICATION FEE (from table above) = $ 75,000.00 Date: 12/13/12

1.3 Table 1(a) (Emissions Point Summary)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: December 2012	**Permit No.: 901**	**Regulated Entity No.: 102559291**
Area Name: OCI Beaumont LLC		**Customer Reference No.: 603806860**

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
Emission Point			**Component or Air Contaminant Name**	**Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) Name**		**(A) Pound Per Hour**	**(B) TPY**
STK41	RFM41	Reforming Furnaces	CO_2		1,260,266.93
			CH_4		62.56
			N_2O		12.51
			CO_2e		1,265,460
PRFMHTR	PRFMHTR	Pre-Reformer Fired Heater	CO_2		164,232.47
			CH_4		9.32
			N_2O		1.86
			CO_2e		165,006
MET-STK44	MET-STK44	Carbon Dioxide Stripper Vent	CO_2		17.30
			CH_4		0.20
			N_2O		0.00
			CO_2e		22

326	MVCSFLR	Marine Vapor Control System Flare	CO_2		6,666.12
			CH_4		46.61
			N_2O		0.07
			CO_2e		7,666
FL321	AMMFLARE	Ammonia Plant Flare	CO_2		7,074.09
			CH_4		51.27
			N_2O		0.07
			CO_2e		8,173
45	FLARE	Methanol Plant Flare	CO_2		10,994.59
			CH_4		68.48
			N_2O		0.11
			CO_2e		12,467
FL42	FL42	Reformer MSS Flare	CO_2		11,636.73
			CH_4		13.60
			N_2O		0.12
			CO_2e		11,943

EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: December 2012	Permit No.: 901	Regulated Entity No.: 102559291
Area Name: OCI Beaumont LLC		Customer Reference No.: 603806860

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS							
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building Height (Ft.)	6. Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) NAME	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
STK-41	RFM41	Reforming Furnaces	15	TBD	TBD	50	TBD	TBD	TBD	TBD			
PRFMHTR	PRFMHTR	Pre-Reformer Fired Heater	15	TBD	TBD		TBD	TBD	TBD	TBD			
MET-STK44	MET-STK44	Carbon Dioxide Stripper Vent	15	400197	3320915	85		0.83	69.3	267			
326	MVCSFLR	Marine Vapor Control System Flare	15	400861	3321468	125		0.83	12	~1800			
FL321	AMMFLARE	Ammonia Unit Flare	15	400280	3320876		200	3.5	108.3	~1800			
45	FLARE	Methanol Plant Flare	15	400297	3320970	217		2	200	~1800			
FL42	FL42	Reformer MSS Flare	15	TBD	TBD		152	3.5	116	~1800			

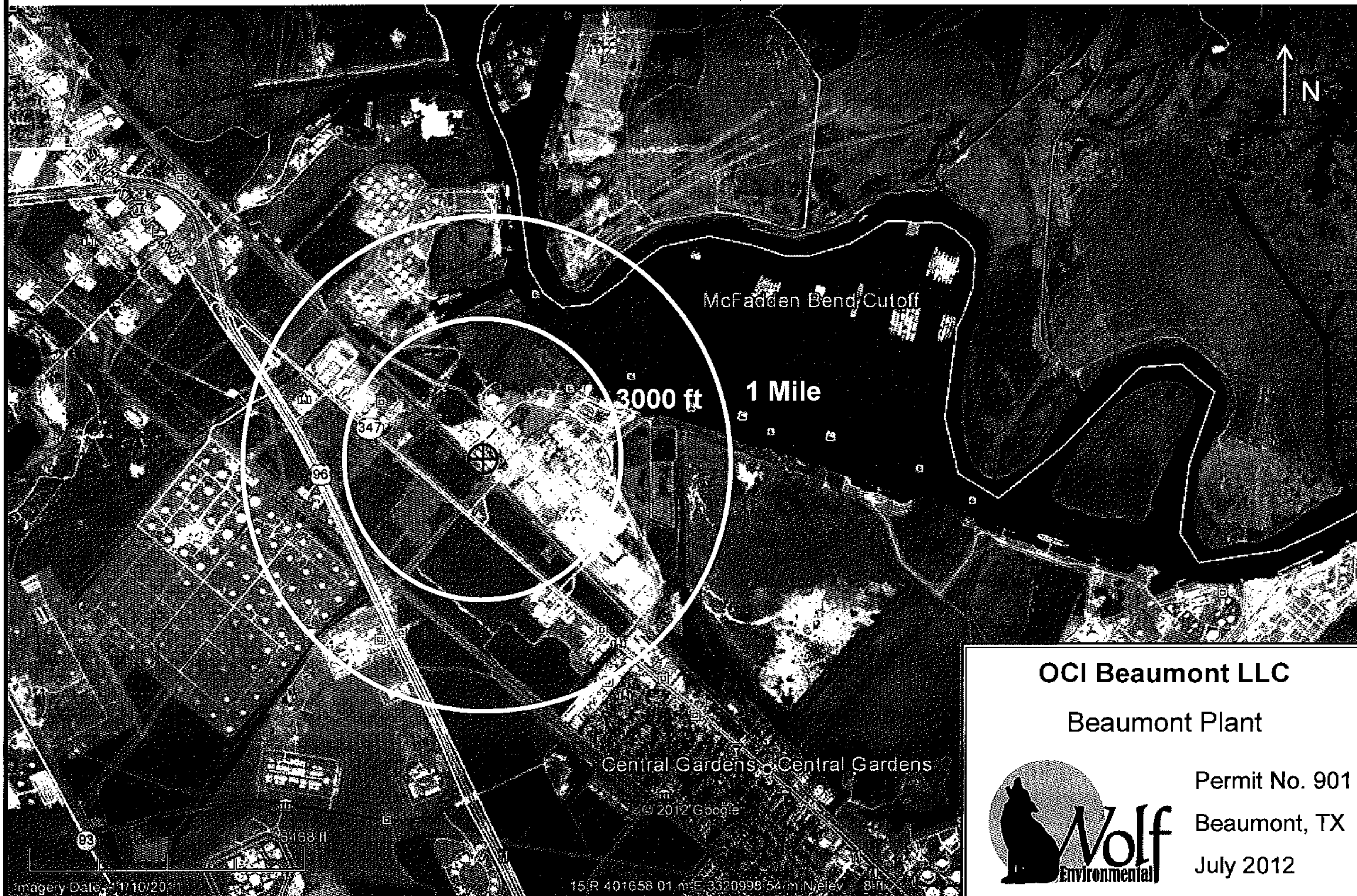
EPN = Emission Point Number
FIN = Facility Identification Number

2.0 MAPS AND PLOT PLANS

An area map and plot plan for the site is included in the following pages. The area map shows the location of the property relative to surrounding roads, residences, a plant benchmark, a true north arrow, property lines, and other geographic features. The plot plan shows the location of the equipment contained on the site.

OCI Beaumont LLC
Site Area Map

⊕ 30° 0' 55.84" N
94° 2' 5.79" W



OCI Beaumont LLC

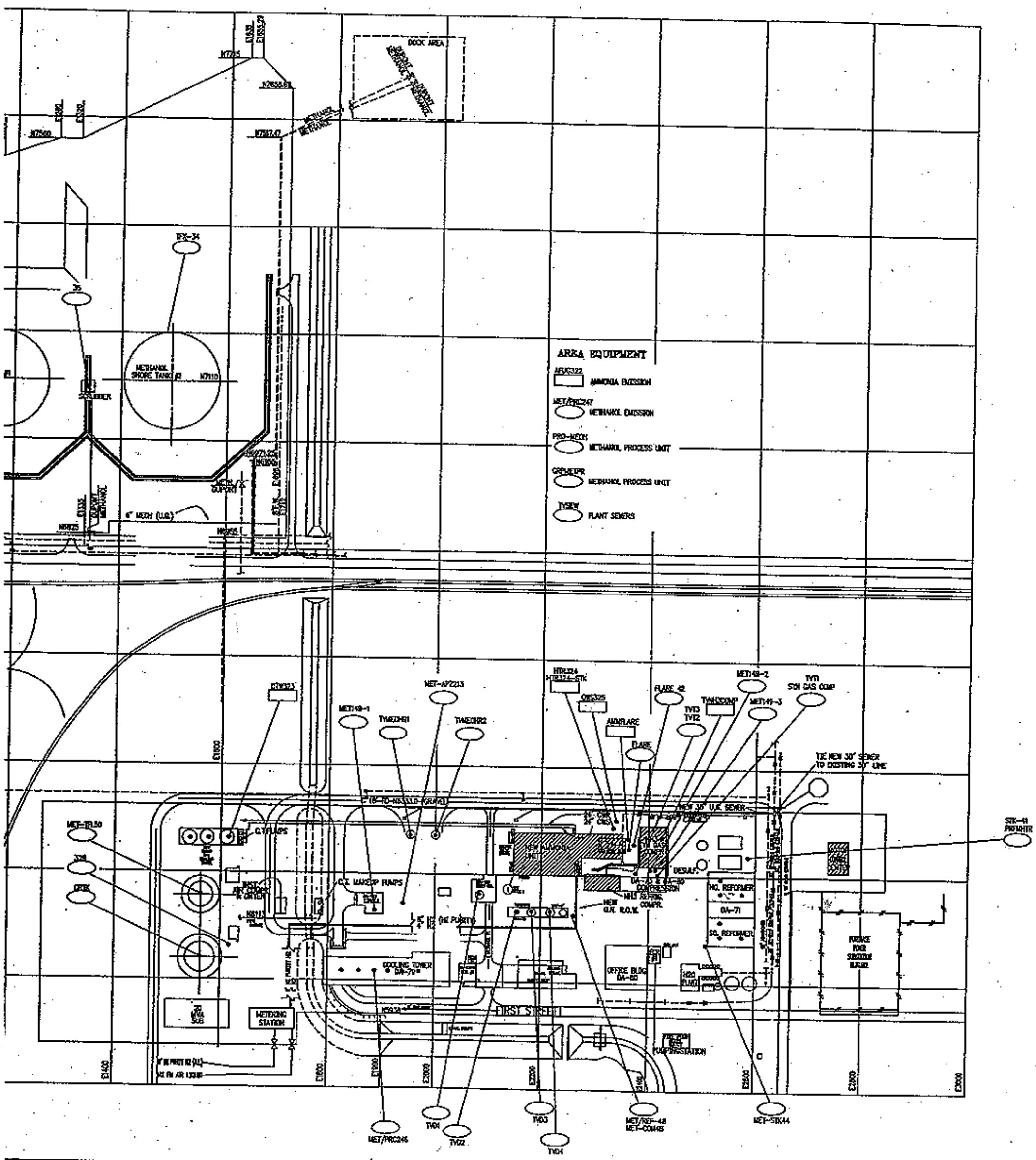
Beaumont Plant

Wolf Environmental

Permit No. 901

Beaumont, TX

July 2012



NOTES

AMMONIA EMISSION

METHANOL EMISSION

1. UTM COORDINATE
   N 3320804.1
   E 400241.1

   PLANT COORDINATE
   N 6200
   E 2149

REFERENCE DRAWINGS

NO.	REVISIONS	DATE	BY	CH'D.	APP'D.
1	PSD APP	12/05/12	CP	DP	DP

EST. NO. JOB NO.

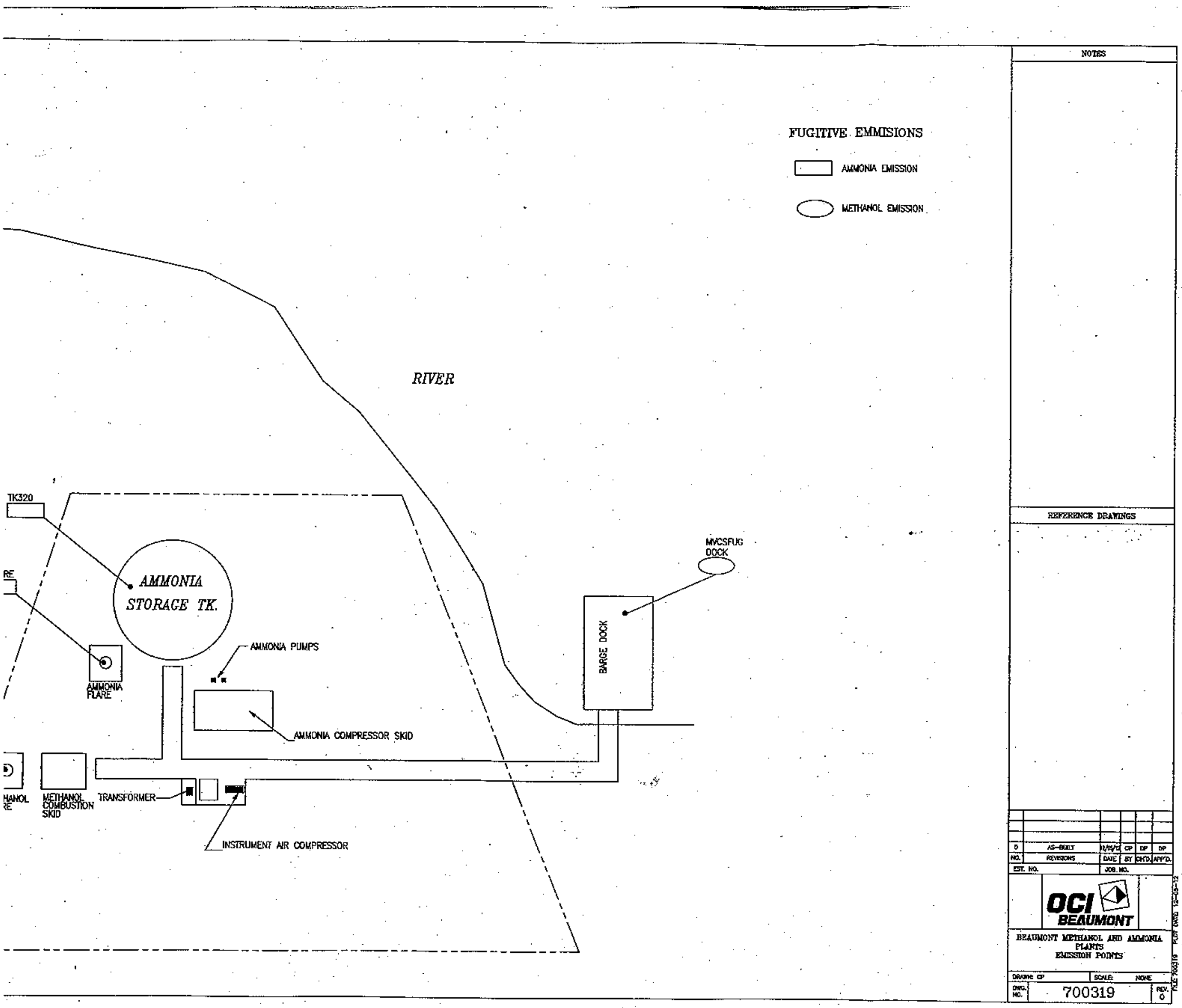
OCI BEAUMONT

**BEAUMONT METHANOL AND AMMONIA PLANTS
EMISSION POINTS**

DRAWN: K. WALDRUP SCALE: 1"=100'

DWG. NO. 700318 REV. 1

FILE 700318 PLOT DATE: 12-05-12


FUGITIVE EMMISIONS
AMMONIA EMISSION
METHANOL EMISSION
RIVER
TK320
AMMONIA STORAGE TK.
AMMONIA FLARE
AMMONIA PUMPS
AMMONIA COMPRESSOR SKID
METHANOL COMBUSTION SKID
TRANSFORMER
INSTRUMENT AIR COMPRESSOR
MVCSFUG DOCK
BARGE DOCK
NOTES
REFERENCE DRAWINGS
0 AS-BUILT CP DP DP
NO. REVISIONS DATE BY CH'D. APP'D.
EST. NO. JOB. NO.
OCI BEAUMONT
BEAUMONT METHANOL AND AMMONIA PLANTS
EMISSION POINTS
DRAWN: CP SCALE: NONE
DWG. NO. 700319 REV. 0
FILE 700319 PLOT DATE 12-05-12

3.0 PROCESS DESCRIPTION

OCI operates the methanol and ammonia production units located within the DuPont Beaumont Works Site (DBW) in Nederland, Texas. Multiple tenants operate process units within the DBW site, including OCI, E. I. du Pont de Nemours, and Lucite International, Inc. (Lucite), with Lucite being the operator of the DBW site services (steam, wastewater treatment, etc.) The methanol and ammonia units can be operated independently of each other or together. Methanol production can be increased by the addition of carbon dioxide. This results in four basic operating scenarios for the plant that is described in greater detail later in the process description. The methanol unit is regulated under 40 CFR 63 Subparts F, G and H (SOCMI HON). The marine loading dock is regulated under 40 CFR 63 Subpart Y (Marine MACT). These MACT standards dictate the control strategies for the plant processes and equipment. Although OCI complies with these MACT standards, Lucite operates the loading dock and the wastewater treatment system that treats a SOCMI HON Group 1 wastewater stream generated in the methanol production process. The ammonia production process is not applicable to any state or federal regulations other than the construction permit. The OCI processes are described in greater detail as follows:

3.1 Methanol Reforming Process

The methanol manufacturing process begins with natural gas. Traces of sulfur must be removed to avoid poisoning the reformer and synthesis catalyst later in the process. The natural gas is passed through a catalyst bed to desulfurize the natural gas. The desulfurizer catalyst requires no onsite regeneration. The desulfurized natural gas is then mixed with steam and the mixture is passed through the pre-reformer catalyst bed. The pre-reformer begins the formation of process gas and converts any hydrocarbons heavier than methane into methane. A supplemental fired heater is used to heat the gases. This pre-reformer heater utilizes selective catalytic reduction (SCR) to control NOx emissions. The partially converted process gas is then sent to the primary reformer to complete the conversion of feedstock to process gas. This combination of pre-reforming and reforming technology improves product yields and increases the energy efficiency of the process. The reaction of natural gas (principally methane) with steam forms hydrogen (H_2), carbon monoxide (CO), and carbon dioxide (CO_2). The reaction requires heat that is provided by burning fuel gas in the reformer furnace which is composed of natural gas, high pressure purge gas from the methanol reactor circulation loop and several other small purge gas streams either directly from the units or from the ammonia plant pressure swing adsorption (PSA) process. The heat generated in the reformers is used to preheat the natural gas, preheat the process steam, and produce steam for use in the plant. Emissions from fuel combustion are emitted through the reformer stacks. The combustion emissions are routed to the SCR units to control the emission of nitrogen oxides from the primary reformers.

The process (or synthesis) gas leaving the reformers is then cooled and can be combined with by-product carbon dioxide from the crude methanol tank and other potential CO_2 sources such as pipeline delivery from offsite. The combined gases are cooled, compressed in the synthesis gas compressor to 1100 to 1550 psig and sent to the synthesis section as make-up gas. The synthesis gas leaving the reformer can also be sent directly to the synthesis section without adding by-product carbon dioxide. The process condensate produced in the cooling processes are collected and recovered as steam in the saturator column. The saturator column uses natural gas to strip unwanted process hydrocarbons from water streams. The saturated natural gas is used as feedstock for the process while the column recovers water as steam. This decreases the demand for reformer generated steam to meet the steam to carbon ratio requirements for the reformer operation.

The boiler feed water is normally moved by turbines and/or electric pumps. A standby diesel pump is available for emergencies. Abnormal operations include start-up/shutdown procedures, emergency/upset conditions, and maintenance procedures.

3.2 Methanol Synthesis Process

The synthesis of methanol occurs in two vessels, called methanol reactors, in the presence of a catalyst. The synthesis gas is a mixture of recycle gas from the methanol reactor circulation loop and fresh makeup gas from the reformers. The gas is circulated through the reactors with a recirculating compressor. On each pass, a portion of the carbon monoxide, hydrogen, and carbon dioxide is converted into methanol and water (crude methanol). The mixture leaving the reactors (methanol, water and unreacted gases) is cooled to separate the condensable liquid from the non-condensable gases using a water cooled heat exchanger. The separated unreacted gases are mixed with fresh makeup gas and recycled back to the reactors. Condensed crude methanol is stored in the crude storage tank prior to refining. A packed tower wet scrubber (crude tank scrubber) is used to recover methanol vapors from the crude storage tank off gas. The process can be operated in two modes after the methanol has been scrubbed from the off gas. In one mode, the scrubbed crude tank off gas can be routed to the CO_2 compressor 1st stage suction as supplemental carbon dioxide, only if the CO_2 compressor is in operation. In the other mode, the scrubbed crude tank off gas can be vented to the atmosphere through the vent at the outlet of the crude tank scrubber.

Crude methanol is purified in a four column refining (distillation) process to remove water and other impurities. Light end gases from the distillation process are sent through the condenser where the non-condensable gases are removed from the stream with a natural gas eductor and routed to the reformer fuel gas system. Undesired mixed alcohol streams from the distillation process are collected and recycled as feedstock through a saturator column. Natural gas feedstock strips the alcohols from the refining section in the saturator column and is sent to the pre-reformer as feedstock to improve the overall energy efficiency of the process. Purified methanol is then stored in two 7.5 million gallon methanol storage tanks prior to shipment. The methanol product storage tanks vent to a water scrubber system (the shore tank scrubber). The shore tank scrubber controls shore tank venting. The liquid effluent from the shore tank scrubber can be sent either to the Crude Tank Scrubber as a supplemental scrubber water supply or directly to the crude tank for recovery of the methanol.

OCI loads part of the methanol at a marine vessel loading dock equipped with a marine vapor control system and flare. Methanol can also be unloaded at the Lucite docks for storage in the methanol storage tanks should market conditions require this. Off-spec product is stored in an in-process internal floating roof storage tank prior to re-processing. Methanol is also sold to nearby customers via pipelines.

To control the buildup of excess hydrogen and undesirable gases (methane and nitrogen) in the synthesis loop, a portion of the unreacted high-pressure gas is continually purged from the system. When the ammonia plant is not operating, the purge gas is routed to the reformer fuel gas system and burned as supplementary fuel gas. When the ammonia plant is in operation this stream goes to the PSA unit. During start-up or shutdown of the methanol reaction area or under upset conditions, the process purge gas vents to the methanol flare.

Water is used as the cooling medium in several shell and tube heat exchangers throughout the plant. A seven-cell, induced draft Marley cooling tower removes the heat in the return water. The oil/water separator is used to aid in the recovery of lube oil, which the facility recycles, from the process rotating equipment. The oil/water separator is closed and vents through a carbon canister (adsorption) system. The oil/water separator also acts as an emergency spill control vessel. Methanol is not found in this process water unless equipment failure has occurred.

3.3 Methanol and Ammonia Plant Interaction

When the ammonia plant is operating, high-pressure purge gas from the methanol synthesis loop is routed from the reaction area to the ammonia process. The gas is first water washed in a scrubber column to remove trace amounts of methanol. The recovered methanol/water stream is routed to the crude methanol storage area for recovery as methanol product. The purge gas is then sent to a PSA unit to separate the hydrogen from the methane, carbon monoxide, carbon dioxide, and residual methanol. The pure hydrogen stream is now suitable for use in ammonia synthesis. The remaining purge stream of hydrogen, carbon monoxide, carbon dioxide and methane is sent to the reformers as supplementary fuel gas. The Btu value of the hydrogen removed from the purge stream is replaced with an equivalent Btu value of natural gas to maintain constant heat input in the reformers.

The crude tank scrubber is used to recover methanol vapors from the crude storage tank off gas. The crude tank scrubber uses recirculating wash water and fresh water to control emissions while recovering product. The liquid effluent from the crude tank scrubber is sent to the crude tank to be reprocessed in refining. After the off gas (primarily CO_2) is scrubbed to remove methanol, it is either routed to the CO_2 compressor for use in the synthesis of methanol, or vented to the atmosphere. Methanol recovered by the scrubber is routed to the crude methanol storage tank. The scrubber system is designed to scrub and recover the crude tank vapors continuously during normal operations.

3.4 Ammonia Plant

The ammonia plant produces liquid anhydrous ammonia from hydrogen and nitrogen. Hydrogen can be used from the methanol unit purge gas streams or imported via pipeline from local suppliers and joins with a nitrogen stream supplied by local suppliers via pipeline after the PSA Unit. This mixture, which is controlled to yield a 3:1 hydrogen to nitrogen molar ratio, is referred to as ammonia synthesis gas.

The ammonia synthesis gas passes to the make-up gas compressor where it is compressed and mixed with recycle gas from the ammonia synthesis loop. A mixture of fresh synthesis gas and recycle gas is preheated and constantly circulated through the ammonia converter. On each pass through the ammonia converter, a portion of the hydrogen and nitrogen react over beds of an iron oxide catalyst to form ammonia. This equilibrium reaction, which is sensitive to changes in temperature and pressure, allows only approximately 20% conversion of hydrogen and nitrogen to ammonia per pass through the converter. The optimum temperature in the ammonia converter is maintained by internal heat exchangers between the conversion beds.

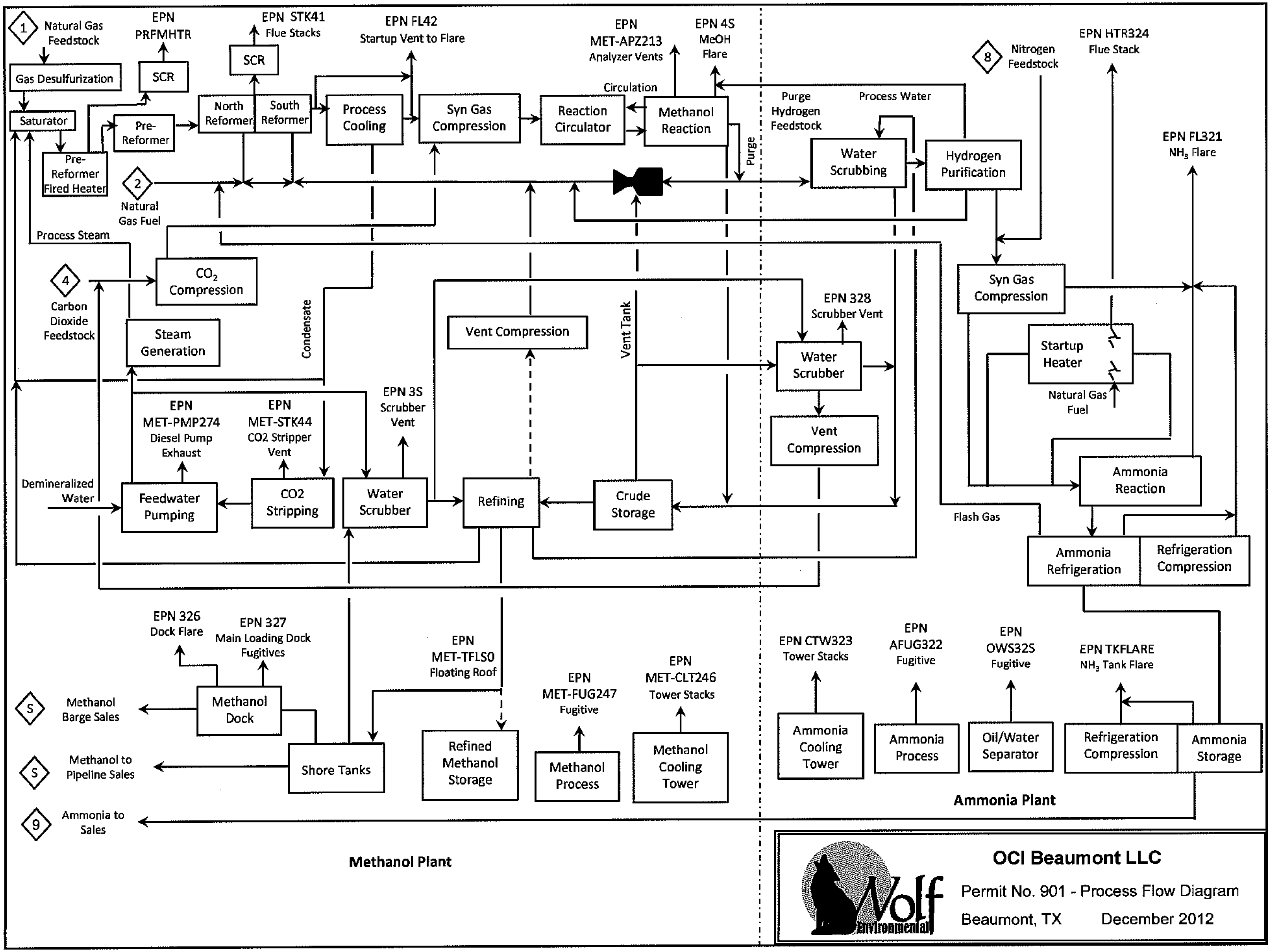
The converter effluent, a mixture of vaporous ammonia and unreacted hydrogen and nitrogen, passes through heat recovery exchangers, condensers, ammonia refrigeration chillers, and separators to remove the liquid ammonia from the synthesis gas. The liquid ammonia is depressurized into a letdown vessel and sent to the refrigeration system for further cooling.

The refrigeration section of the ammonia process is a closed loop system with an electric-driven refrigeration compressor. The system includes a series of condensers, accumulators, chillers, and separators. Liquid ammonia from the refrigeration system can be pumped via pipeline and valving to either OCI or Lucite NH3 storage tanks. Both of these tanks have 20,000 short ton capacities and have compressors for refrigerating purposes. No rail, truck or marine vessels are loaded at the OCI ammonia facility. OCI does however toll ammonia through their tank. This tolled ammonia can be unloaded at the Lucite docks. Loading of ammonia is contracted through Lucite.

A low-pressure purge gas stream is taken from the flash gas in the refrigeration section to remove non-condensable gases (primarily hydrogen). After passing through a refrigerated condenser, the low-pressure purge gas is burned in the reformer as fuel gas or flared. Two flares are used for MSS and normal operation. One flare is located in the ammonia plant, and the other flare is located next to the 20,000-ton storage tank. The flares are equipped with continuous pilots fueled by natural gas. The primary purpose of the flares is to combust ammonia vapors vented from pressure safety relief valves, drums, heat exchangers, compressors, pump casings and storage tanks during abnormal plant operations and MSS. It should be noted that non-ammonia process safety valves and start-up/shutdown vents are routed to the existing methanol plant flare.

3.5 Process Flow Diagrams

Process flow diagrams for the site processes are provided on the following pages.



1 Natural Gas Feedstock
Gas Desulfurization
Saturator
Pre-Reformer Fired Heater
EPN PRFMHTR
SCR
Pre-Reformer
North Reformer
South Reformer
EPN STK41 Flue Stacks
SCR
Process Cooling
EPN FL42 Startup Vent to Flare
Syn Gas Compression
Reaction Circulator
Circulation
EPN MET-APZ213 Analyzer Vents
Methanol Reaction
EPN 4S MeOH Flare
Purge
2 Natural Gas Fuel
Process Steam
4 Carbon Dioxide Feedstock
CO_2 Compression
Steam Generation
Condensate
Vent Compression
Vent Tank
Demineralized Water
Feedwater Pumping
EPN MET-PMP274 Diesel Pump Exhaust
CO2 Stripping
EPN MET-STK44 CO2 Stripper Vent
Water Scrubber
EPN 3S Scrubber Vent
Refining
Crude Storage
Purge Hydrogen Feedstock
Process Water
Water Scrubbing
Hydrogen Purification
8 Nitrogen Feedstock
EPN HTR324 Flue Stack
EPN FL321 NH_3 Flare
Syn Gas Compression
Startup Heater
Natural Gas Fuel
EPN 328 Scrubber Vent
Water Scrubber
Vent Compression
Ammonia Reaction
Flash Gas
Ammonia Refrigeration
Refrigeration Compression
EPN 326 Dock Flare
EPN 327 Main Loading Dock Fugitives
Methanol Dock
S Methanol Barge Sales
S Methanol to Pipeline Sales
9 Ammonia to Sales
Shore Tanks
EPN MET-TFLS0 Floating Roof
Refined Methanol Storage
EPN MET-FUG247 Fugitive
Methanol Process
EPN MET-CLT246 Tower Stacks
Methanol Cooling Tower
EPN CTW323 Tower Stacks
Ammonia Cooling Tower
EPN AFUG322 Fugitive
Ammonia Process
EPN OWS32S Fugitive
Oil/Water Separator
EPN TKFLARE NH_3 Tank Flare
Refrigeration Compression
Ammonia Storage
Ammonia Plant
Methanol Plant
Wolf Environmental
OCI Beaumont LLC
Permit No. 901 - Process Flow Diagram
Beaumont, TX December 2012

3.6 TCEQ Table 2 – Material Balance

TABLE 2

MATERIAL BALANCE

This material balance table is used to quantify possible emissions of air contaminants and special emphasis should be placed on potential air contaminants, for example: If feed contains sulfur,show distribution to all products. Please relate each material (or group of materials) listed to its respective location in the process flow diagram by assigning point numbers (taken from the flow diagram) to each material.

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate (lbs/hr or SCFM) standard conditions: 70°F 14.7 PSIA. Check appropriate column at right for each process.	Measurement	Estimation	Calculation
1. Raw Materials – Input					
Natural Gas	1	712,188 tons/yr			X
Hydrogen		165,253 tons/yr			X
Nitrogen	8	270,531 tons/yr			X
2. Fuels – Input					
Natural Gas and/or Purge Gas	2	21,981 MMscfyr			X
3. Products & By-Products – Output					
Methanol	5	1,098,000 metric tons/yr			X
Anhydrous Ammonia	9	332,727 metric tons/yr			X
4. Solid Wastes – Output					
No Routine Solid Wastes					
5. Liquid Wastes – Output					
Water (from demineralizer regeneration and cooling tower blowdown)	Unit	52.704 MM gal/yr			X
6. Airborne Waste (Solid) – Output					
Particulate Matter	See EPNs	See Table 1(a)			X
7. Airborne Wastes (Gaseous) – Output					
See Table 1(a)	See EPNs	See Table 1(a)			X

4.0 EMISSIONS CALCULATIONS AND METHODOLOGY

This section of the application contains a description of the emissions basis for each of the emission sources along with detailed emission calculations for each emission point that impacts greenhouse gas emissions as a result of the project. The following emission points that are addressed in this permit amendment application are as follows:

- North and South Reforming Furnaces (EPN: STK41);
- Pre-Reformer Fired Heater (EPNs: PRFMHTR);
- Reformer MSS Flare (EPN: FL42);
- Methanol Plant Flare (EPN: 45);
- Marine Vapor Control System Flare (EPN: 326);
- CO_2 Stripper Vent (EPN: MET-STK44);
- Ammonia Plant Flare (EPN: FL321)

Details related to each of the above mentioned emission points are discussed in subsequent subsections contained in this section of the permit application. The table on the following page summarizes the emission changes as a result of the project represented in this permit application.

4.1 Reforming Furnaces Maintenance (EPN: STK41)

The North and South steam reformers are the primary reformers for the Methanol Plant. The steam reformers have the ability to operate in four different operating modes as follows:

- Case A: Methanol plant stand-alone operation (without CO_2 addition)
- Case B: Methanol plant stand-alone operation (with CO_2 addition)
- Case C: Methanol and Ammonia plant production (without CO_2 addition)
- Case D: Methanol and Ammonia plant production (with CO_2 addition)

In order to determine the worst-case greenhouse gas emissions for each of the operating modes, emissions were calculated for each operating case and compared. The results of this analysis indicate that Case D will result in the worst-case GHG emissions; therefore, Case D will be used to establish the potential to emit allowable emissions for this source. Planned maintenance, startup, and shutdown (MSS) operations for the reformers are not expected to exceed the normal operation greenhouse gas mass emissions from any of the operating cases. There are no separate GHG MSS allowable mass emission limits needed for this source.

In order to calculate the baseline greenhouse gas emissions for determination of PSD applicability, calendar years 2003 and 2004 operational data was utilized. The baseline emissions are calculated based on combustion of gaseous fuel along with a liquid stream (stripper tails). With the addition of the saturator column to be constructed as part of this project, the stripper tails will no longer be combusted in the reformers. The stripper tails will be routed to the saturator column for recovery of organics for use as feedstock.

Emission Calculation Methodology (Gaseous Fuel)

$\underline{CO_2:}$

CO_2 emissions are calculated utilizing the following equation:

$$CO_2 = \frac{44}{12} \times Fuel \times CC \times \frac{MW}{MVC} \times 0.001$$ (Equation C-5, 40 CFR Part 98.33)

Where:
CO_2 = Carbon dioxide emissions in metric tons per year;
44/12 = Ratio of molecular weights of CO_2 to carbon;
Fuel = Annual volume of gaseous fuel combusted, scf;
CC = Carbon content of gaseous fuel combusted, Kg. C / Kg. fuel;
MW = Average molecular weight of gaseous fuel, Kg/Kg-mol;
MVC = Molar conversion factor, 849.5 scf/Kg-mol (@ 68 deg. F);
0.001 = Conversion factor from Kg to metric tons;

The carbon content of the gaseous fuel is calculated utilizing the following methodology:

$$CC = \sum(CF_i \times MF_i)/100$$

Where: CF_i = Carbon fraction of fuel species i;
MF_i = mole fraction of fuel species i;

The carbon fraction for each fuel species contained in the fuel is calculated utilizing the following methodology:

$$CF_i = C_i \div MW_i$$

Where: C_i = Carbon weight of fuel species i;
MW_i = Molecular weight of fuel species i;

The average molecular weight of the gaseous fuel is calculated utilizing the following methodology:

$$MW = \sum(MW_i \times MF_i)$$

Where: MW_i = Molecular weight of fuel species i;
MF_i = mole fraction of fuel species i;

<u>CH_4:</u>

CH_4 emissions are calculated utilizing the following equation:

$CH_4 = 0.001 \times EF_{CH4} \times Fuel$ (Equation C-8b, 40 CFR Part 98.33)

Where: EF_{CH4} = Emission Factor for CH_4 (from Table C-2, 40 CFR Part 98, Subpart C, 0.003 Kg/MMBtu;
Fuel = Annual gaseous fuel use, MMBtu/yr;

$\underline{N_2O}$:

N_2O emissions are calculated utilizing the following equation:

$N_2O = 0.001 \times EF_{N2O} \times Fuel$ (Equation C-8b, 40 CFR Part 98.33)

Where: EF_{CH4} = Emission Factor for CH_4 (from Table C-2, 40 CFR Part 98, Subpart C, 0.0006 Kg/MMBtu;
Fuel = Annual gaseous fuel use, MMBtu/yr;

Emission Calculation Methodology (Liquid Fuel – Stripper Tails)

Note: Liquid fuel calculation only applies to the baseline case. The stripper tails will not be combusted in the reformers post-project.

$\underline{CO_2}$:

CO_2 emissions are calculated utilizing the following equation:

$CO_2 = \frac{44}{12} \times Fuel \times CC \times 0.001$ (Equation C-4, 40 CFR Part 98.33)

Where: CO_2 = Carbon dioxide emissions in metric tons per year;
44/12 = Ratio of molecular weights of CO_2 to carbon;
Fuel = Annual volume of liquid fuel combusted, gallons;
CC = Carbon content of liquid fuel combusted, Kg. C / gallon fuel;
0.001 = Conversion factor from Kg to metric tons;

The carbon content of the liquid fuel is calculated utilizing the following methodology:

$CC = \sum(CF_i \times MF_i)/100$

Where: CF_i = Carbon fraction of species i;
MF_i = mole fraction of species i;

The carbon fraction for each species contained in the liquid fuel is calculated utilizing the following methodology:

$$CF_i = C_i \div MW_i$$

Where: C_i = Carbon weight of fuel species i;
MW_i = Molecular weight of fuel species i;

The average molecular weight of the liquid fuel is calculated utilizing the following methodology:

$$MW = \sum(MW_i \times MF_i)$$

Where: MW_i = Molecular weight of fuel species i;
MF_i = mole fraction of fuel species i;

<u>CH_4:</u>

CH_4 emissions are calculated utilizing the following equation:

$CH_4 = 0.001 \times EF_{CH4} \times Fuel$ (Equation C-8b, 40 CFR Part 98.33)

Where: EF_{CH4} = Emission Factor for CH_4 (from Table C-2, 40 CFR Part 98, Subpart C, 0.003 Kg/MMBtu;
Fuel = Annual liquid fuel use, MMBtu/yr;

<u>N_2O:</u>

N_2O emissions are calculated utilizing the following equation:

$N_2O = 0.001 \times EF_{N2O} \times Fuel$ (Equation C-8b, 40 CFR Part 98.33)

Where: EF_{CH4} = Emission Factor for CH_4 (from Table C-2, 40 CFR Part 98, Subpart C, 0.0006 Kg/MMBtu;
Fuel = Annual liquid fuel use, MMBtu/yr;

Emissions Calculation Basis (Cases A – D)

- Fuel gas combusted consists of combined stream of pipeline quality natural gas and off-gas from various process vents within the methanol process;
- Fuel use rate, higher heating value, and composition determined from process simulations for post-project plant operation;
- Annual operating hours of 8,760 hr/yr;

Emissions Calculation Basis (Baseline Case)

- Fuel gas combusted consists of combined stream of pipeline quality natural gas and off-gas from various process vents within the methanol process;
- Fuel composition and higher heating value determined from engineering calculations based on process flow sheets of the current process;
- Fuel use for 2003 and 2004 is actual fuel combusted as reported in emission inventories for calendar years 2003 and 2004;
- Stripper tails composition based on current Permit 901 representations;

The following table summarizes the greenhouse gas emissions for each of the operating cases and the baseline case. TCEQ Table 6 and detailed emissions calculations for each of the operating cases and the baseline case are included on the following pages.

	CASE A	CASE B	CASE C	Case D	Baseline (2003-2004)
CO_2 (tpy)	299,638.4	980,077.9	927,711.1	1,260,266.9	943,842.9
CH_4 (tpy)	74.9	60.2	78.6	62.6	50.2
N_2O (tpy)	15.0	12.0	15.7	12.5	10.0

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CASE A:
Methanol Plant Stand Alone Operation (W/O CO2 Addition)

Constituent i	Mol Wt i	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2	2.016	71.574	0	0.00	0.00
CO	28.01	0.894	1	12.01	0.43
CO2	44.01	2.323	1	12.01	0.27
N2	28.01	0.242	0	0.00	0.00
CH4	16.04	23.432	1	12.01	0.75
ETHANE	30.07	0.344	2	24.02	0.80
PROPANE	44.11	0.037	3	36.03	0.82
N-BUTANE	58.13	0.006	4	48.04	0.83
I-BUTANE	58.13	0.007	4	48.04	0.83
N-PENTANE	72.15	0.001	5	60.05	0.83
I-PENTANE	72.15	0.002	5	60.05	0.83
HEXANES+	86.18	0.007	6	72.06	0.84
DIMETHYL ETHER	46.07	0.082	2	24.02	0.52
CH3OH	32.04	1.005	1	12.01	0.37
H2O	18.02	0.044	0	0.00	0.00
Carbon Content	0.193	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100			

CASE A Continued

Basis

Typical Fuel Gas Rate (Incl Nat Gas)	5.29	MMscf/hr
Average Molecular Weight	7.05	kg/kg-mol
Average Fuel HHV	489.18	Btu/scf
Molar Volume Conversion Factor (MVC)	849.5	scf/kg-mol
Annual Op Hrs	8760	hr/yr
Annual Firing Rate (Fuel Gas)	22,649,176	MMBtu/yr

CH4 Emission Factor	0.003	kg/MMBtu
N2O Emission Factor	0.0006	kg/MMBtu

Emissions

CO2 Potential to Emit	271,827.7	Metric Tons CO2/yr
CO2 Potential to Emit	299,638.4	Tons CO2/yr

CH4 Potential to Emit	67.9	Metric Tons CH4/yr
CH4 Potential to Emit	74.9	Tons CH4/yr

N2O Potential to Emit	13.6	Metric Tons N2O/yr
N2O Potential to Emit	15.0	Tons N2O/yr

	Global Warming Potential	CO2e (Metric	CO2e
CO2	1	271827.7	299,638.4
CH4	21	1426.9	1572.9
N2O	310	4212.7	4643.8
		Total CO2e	305,855.0

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CASE B:
Methanol Plant Stand Alone Operation (With CO2 Addition)

Constituent i	Mol Wt i	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2	2.016	20.705	0	0.00	0.00
CO	28.01	1.832	1	12.01	0.43
CO2	44.01	8.450	1	12.01	0.27
N2	28.01	0.760	0	0.00	0.00
CH4	16.04	65.446	1	12.01	0.75
ETHANE	30.07	1.172	2	24.02	0.80
PROPANE	44.11	0.126	3	36.03	0.82
N-BUTANE	58.13	0.021	4	48.04	0.83
I-BUTANE	58.13	0.022	4	48.04	0.83
N-PENTANE	72.15	0.005	5	60.05	0.83
I-PENTANE	72.15	0.008	5	60.05	0.83
HEXANES+	86.18	0.024	6	72.06	0.84
DIMETHYL ETHER	46.07	0.117	2	24.02	0.52
CH3OH	32.04	1.239	1	12.01	0.37
H2O	18.02	0.075	0	0.00	0.00
Carbon Content	0.537	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100			

CASE B Continued
Basis

Typical Fuel Gas Rate (Incl Nat Gas)	2.69	MMscf/hr
Average Molecular Weight	16.29	kg/kg-mol
Average Fuel HHV	773.16	Btu/scf
Molar Volume Conversion Factor (MVC)	849.5	scf/kg-mol
Annual Op Hrs	8760	hr/yr
Annual Firing Rate (Fuel Gas)	18,202,689	MMBtu/yr

CH_4 Emission Factor	0.003	kg/MMBtu
N_2O Emission Factor	0.0006	kg/MMBtu

Emissions

CO_2 Potential to Emit	889,112.8	Metric Tons CO_2/yr
CO_2 Potential to Emit	980,077.9	Tons CO_2/yr

CH_4 Potential to Emit	54.6	Metric Tons CH_4/yr
CH_4 Potential to Emit	60.2	Tons CH_4/yr

N_2O Potential to Emit	10.9	Metric Tons N_2O/yr
N_2O Potential to Emit	12.0	Tons N_2O/yr

	Global Warming Potential	CO_2e (Metric	CO_2e
CO_2	1	889112.8	980,077.9
CH_4	21	1146.8	1264.1
N_2O	310	3385.7	3732.1
		Total CO_2e	985,074.1

CASE C:
Methanol and Ammonia Plant in Operation (W/O CO2 Addition)

Constituent i	Mol Wt i	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2	2.016	33.772	0	0.00	0.00
CO	28.01	1.250	1	12.01	0.43
CO2	44.01	3.657	1	12.01	0.27
N2	28.01	0.159	0	0.00	0.00
CH4	16.04	58.330	1	12.01	0.75
ETHANE	30.07	1.024	2	24.02	0.80
PROPANE	44.11	0.110	3	36.03	0.82
N-BUTANE	58.13	0.019	4	48.04	0.83
I-BUTANE	58.13	0.019	4	48.04	0.83
N-PENTANE	72.15	0.004	5	60.05	0.83
I-PENTANE	72.15	0.007	5	60.05	0.83
HEXANES+	86.18	0.021	6	72.06	0.84
DIMETHYL ETHER	46.07	0.118	2	24.02	0.52
CH3OH	32.04	1.448	1	12.01	0.37
H2O	18.02	0.063	0	0.00	0.00
Carbon Content	0.468	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100			

CASE C Continued
Basis

Typical Fuel Gas Rate (Incl Nat Gas)	3.67	MMscf/hr
Average Molecular Weight	12.97	kg/kg-mol
Average Fuel HHV	740.15	Btu/scf
Molar Volume Conversion Factor (MVC)	849.5	scf/kg-mol
Annual Op Hrs	8760	hr/yr
Annual Firing Rate (Fuel Gas)	23,778,802	MMBtu/yr

CH4 Emission Factor	0.003	kg/MMBtu
N2O Emission Factor	0.0006	kg/MMBtu

Emissions

CO2 Potential to Emit	841,606.3	Metric Tons CO2/yr
CO2 Potential to Emit	927,711.1	Tons CO2/yr

CH4 Potential to Emit	71.3	Metric Tons CH4/yr
CH4 Potential to Emit	78.6	Tons CH4/yr

N2O Potential to Emit	14.3	Metric Tons N2O/yr
N2O Potential to Emit	15.7	Tons N2O/yr

	Global Warming Potential	CO2e (Metric	CO2e
CO2	1	841,606.3	927,711.1
CH4	21	1498.1	1651.3
N2O	310	4422.9	4875.4
		Total CO2e	934,237.8

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CASE D:
Methanol and Ammonia Plant in Operation (With CO2 Addition)

Constituent i	Mol Wt i	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2	2.016	4.768	0	0.00	0.00
CO	28.01	1.999	1	12.01	0.43
CO2	44.01	9.373	1	12.01	0.27
N2	28.01	0.165	0	0.00	0.00
CH4	16.04	80.401	1	12.01	0.75
ETHANE	30.07	1.470	2	24.02	0.80
PROPANE	44.11	0.158	3	36.03	0.82
N-BUTANE	58.13	0.027	4	48.04	0.83
I-BUTANE	58.13	0.028	4	48.04	0.83
N-PENTANE	72.15	0.006	5	60.05	0.83
I-PENTANE	72.15	0.009	5	60.05	0.83
HEXANES+	86.18	0.030	6	72.06	0.84
DIMETHYL ETHER	46.07	0.128	2	24.02	0.52
CH3OH	32.04	1.358	1	12.01	0.37
H2O	18.02	0.082	0	0.00	0.00
Carbon Content	0.656	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100			

CASE D Continued
Basis

Typical Fuel Gas Rate (Incl Nat Gas)	2.45	MMscf/hr
Average Molecular Weight	18.81	kg/kg-mol
Average Fuel HHV	881.09	Btu/scf
Molar Volume Conversion Factor (MVC)	849.5	scf/kg-mol
Annual Op Hrs	8760	hr/yr
Annual Firing Rate (Fuel Gas)	18,918,456	MMBtu/yr

CH4 Emission Factor	0.003	kg/MMBtu
N2O Emission Factor	0.0006	kg/MMBtu

Emissions

CO2 Potential to Emit	1,143,296.3	Metric Tons CO2/yr
CO2 Potential to Emit	1,260,266.9	Tons CO2/yr

CH4 Potential to Emit	56.8	Metric Tons CH4/yr
CH4 Potential to Emit	62.6	Tons CH4/yr

N2O Potential to Emit	11.4	Metric Tons N2O/yr
N2O Potential to Emit	12.5	Tons N2O/yr

	Global Warming Potential	CO2e (Metric	CO2e
CO2	1	1,143,296.3	1,260,266.9
CH4	21	1191.9	1313.8
N2O	310	3518.8	3878.8
		Total CO2e	1,265,459.6

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Baseline Case

Constituent i	Mol Wt i	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
CO2	44.01	7.550	1	12.01	0.27
CO	28.01	2.553	1	12.01	0.43
H2	2.016	10.844	0	0.00	0.00
CH4	16.04	74.544	1	12.01	0.75
N2	28.01	0.309	0	0.00	0.00
H2O	18.02	0.000	0	0.00	0.00
CH3OH	32.04	0.553	1	12.01	0.37
ETHANE	30.07	2.853	2	24.02	0.80
PROPANE	44.11	0.609	3	36.03	0.82
BUTANE	58.13	0.111	4	48.04	0.83
DIMETHYL ETHER	46.07	0.011	2	24.02	0.52
METHYL FORMATE	60.05	0.041	2	24.02	0.40
METHYLAL	76.09	0.021	3	36.03	0.47
ACETONE	58.08	0.001	3	36.03	0.62
Carbon Content	0.621	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100			

Stripper Tails (To be removed as a result of the addition of the Saturator)

Constituent i	Mol Wt i (lb/lb-mol)	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
ETHANOL	46.07	3.539	2	24.02	0.52
I-BUTANOL	74.122	0.009	4	48.04	0.65
I-PROPANOL	60.1	0.324	3	36.03	0.60
METHANOL	32.04	3.349	1	12.01	0.37
N-BUTANOL	74.12	0.055	4	48.04	0.65
N-PROPANOL	60.1	0.004	3	36.03	0.60
WATER	18.02	92.719	0	0	0.00
Carbon Content	0.033	kg C/gal fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100			

Baseline Case Continued
Basis

Baseline Fuel Gas Rate (Incl Nat Gas) (2003- 2004)	18,029.3	MMscf/yr
Baseline Firing Rate (2003 - 2004)	15,131,978	MMBtu/yr
Average Molecular Weight	17.714	kg/kg-mol
Average Fuel HHV	839.3	Btu/scf
Molar Volume Conversion Factor (MVC)	849.5	scf/kg-mol
Annual Stripper Tails Fired	4,026,852	gallons
Annual Heat Release from Stripper Tails Combustion	51,716	MMBtu/yr

CH_4 Emission Factor	0.003	kg/MMBtu
N_2O Emission Factor	0.0006	kg/MMBtu

Emissions

CO_2 Potential to Emit (Fuel Gas Combustion)	855,748.0	Metric Tons CO_2/yr
CO_2 Potential to Emit (Stripper Tails Combustion)	493.0	Metric Tons CO_2/yr
CO_2 Potential to Emit (Fuel Gas + Stripper Tails)	943,842.9	Tons CO_2/yr

CH_4 Potential to Emit (Fuel Gas Combustion)	45.4	Metric Tons CH_4/yr
CH_4 Potential to Emit (Stripper Tails Combustion)	0.2	Metric Tons CH_4/yr
CH_4 Potential to Emit (Fuel Gas + Stripper Tails)	50.2	Tons CH_4/yr

N_2O Potential to Emit	9.1	Metric Tons N_2O/yr
N_2O Potential to Emit (Stripper Tails Combustion)	0.03	Metric Tons N_2O/yr
N_2O Potential to Emit (Fuel Gas + Stripper Tails)	10.0	Tons N_2O/yr

	Global Warming Potential	CO_2e (Metric Tons/yr)	CO_2e (Tons/yr)
CO_2	1	856240.9	943,842.9
CH_4	21	956.6	1054.4
N_2O	310	2824.2	3113.1
		Total CO_2e	948,010.5

TABLE 6

BOILERS AND HEATERS

Type of Device: North and South Reforming Furnaces					Manufacturer: Foster Wheeler		
Number from flow diagram: EPN STK41					Model Number: 71-9110-01		
CHARACTERISTICS OF INPUT							
Type Fuel	Chemical Composition (% by weight)		Inlet Air Temp °F (Ambient)		Fuel Flow Rate (scfm* or lb/hr)		
Fuel Gas	Hydrogen 33.77% CO 1.25% CO_2 3.66% Nitrogen 0.16% Methane 58.32% Ethane/ene 1.02% Propane/ene 0.11% Butane/ene 0.04% Pentane/ene 0.01% Hexanes Plus 0.02% Dimethyl Ether 0.12% Methanol 1.45% Water 0.06%		23 deg. C		Average 61,116.67 scfm	Design Maximum 61,116.67 scfm	
			Avg. Gross Heating Value of Fuel		Total Air Supplied and Excess Air		
			(specify units) 450 - 900 Btu/scf HHV		Average 144,500 scfm* 10 % excess (vol)	Design Maximum 178,600 scfm* 10 % excess (vol)	
HEAT TRANSFER MEDIUM							
Type Transfer Medium (Water, oil, etc.)	Temperature °F		Pressure (psia)		Flow Rate (specify units)		
	Input	Output	Input	Output	Average	Design Maxim	
Steam	345	800	1665	1515	700,000 lb/hr	1,000,000 lb/hr	

OPERATING CHARACTERISTICS			
Ave. Fire Box Temp. at max. firing rate	Fire Box Volume (ft.3), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)
1970 F	54,020	5.61	8.91

STACK PARAMETERS					
Stack diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas Temp °F	Exhaust scfm
		(@Ave. Fuel Flow Rate	(@Max. Fuel Flow Rate		
TBD	TBD	TBD	TBD	TBD	TBD

CHARACTERISTICS OF OUTPUT	
Material	Chemical Composition of Exit Gas Released (% by Volume)
	See Table 1(a).
Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.	

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit. Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F, 14.7 psia

4.2 Pre-Reformer Fired Heater (EPNs: PRFMHTR)

The Pre-Reformer Fired Heater is utilized to preheat the feed to the pre-reformer and to preheat the pre-reformer effluent prior to introduction into the North and South steam reformers. The Pre-Reformer Fired Heater will operate with different heat input from natural gas depending on the specific case that the steam reformers are operating. The four different operating modes of the steam reformers as follows:

Case A: Methanol plant stand-alone operation (without CO_2 addition)
Case B: Methanol plant stand-alone operation (with CO_2 addition)
Case C: Methanol and Ammonia plant production (without CO_2 addition)
Case D: Methanol and Ammonia plant production (with CO_2 addition)

In order to determine the worst-case greenhouse gas emissions for each of the operating modes, emissions were calculated for each operating case and compared. The results of this analysis indicate that Case C will result in the worst-case emissions; therefore, Case C will be considered as the potential to emit. Planned MSS operations for the Pre-Reformer Fired Heater are not expected generate GHG mass emissions greater than any of the normal operating cases.

Emission Calculation Methodology (Gaseous Fuel)

<u>CO_2:</u>

CO_2 emissions are calculated utilizing the following equation:

$$CO_2 = \frac{44}{12} \times Fuel \times CC \times \frac{MW}{MVC} \times 0.001$$ (Equation C-5, 40 CFR Part 98.33)

Where:
CO_2 = Carbon dioxide emissions in metric tons per year;
44/12 = Ratio of molecular weights of CO_2 to carbon;
Fuel = Annual volume of gaseous fuel combusted, scf;
CC = Carbon content of gaseous fuel combusted, Kg. C / Kg. fuel;
MW = Average molecular weight of gaseous fuel, Kg/Kg-mol;
MVC = Molar conversion factor, 849.5 scf/Kg-mol (@ 68°F);
0.001 = Conversion factor from Kg to metric tons;

The carbon content of the gaseous fuel is calculated utilizing the following methodology:

$$CC = \sum(CF_i \times MF_i)/100$$

Where: CF_i = Carbon fraction of fuel species i;
MF_i = mole fraction of fuel species i;

The carbon fraction for each fuel species contained in the fuel is calculated utilizing the following methodology:

$$CF_i = C_i \div MW_i$$

Where: C_i = Carbon weight of fuel species i;
MW_i = Molecular weight of fuel species i;

The average molecular weight of the gaseous fuel is calculated utilizing the following methodology:

$$MW = \sum(MW_i \times MF_i)$$

Where: MW_i = Molecular weight of fuel species i;
MF_i = mole fraction of fuel species i;

<u>CH_4:</u>

CH_4 emissions are calculated utilizing the following equation:

$$CH_4 = 0.001 \times EF_{CH4} \times Fuel$$ (Equation C-8b, 40 CFR Part 98.33)

Where: EF_{CH4} = Emission Factor for CH_4 (from Table C-2, 40 CFR Part 98, Subpart C) 0.003 Kg/MMBtu;
Fuel = Annual gaseous fuel use, MMBtu/yr;

N_2O:

N_2O emissions are calculated utilizing the following equation:

$$N_2O = 0.001 \times EF_{N2O} \times Fuel$$ (Equation C-8b, 40 CFR Part 98.33)

Where: EF_{CH4} = Emission Factor for CH_4 (from Table C-2, 40 CFR Part 98, Subpart C, 0.0006 Kg/MMBtu;
Fuel = Annual gaseous fuel use, MMBtu/yr;

Emissions Calculation Basis (Cases A – D)

- Fuel gas combusted is pipeline quality natural gas;
- Fuel use rate determined from process simulations for post-project plant operation;
- Higher heating value and composition are typical for natural gas;
- Annual operating hours of 8,760 hr/yr;

The following table summarizes the greenhouse gas emissions for each of the operating cases and the baseline case. TCEQ Table 6 and detailed emissions calculations for each of the operating cases and the baseline case are included on the following pages.

	CASE A	CASE B	CASE C	Case D
CO_2 (tpy)	164,122.2	127,627.0	164,232.5	127,627.0
CH_4 (tpy)	9.3	7.2	9.3	7.2
N_2O (tpy)	1.9	1.4	1.9	1.4

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Pre-Reformer Fired Heater - EPN: PRFMHTR
CASE A:
Methanol Plant Stand Alone Operation (W/O CO2 Addition)

Constituent i	Mol Wt i	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2	2.016	0.000	0	0.00	0.00
CO	28.01	0.000	1	12.01	0.43
CO2	44.01	1.189	1	12.01	0.27
N2	28.01	0.229	0	0.00	0.00
CH4	16.04	96.189	1	12.01	0.75
ETHANE	30.07	2.037	2	24.02	0.80
PROPANE	44.11	0.219	3	36.03	0.82
N-BUTANE	58.13	0.037	4	48.04	0.83
I-BUTANE	58.13	0.038	4	48.04	0.83
N-PENTANE	72.15	0.008	5	60.05	0.83
I-PENTANE	72.15	0.013	5	60.05	0.83
HEXANES+	86.18	0.041	6	72.06	0.84
H2O	18.02	0.000	0	0.00	0.00

Carbon Content	0.743	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100

CASE A Continued

Basis

Typical Fuel Gas Rate (Nat Gas)	0.32	MMscf/hr
Average Molecular Weight	16.82	kg/kg-mol
Average Fuel HHV	1020	Btu/scf
Molar Volume Conversion Factor (MVC)	849.5	scf/kg-mol
Annual Op Hrs	8760	hr/yr
Annual Firing Rate (Nat Gas)	2,816,773	MMBtu/yr

CH4 Emission Factor	0.003	kg/MMBtu
N2O Emission Factor	0.0006	kg/MMBtu

Emissions

CO2 Potential to Emit	148,889.3	Metric Tons CO2/yr
CO2 Potential to Emit	164,122.2	Tons CO2/yr

CH4 Potential to Emit	8.5	Metric Tons CH4/yr
CH4 Potential to Emit	9.3	Tons CH4/yr

N2O Potential to Emit	1.7	Metric Tons N2O/yr
N2O Potential to Emit	1.9	Tons N2O/yr

	Global Warming Potential	CO2e (Metric Tons/yr)	CO2e (Tons/yr)
CO2	1	148889.3	164,122.2
CH4	21	177.5	195.6
N2O	310	523.9	577.5
		Total CO2e	164,895.3

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Pre-Reformer Fired Heater - EPN: PRFMHTR
CASE B:
Methanol Plant Stand Alone Operation (With CO2 Addition)

Constituent i	Mol Wt i	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2	2.016	0.000	0	0.00	0.00
CO	28.01	0.000	1	12.01	0.43
CO2	44.01	1.189	1	12.01	0.27
N2	28.01	0.229	0	0.00	0.00
CH4	16.04	96.189	1	12.01	0.75
ETHANE	30.07	2.037	2	24.02	0.80
PROPANE	44.11	0.219	3	36.03	0.82
N-BUTANE	58.13	0.037	4	48.04	0.83
I-BUTANE	58.13	0.038	4	48.04	0.83
N-PENTANE	72.15	0.008	5	60.05	0.83
I-PENTANE	72.15	0.013	5	60.05	0.83
HEXANES+	86.18	0.041	6	72.06	0.84
H2O	18.02	0.000	0	0.00	0.00
Carbon Content	0.743	kg C/kg fuel (= Σ Carbon Fraction_i*$\text{Mol\%}_i$) / 100			

CASE B Continued
Basis

Typical Fuel Gas Rate (Nat Gas)	0.25	MMscf/hr
Average Molecular Weight	16.82	kg/kg-mol
Average Fuel HHV	1020	Btu/scf
Molar Volume Conversion Factor (MVC)	849.5	scf/kg-mol
Annual Op Hrs	8760	hr/yr
Annual Firing Rate (Nat Gas)	2,190,418	MMBtu/yr

CH4 Emission Factor	0.003	kg/MMBtu
N2O Emission Factor	0.0006	kg/MMBtu

Emissions

CO2 Potential to Emit	115,781.4	Metric Tons CO2/yr
CO2 Potential to Emit	127,627.0	Tons CO2/yr

CH4 Potential to Emit	6.6	Metric Tons CH4/yr
CH4 Potential to Emit	7.2	Tons CH4/yr

N2O Potential to Emit	1.3	Metric Tons N2O/yr
N2O Potential to Emit	1.4	Tons N2O/yr

	Global Warming Potential	CO2e (Metric Tons/yr)	CO2e (Tons/yr)
CO2	1	115781.4	127,627.0
CH4	21	138.0	152.1
N2O	310	407.4	449.1
		Total CO2e	128,228.2

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Pre-Reformer Fired Heater - EPN: PRFMHTR
CASE C:
Methanol and Ammonia Plant in Operation (W/O CO2 Addition)

Constituent i	Mol Wt i	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2	2.016	0.000	0	0.00	0.00
CO	28.01	0.000	1	12.01	0.43
CO2	44.01	1.189	1	12.01	0.27
N2	28.01	0.229	0	0.00	0.00
CH4	16.04	96.189	1	12.01	0.75
ETHANE	30.07	2.037	2	24.02	0.80
PROPANE	44.11	0.219	3	36.03	0.82
N-BUTANE	58.13	0.037	4	48.04	0.83
I-BUTANE	58.13	0.038	4	48.04	0.83
N-PENTANE	72.15	0.008	5	60.05	0.83
I-PENTANE	72.15	0.013	5	60.05	0.83
HEXANES+	86.18	0.041	6	72.06	0.84
H2O	18.02	0.000	0	0.00	0.00
Carbon Content	0.743	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100			

CASE C Continued

Basis

Typical Fuel Gas Rate (Nat Gas)	0.32	MMscf/hr
Average Molecular Weight	16.82	kg/kg-mol
Average Fuel HHV	1020	Btu/scf
Molar Volume Conversion Factor (MVC)	849.5	scf/kg-mol
Annual Op Hrs	8760	hr/yr
Annual Firing Rate (Nat Gas)	2,818,666	MMBtu/yr

CH4 Emission Factor	0.003	kg/MMBtu
N2O Emission Factor	0.0006	kg/MMBtu

Emissions

CO2 Potential to Emit	148,989.4	Metric Tons CO2/yr
CO2 Potential to Emit	164,232.5	Tons CO2/yr

CH4 Potential to Emit	8.5	Metric Tons CH4/yr
CH4 Potential to Emit	9.3	Tons CH4/yr

N2O Potential to Emit	1.7	Metric Tons N2O/yr
N2O Potential to Emit	1.9	Tons N2O/yr

	Global Warming Potential	CO2e (Metric Tons/yr)	CO2e (Tons/yr)
CO2	1	148,989.4	164,232.5
CH4	21	177.6	195.7
N2O	310	524.3	577.9
		Total CO2e	165,006.1

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Pre-Reformer Fired Heater - EPN: PRFMHTR
CASE D:
Methanol and Ammonia Plant in Operation (With CO2 Addition)

Constituent i	Mol Wt i	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2	2.016	0.000	0	0.00	0.00
CO	28.01	0.000	1	12.01	0.43
CO2	44.01	1.189	1	12.01	0.27
N2	28.01	0.229	0	0.00	0.00
CH4	16.04	96.189	1	12.01	0.75
ETHANE	30.07	2.037	2	24.02	0.80
PROPANE	44.11	0.219	3	36.03	0.82
N-BUTANE	58.13	0.037	4	48.04	0.83
I-BUTANE	58.13	0.038	4	48.04	0.83
N-PENTANE	72.15	0.008	5	60.05	0.83
I-PENTANE	72.15	0.013	5	60.05	0.83
HEXANES+	86.18	0.041	6	72.06	0.84
H2O	18.02	0.000	0	0.00	0.00
Carbon Content	0.743	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100			

CASE D Continued

Basis

Typical Fuel Gas Rate (Nat Gas)	0.25	MMscf/hr
Average Molecular Weight	16.82	kg/kg-mol
Average Fuel HHV	1020	Btu/scf
Molar Volume Conversion Factor (MVC)	849.5	scf/kg-mol
Annual Op Hrs	8760	hr/yr
Annual Firing Rate (Nat Gas)	2,190,418	MMBtu/yr

CH4 Emission Factor	0.003	kg/MMBtu
N2O Emission Factor	0.0006	kg/MMBtu

Emissions

CO2 Potential to Emit	115,781.4	Metric Tons CO2/yr
CO2 Potential to Emit	127,627.0	Tons CO2/yr

CH4 Potential to Emit	6.6	Metric Tons CH4/yr
CH4 Potential to Emit	7.2	Tons CH4/yr

N2O Potential to Emit	1.3	Metric Tons N2O/yr
N2O Potential to Emit	1.4	Tons N2O/yr

	Global Warming Potential	CO2e (Metric Tons/yr)	CO2e (Tons/yr)
CO2	1	115,781.4	127,627.0
CH4	21	138.0	152.1
N2O	310	407.4	449.1
		Total CO2e	128,228.2

TABLE 6

BOILERS AND HEATERS

<table>
<tr><td colspan="4">Type of Device: Pre-Reformer Fired Heater</td><td colspan="4">Manufacturer: TBD</td></tr>
<tr><td colspan="4">Number from flow diagram: EPN PRFMHTR</td><td colspan="4">Model Number: TBD</td></tr>
<tr><td colspan="8">CHARACTERISTICS OF INPUT</td></tr>
<tr><td colspan="2">Type Fuel</td><td colspan="2">Chemical Composition
(Avg. % by weight)</td><td colspan="2">Inlet Air Temp °F
(Ambient)</td><td colspan="2">Fuel Flow Rate
(scfm* or lb/hr)</td></tr>
<tr><td colspan="2" rowspan="8">Natural Gas</td><td>CO_2</td><td>1.19%</td><td colspan="2" rowspan="2">Ambient</td><td rowspan="2">Average
5,333.33 scfm</td><td rowspan="2">Design Maximum
5,333.33 scfm</td></tr>
<tr><td>Nitrogen</td><td>0.23%</td></tr>
<tr><td>Methane</td><td>96.19%</td><td colspan="2" rowspan="2">Avg. Gross Heating Value of Fuel</td><td colspan="2" rowspan="2">Total Air Supplied and Excess Air</td></tr>
<tr><td>Ethane/ene</td><td>2.04%</td></tr>
<tr><td>Propane/ene</td><td>0.22%</td><td colspan="2" rowspan="4">(specify units)

1050 Btu/scf HHV</td><td>Average</td><td>Design Maximum</td></tr>
<tr><td>Butane/ene</td><td>0.08%</td><td>4,080 scfm*</td><td>5,100 scfm*</td></tr>
<tr><td>Pentane/ene</td><td>0.02%</td><td>10 % excess</td><td>10 % excess</td></tr>
<tr><td>Hexanes Plus</td><td>0.04%</td><td>(vol)</td><td>(vol)</td></tr>
<tr><td colspan="8">HEAT TRANSFER MEDIUM</td></tr>
<tr><td colspan="2" rowspan="2">Type Transfer Medium
(Water, oil, etc.)</td><td colspan="2">Temperature °F</td><td colspan="2">Pressure (psia)</td><td colspan="2">Flow Rate (specify units)</td></tr>
<tr><td>Input</td><td>Output</td><td>Input</td><td>Output</td><td>Average</td><td>Design Maxim</td></tr>
<tr><td colspan="2"></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="8">OPERATING CHARACTERISTICS</td></tr>
<tr><td colspan="2">Ave. Fire Box Temp.
at max. firing rate</td><td colspan="3">Fire Box Volume (ft.3),
(from drawing)</td><td colspan="2">Gas Velocity in Fire Box (ft/sec)
at max firing rate</td><td>Residence Time
in Fire Box
at max firing rate (sec)</td></tr>
<tr><td colspan="2">TBD</td><td colspan="3">TBD</td><td colspan="2">TBD</td><td>TBD</td></tr>
<tr><td colspan="8">STACK PARAMETERS</td></tr>
<tr><td rowspan="2">Stack diameters</td><td rowspan="2">Stack Height</td><td colspan="4">Stack Gas Velocity (ft/sec)</td><td rowspan="2">Stack Gas
Temp °F</td><td rowspan="2">Exhaust
scfm</td></tr>
<tr><td colspan="2">(@Ave. Fuel Flow Rate</td><td colspan="2">(@Max. Fuel Flow Rate</td></tr>
<tr><td>TBD</td><td>TBD</td><td colspan="2">TBD</td><td colspan="2">TBD</td><td>TBD</td><td>TBD</td></tr>
<tr><td colspan="8">CHARACTERISTICS OF OUTPUT</td></tr>
<tr><td>Material</td><td colspan="7">Chemical Composition of Exit Gas Released (% by Volume)</td></tr>
<tr><td></td><td colspan="7">See Table 1(a).</td></tr>
<tr><td colspan="8">Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.</td></tr>
</table>

Also supply an assemhly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit. Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F, 14.7 psia

4.3 Methanol Plant Flare (EPN: 45)

The methanol plant flare combusts gases during normal, upset and MSS periods. Both the methanol and ammonia production units can use this flare. Process purge gas from normal operations may also be used as fuel gas for the reformers. The flare is equipped with continuous burning pilots. As part of this debottlenecking project, the DME eductor maintenance emissions are being routed to the methanol plant flare rather than to atmosphere. The project will also change the status of the stripper tails tank from a tank to a process vessel and the vent will be routed to the flare. This will result increased emissions of greenhouse gases from the flare. Emissions for this flare are calculated per the methods in 40 CFR Part 98, Subpart Y. The basis for the emission calculations is defined as follows:

Emissions Basis

Stripper Tails Vent (Normal Operations)

- From Methanol Plant – average flow to flare = 499.8 lb/hr

Methanol Plant Startups and Shutdowns (MSS)

- From Methanol Plant - maximum flow to flare = 57,520 lb/hr
- 4 methanol plant startups and shutdowns / yr
- 8 hours per startup event
- 4 hours per shutdown event

DME Compressor Vent (MSS)

- Maximum flow to flare = 3253.70 lb/hr
- Annual maintenance venting to flare = 40 hr/yr

$\underline{CO_2}$:

CO_2 emissions are calculated utilizing the following equation:

$$CO_2 = 0.98 \times 0.001 \times \left(\left(\sum Flare_{Norm} \times HHV \times EmF\right) + \sum \left[\frac{44}{12} \times (Flare_{ssm}) \times \frac{MW}{MVC} \times CC \right] \right)$$ (Equation Y-3, 40 CFR Part 98.253)

Where: CO_2 = Carbon dioxide emissions in metric tons per year;
0.98 = Assumed combustion efficiency of the flare;
0.001 = Conversion factor from Kg to metric tons;

$Flare_{Norm}$ = Annual volume of flare gas combusted during normal operations (Pilot Gas and Stripper Tails), MMscf/yr;
HHV = Higher heating value for fuel gas or flare gas, MMBtu/MMscf;
EmF = Default CO_2 emission factor for flare gas, 60 Kg CO_2 / MMBtu (high heat basis);
44 = molecular weight of CO_2, Kg/Kg-mol;
12 = atomic weight of C, Kg/Kg-mol;
$Flare_{ssm}$ = Volume of gas combusted during start-up or shutdown event from engineering calculations (startups/shutdowns and DME Compressor Vent), scf/event;
MW = Average molecular weight of the flare gas from engineering calculations for each event, kg/kg-mol,
MVC = Molar conversion factor, 849.5 scf/Kg-mol (@ 68°F);
CC = Average carbon content of the flare gas from engineering calculations for each event, Kg C / Kg flare gas;

$\underline{CH_4:}$

CH_4 emissions are calculated utilizing the following equation:

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH_4}}{EmF}\right) + CO_2 \times \frac{0.02}{98} \times \frac{16}{44} \times f_{CH_4} \text{ (Equation Y-4, 40 CFR Part 98.253)}$$

Where:

CH_4 = Annual methane emissions from flared gas, MT CH_4/yr;
CO_2 = Carbon dioxide emissions from equation Y-3 above, MT/yr;
EmF_{CH4} = Default CH_4 emission factor for "Petroleum Products" from Table C-2 of Subpart C, Kg CH_4 / MMBtu;
EmF = Default CO_2 emission factor for flare gas, 60 Kg CO_2 / MMBtu (high heat basis);
0.02/0.98 = Correction factor for flare combustion efficiency;
16/44 = Correction factor ratio of the molecular weight of CH_4 to CO_2;
f_{CH4} = Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from engineering calculations, Kg C from methane / Kg C in flare gas;

$\underline{N_2O:}$

N_2O emissions are calculated utilizing the following equation:

$$N_2O = \left(CO_2 \times \frac{EmF_{N2O}}{EmF}\right) \text{ (Equation Y-6, 40 CFR Part 98.253)}$$

Where: N_2O = Annual nitrous oxide emissions from flared gas, MT N_2O/yr;
CO_2 = Carbon dioxide emissions from equation Y-3 above, MT/yr;
EmF_{N2O} = Default N_2O emission factor for "Petroleum Products" from Table C-2 of Subpart C, Kg N_2O / MMBtu;
EmF = Default CO_2 emission factor for flare gas, 60 Kg CO_2 / MMBtu (high heat basis);

The following table summarizes the greenhouse gas emissions for the Methanol Plant Flare. TCEQ Table 8 and detailed emissions calculations for the flare are included on the following pages.

	EPN: 45
CO_2 (tpy)	10,995
CH_4 (tpy)	68.5
N_2O (tpy)	0.11

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Methanol Plant Flare GHG Emissions (EPN: 45)

Pilots

80 Pilot Gas Flow, scfh per pilot
3 # of pilots
14400 Total Pilot Gas Flow, scf/hr
126.14 Total Pilot Gas Flow, MMscf/yr

Stripper Tails Tank Vent (Normal Operations)

499.8 lb/hr
385.16 scf/lb-mol
8,760 Annual Operating Hours

Typical Waste Gas Flow Rate	0.0071	MMscf/hr
Average Molecular Weight	26.97	kg/kg-mol
Average Fuel HHV	539.45	Btu/scf
Molar Volume Conversion Factor	849.5	scf/kg-mol
Annual Firing Rate (Waste Gas)	33,736	MMBtu/yr
Annual Firing Rate (Waste Gas)	62.5	MMscf/yr

Startup / Shutdown Flare Gas (MSS)

57,200 lb/hr
385.16 scf/lb-mol
4 Hours per Shutdown
4 # Shutdowns per year
8 Hours per Startup
4 # Startups per year

Typical Waste Gas Flow Rate	4.70	MMscf/hr
Average Molecular Weight	4.69	kg/kg-mol
Average Fuel HHV	381.37	Btu/scf
Molar Volume Conversion Factor	849.5	scf/kg-mol
Annual Firing Rate (Waste Gas)	86,006	MMBtu/yr
Annual Firing Rate (Waste Gas)	225.5	MMscf/yr

DME Eductor Maintenance (MSS)

3,254 lb/hr
385.16 scf/lb-mol

Typical Waste Gas Flow Rate	0.0306	MMscf/hr
Average Molecular Weight	40.92	kg/kg-mol
Average Fuel HHV	530.94	Btu/scf
Molar Volume Conversion Factor	849.5	scf/kg-mol
Annual Startup Hrs	40	hr/yr
Annual Firing Rate (Nat Gas)	650	MMBtu/yr
Annual Firing Rate (Waste Gas)	1.22	MMscf/yr

Carbon Content of Stripper Tails Tank Vent Gas

Constituent i	Higher Heating Value, (Btu/scf)	Mol Wt i	Typical Weight %	Weight Frac	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2O	0	18.02	29.13	0.2913	43.595	0	0	0
CH3OH	868	32	61.1000	0.611	51.492	1	12.01	0.375313
EtOH	1600	46.07	5.1200	0.0512	2.997	2	24.02	0.521381
I-propyl alcohol	2247	60.1	0.3600	0.0036	0.162	3	36.03	0.599501
n-propyl alcohol	2058	60.1	2.3200	0.0232	1.041	3	36.03	0.599501
I-butanol	2724	74.12	0.9200	0.0092	0.335	4	48.04	0.648138
n-butanol	2741	74.12	1.0400	0.0104	0.378	4	48.04	0.648138
		26.965413						

Carbon Content	0.221	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100	
CH4 Fraction	0	Kg C from methane /Kg C in Fuel)	
Stream HHV	539.4506393	High Heating Value, Btu/scf	

Carbon Content of Startup and Shutdown Flare Gas

Constituent i	Higher Heating Value, (Btu/scf)	Mol Wt i	Typical Weight %	Weight Frac	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2O	0	18	0	0	0.000	0	0	0
CH3OH	868	32	4.8100	0.0481	0.705	1	12.01	0.375313
H2	325	2.016	37.4400	0.3744	87.085	0	0	0
N2	0	28.01	1.4800	0.0148	0.248	0	0	0
CO	322	28.01	6.7100	0.0671	1.123	1	12.01	0.428775
CO2	0	44.01	19.6400	0.1964	2.093	1	12.01	0.272893
CH4	1013	16.04	29.9200	0.2992	8.747	1	12.01	0.748753
		4.68917						

Carbon Content	0.079	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100	
CH4 Fraction	0.832550096	Kg C from methane /Kg C in Fuel)	
Stream HHV	381.365933	High Heating Value, Btu/scf	

Carbon Content of DME Eductor Flare Gas

Constituent i	Higher Heating Value, (Btu/scf)	Mol Wt i	Typical Weight %	Weight Frac	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
CH3OH	868	32	35.4700	0.3547	45.352	1	12.01	0.375313
Dimethyl Ether	1627	46	1.1000	0.011	0.978	2	24.02	0.522174
Methyl Formate	1227	60	5.1000	0.051	3.478	2	24.02	0.400333
Methalal	1651	76	3.2600	0.0326	1.755	3	36.03	0.474079
Acetone	1916	58	0.1500	0.0015	0.106	3	36.03	0.621207
Acetaldehyde	1366	44	0.0900	0.0009	0.084	2	24.02	0.545909
CH4	1013	16.04	0.1400	0.0014	0.357	1	12.01	0.748753
CO2	0	44.01	46.1000	0.461	42.858	1	12.01	0.272893
Misc VOC	853	70	8.6100	0.0861	5.033	3	36.03	0.514714
		40.923134						

Carbon Content	0.344	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100	
CH4 Fraction	0.008	Kg C from methane /Kg C in Fuel)	
Stream HHV	530.9418546	High Heating Value, Btu/scf	

EMISSION CALCULATIONS

CO2 Emissions

126.14	MMscf/yr, $FLARE_{norm}$ (Pilot Gas)
1020.00	HHV (Nat Gas, MMBtu/MMscf)
62.54	MMscf/yr, $FLARE_{norm}$ (Stripper Tails Tk Vt)
539.45	HHV (Stripper Tails Tk Vt, MMBtu/MMscf)
60	Kg/MMBtu, EmF
225,520,525.97	scf/yr, FLAREssm (Startup / Shutdown)
1,224,936.01	scf/yr, FLAREssm (DME Eductor.)
4.69	Kg/Kg-mol, Avg MW of SU / SD Waste Gas
40.92	Kg/Kg-mol, Avg MW of DME Eductor Gas
849.5	scf/Kg-mol, MVC
0.079	CCp of SU/SD Flare Gas, Kg C / Kg Flare Gas
0.344	CCp ofDME Eductor., Kg C / Kg Flare Gas
9,974	MT/YR, CO2 Emissions (Eqn Y-3, 40 CFR Part 98)
10,995	Ton/yr, CO2

CH4 Emissions

0.003	EmFch4, Emission factor from Table C-2 (40 CFR Part 98)
0.83	fch4, Weight fraction of C in waste gas from SU/SD Waste Gas
62.12	MT/YR, CH4 Emissions (Eqn Y-4, 40 CFR Part 98)
68.5	Ton/yr, CH4

N2O Emissions

0.0006	EmFn2o, Emission factor from Table C-2 (40 CFR Part 98)
0.0997	MT/YR, N2O Emissions (Eqn Y-5, 40 CFR Part 98)
0.11	Ton/yr, N2O

CO2e Emissions

	Global Warming Potential	CO2e, MT/yr	CO2e, ton/yr
CO2	1	9,974	10,995
CH4	21	1,305	1,438
N2O	310	31	34
		11,309.7	**12,466.7**

TABLE 8

FLARE SYSTEMS

Number from flow diagram: EPN: 45	Manufacturer & Model No. (if available): NAO, Inc. - 24" NFF-CG (Equip. #14-9446-001)

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Maximum
Reactor Purge Gas		lb/hr	lb/hr	lb/hr
	H2O	0	728	
	CH3OH	0	4278	
	EtOH	0	128	
	I-Propyl Alcohol	0	9	
	n-Propyl Alcohol	0	58	
	I-Butanol	0	23	
	n-Butanol	0	26	
	H2	0	88117	
	N2	0	309145	
	CO	0	3838	
	CO2	0	11234	
	CH4	0	17114	
% of time this condition occurs		~99%	~1%	

	Flow Rate (scfm [68°F, 14.7 psia])		Temperature °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	0	78,333.33	100	9.5 psia
Fuel Added to Gas Stream	0	0		

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
	3	Natural Gas	1.33

For Stream Injection	Stream Pressure (psig)		Total Stream Flow	Temperature °F	Velocity (ft/sec)
	Min. Expected	Design Max.	Rate (lb/hr)		

	Number of Jet Streams	Diameter of Steam Jets (inches)	Design basis for steam injected (lb steam/lb hydrocarbon)

For Water Injection	Water Pressure (psig) Min. Expected Design Max.	Total Water Flow Rate (gpm) Min. Expected Design Max.	No. of Water Jets	Diameter of Water Jets (inches)

Flare Height (ft): 217	Flare tip inside diameter (ft): 2
Capital Installed Cost $________	Annual Operating Cost $____________

Supply an assembly drawing, dimensioned and to scale, to show clearly the operation of the flare system. Show interior dimensions and features of the equipment necessary to calculate its performance. Also describe the type of ignition system and its method of operation. Provide an explanation of the control system for steam flow rate and other operating variables.

4.4 Ammonia Plant Flare (EPN: FL321)

The ammonia plant flare combusts gases during normal, upset and MSS periods. During normal operations, the flare combusts purge gas from the ammonia plant. During planned startups and shutdowns, additional purge gas from the ammonia plant is routed to the flare for destruction. The flare is equipped with continuous burning pilots. As part of this debottlenecking project, the purge gas from normal operations will be increased proportionally to the increase in production capacity of the Ammonia Plant (12%). This increase in combusted purge gas will result increased emissions of greenhouse gases from the flare. Emissions for this flare are calculated per the methods in 40 CFR Part 98, Subpart Y. The basis for the emission calculations is defined as follows:

Emissions Basis

Pilot Gas Combustion:

- Fuel Usage: 66 scf/hr-pilot
- Number of Pilots: 3 pilots
- Typical Nat Gas Heating value: 1,020 Btu/scf
- Annual Operating Hours: 8,760 hrs/yr

Ammonia Plant Purge Gas Combustion (Normal Operations):

- Average Purge Gas to Flare: 443.5 lb/hr
- Purge Gas Heating Value
- Annual Operating Hours: 8,760 hrs/yr

Ammonia Plant Purge Gas Combustion (MSS Operations):

- Average Purge Gas to Flare: 30,870 lb/hr
- 8 planned startups and shutdowns / yr
- 4 hours per startup / shutdown event

CO_2:

CO_2 emissions are calculated utilizing the following equation:

$$CO_2 = 0.98 \times 0.001 \times \left(\left(\sum Flare_{Norm} \times HHV \times EmF \right) + \sum \left[\frac{44}{12} \times (Flare_{ssm}) \times \frac{MW}{MVC} \times CC \right] \right)$$ (Equation Y-3, 40 CFR Part 98.253)

Where: CO_2 = Carbon dioxide emissions in metric tons per year;

0.98 = Assumed combustion efficiency of the flare;

0.001 = Conversion factor from Kg to metric tons;

$Flare_{Norm}$ = Annual volume of flare gas combusted during normal operations (Pilot Gas), MMscf/yr;

HHV = Higher heating value for fuel gas or flare gas, MMBtu/MMscf;

EmF = Default CO_2 emission factor for flare gas, 60 Kg CO_2 / MMBtu (high heat basis);

44 = molecular weight of CO_2, Kg/Kg-mol;

12 = atomic weight of C, Kg/Kg-mol;

$Flare_{norm/ssm}$ = Volume of gas combusted during normal operations and start-up or shutdown event from engineering calculations (Purge gas to flare – normal and startups/shutdowns), scf/event;

MW = Average molecular weight of the flare gas from engineering calculations for each event, kg/kg-mol,

MVC = Molar conversion factor, 849.5 scf/Kg-mol (@ 68°F);

CC = Average carbon content of the flare gas from engineering calculations for each event, Kg C / Kg flare gas;

$\underline{CH_4:}$

CH_4 emissions are calculated utilizing the following equation:

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH_4}}{EmF}\right) + CO_2 \times \frac{0.02}{98} \times \frac{16}{44} \times f_{CH_4} \quad \text{(Equation Y-4, 40 CFR Part 98.253)}$$

Where:

CH_4 = Annual methane emissions from flared gas, MT CH_4/yr;

CO_2 = Carbon dioxide emissions from equation Y-3 above, MT/yr;

EmF_{CH4} = Default CH_4 emission factor for "Petroleum Products" from Table C-2 of Subpart C, Kg CH_4 / MMBtu;

EmF = Default CO_2 emission factor for flare gas, 60 Kg CO_2 / MMBtu (high heat basis);

0.02/0.98 = Correction factor for flare combustion efficiency;

16/44 = Correction factor ratio of the molecular weight of CH_4 to CO_2;

f_{CH4} = Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from engineering calculations, Kg C from methane / Kg C in flare gas;

$\underline{N_2O:}$

N_2O emissions are calculated utilizing the following equation:

$$N_2O = \left(CO_2 \times \frac{EmF_{N2O}}{EmF}\right) \text{ (Equation Y-6, 40 CFR Part 98.253)}$$

Where: N_2O = Annual nitrous oxide emissions from flared gas, MT N_2O/yr;
CO_2 = Carbon dioxide emissions from equation Y-3 above, MT/yr;
EmF_{N2O} = Default N_2O emission factor for "Petroleum Products" from Table C-2 of Subpart C, Kg N_2O / MMBtu;
EmF = Default CO_2 emission factor for flare gas, 60 Kg CO_2 / MMBtu (high heat basis);

The following table summarizes the greenhouse gas emissions for the Ammonia Plant Flare. TCEQ Table 8 and detailed emissions calculations for the flare are included on the following pages.

	EPN: FL321
CO_2 (tpy)	7,074.1
CH_4 (tpy)	51.3
N_2O (tpy)	0.07

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Ammonia Plant Flare GHG Emissions (EPN: FL321)

Pilots

66 Pilot Gas Flow, scfh per pilot
3 # of pilots
11880 Total Pilot Gas Flow, scf/hr
104.07 Total Pilot Gas Flow, MMscf/yr

Ammonia Plant Purge Gas (Normal Operations)

443.5 lb/hr
385.16 scf/lb-mol
8,760 Annual Operating Hours

Typical Waste Gas Flow Rate	0.0082	MMscf/hr
Typical Molecular Weight	20.83	kg/kg-mol
Average Fuel HHV	252.61	Btu/scf
Molar Volume Conversion Factor	849.5	scf/kg-mol
Annual Firing Rate (Waste Gas)	18,148	MMBtu/yr
Annual Firing Rate (Waste Gas)	71.8	MMscf/yr

Maintenance / Startup / Shutdown Flare Gas (MSS)

30,870 lb/hr
385.16 scf/lb-mol
4 Hours per Startup / Shutdown
8 # Startups / Shutdowns per year

Typical Waste Gas Flow Rate	0.58	MMscf/hr
Average Molecular Weight	20.38	kg/kg-mol
Average Fuel HHV	253.20	Btu/scf
Molar Volume Conversion Factor	849.5	scf/kg-mol
Annual Firing Rate (Waste Gas)	4,726	MMBtu/yr
Annual Firing Rate (Waste Gas)	18.7	MMscf/yr

Supplemental Fuel (Natural Gas)

Average Molecular Weight	16.82	kg/kg-mol
Average Fuel HHV	1020.00	Btu/scf
Molar Volume Conversion Factor	849.5	scf/kg-mol
Annual Firing Rate	1,459	MMBtu/yr
Annual Firing Rate	1.4	MMscf/yr

Carbon Content of Ammonia Unit Purge Gas (Normal Operations)

Constituent i	Higher Heating Value, (Btu/scf)	Mol Wt i	Typical Weight %	Weight Frac	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2	325	18	51.2383	0.51238324	59.290	0	0	0
N2	0	28.01	38.6695	0.38669518	28.140	0	0	0
NH3	400	17.03	8.2631	0.0826309	9.890	0	0	0
Argon	0	39.95	1.3132	0.01313177	0.670	0	0	0
CH4	1013	16.04	1.5817	0.01581729	2.010	1	12.01	0.748753
		20.82855						

Carbon Content	0.015	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100	
CH4 Fraction	1.00	Kg C from methane /Kg C in Fuel)	
Stream HHV	252.6138	Higher Heating Value, Btu/scf	

Carbon Content of Maintenance / Startup / Shutdown Flare Gas (MSS)

Constituent i	Higher Heating Value, (Btu/scf)	Mol Wt i	Typical Weight %	Weight Frac	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2	325	18	62.8935	0.62893538	71.220	0	0	0
N2	0	28.01	32.5956	0.32595628	23.720	0	0	0
NH3	400	17.03	3.6511	0.03651133	4.370	0	0	0
Argon	0	39.95	0.5292	0.00529191	0.270	0	0	0
CH4	1013	16.04	0.3305	0.0033051	0.420	1	12.01	0.748753
		20.383016						

Carbon Content	0.003	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100	
CH4 Fraction	1.00	Kg C from methane /Kg C in Fuel)	
Stream HHV	253.1996	Higher Heating Value, Btu/scf	

Carbon Content of Supplemental Natural Gas (MSS)

Constituent i	Mol Wt i	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2	2.016	0.000	0	0.00	0.00
CO	28.01	0.000	1	12.01	0.43
CO2	44.01	1.189	1	12.01	0.27
N2	28.01	0.229	0	0.00	0.00
CH4	16.04	96.189	1	12.01	0.75
ETHANE	30.07	2.037	2	24.02	0.80
PROPANE	44.11	0.219	3	36.03	0.82
N-BUTANE	58.13	0.037	4	48.04	0.83
I-BUTANE	58.13	0.038	4	48.04	0.83
N-PENTANE	72.15	0.008	5	60.05	0.83
I-PENTANE	72.15	0.013	5	60.05	0.83
HEXANES+	86.18	0.041	6	72.06	0.84
H2O	18.02	0.000	0	0.00	0.00
Carbon Content	0.743	kg C/kg fuel (= Σ Carbon Fractioni*Mol%i) / 100			
CH4 Fraction	0.970	Kg C from methane /Kg C in Fuel)			
Stream HHV	1020	Higher Heating Value, Btu/scf			

EMISSION CALCULATIONS

CO2 Emissions

104.07 MMscf/yr, $FLARE_{norm}$ (Pilot Gas)
1020.00 HHV (Nat Gas, MMBtu/MMscf)

60 Kg/MMBtu, EmF
71,842,838.68 scf/yr, $FLARE_{norm}$ (Ammonia Unit Purge Gas, Normal Operations)
18,666,502.52 scf/yr, FLAREssm (Ammonia Unit Purge Gas, MSS)
1,430,000.00 scf/yr, FLAREssm (Supplemental Natural Gas, MSS)
20.83 Kg/Kg-mol, Avg MW of Ammonia Unit Purge Gas, Normal Operations
20.38 Kg/Kg-mol, Avg MW of Ammonia Unit Purge Gas, MSS
16.82 Kg/Kg-mol, Avg MW of Supplemental Fuel Nat Gas
849.5 scf/Kg-mol, MVC
0.015 CCp of Ammonia Unit Purge Gas, Normal Operations, Kg C / Kg Flare Gas
0.003 CCp of Ammonia Unit Purge Gas, MSS, Kg C / Kg Flare Gas
0.743 CCp of Supplemental Nat Gas., Kg C / Kg Flare Gas

6,418 MT/YR, CO2 Emissions (Eqn Y-3, 40 CFR Part 98)
7,074 Ton/yr, CO2

CH4 Emissions

0.003 EmFch4, Emission factor from Table C-2 (40 CFR Part 98)
0.97 fch4, Weight fraction of C in waste gas (conservatively use CH4 fraction in natural gas)

46.51 MT/YR, CH4 Emissions (Eqn Y-4, 40 CFR Part 98)
51.3 Ton/yr, CH4

N2O Emissions

0.0006 EmFn2o, Emission factor from Table C-2 (40 CFR Part 98)

0.0642 MT/YR, N2O Emissions (Eqn Y-5, 40 CFR Part 98)
0.07 Ton/yr, N2O

CO2e Emissions

	Global Warming Potential	CO2e, MT/yr	CO2e, ton/yr
CO2	1	6,418	7,074
CH4	21	977	1,077
N2O	310	20	22
		7,414.0	**8,172.6**

TABLE 8
FLARE SYSTEMS

Number from flow diagram: EPN: FL321	Manufacturer & Model No. (if available): TBD

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Maximum
Ammonia Plant Purge Gas		lb/hr	lb/hr	lb/hr (MSS)
	H2	0	228	19,416
	N2	0	168	10,063
	NH3	0	36	1,128
	Argon	0	6	164
	CH4	0	7	103
% of time this condition occurs		0	~99	~1

	Flow Rate (scfm [68°F, 14.7 psia])		Temperature °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	0	~10,000		
Fuel Added to Gas Stream	0	~2,350		

Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
3	Natural Gas	1.1

For Stream Injection	Stream Pressure (psig)		Total Stream Flow	Temperature °F	Velocity (ft/sec)
	Min. Expected	Design Max.	Rate (lb/hr)		

	Number of Jet Streams	Diameter of Steam Jets (inches)	Design basis for steam injected (lb steam/lb hydrocarbon)

For Water Injection	Water Pressure (psig) Min. Expected Design Max.	Total Water Flow Rate (gpm) Min. Expected Design Max.	No. of Water Jets	Diameter of Water Jets (inches)

Flare Height (ft): 200	Flare tip inside diameter (ft): 3.5
Capital Installed Cost $________	Annual Operating Cost $____________

Supply an assembly drawing, dimensioned and to scale, to show clearly the operation of the flare system. Show interior dimensions and features of the equipment necessary to calculate its performance. Also describe the type of ignition system and its method of operation. Provide an explanation of the control system for steam flow rate and other operating variables.

4.5 Reformer MSS Flare (EPN: FL42)

The primary reformers have previously vented to atmosphere during MSS operations. These emissions are being routed to a flare as BACT for this MSS source. During MSS operations, process gases consisting of carbon monoxide, methane, hydrogen, nitrogen and water must be slowly introduced into or taken out of the synthesis gas compressor. This slow loading of the compressor during MSS results in the need for this vent. The vent is also needed during malfunctions to prevent equipment damage. No upset / malfunction emissions are being permitted in this application. OCI is permitting MSS emissions for this source only. The flare emissions are calculated below.

BASES AND ASSUMPTIONS:

Pilot Gas Combustion:

Fuel Usage: 65 scf/hr-pilot
Number of Pilots: 4 pilots
Typical Nat Gas Heating value: 1,020 Btu/scf
Annual Operating Hours: 8,760 hrs/yr

MSS Operations

Methanol Plant Startups and Shutdowns

- Process Gas can be vented downstream of the reformers (hot vent) or just upstream of the suction of the synthesis gas compressor. The only difference in the vent streams is the amount of water present in the vent stream; therefore, the emissions are essentially identical. For the purposes of calculating the emissions and demonstrating compliance with 40 CFR 60.18, the emissions are based on venting the hot vent.
- Waste gas to flare (including water) = 577,038 lb/hr = 19,646,580.2 scf (68 deg. F and 14.7 psia)
- 4 methanol plant startups and shutdowns / yr
- 8 hours per startup event
- 4 hours per shutdown event

CO_2:

CO_2 emissions are calculated utilizing the following equation:

$$CO_2 = 0.98 \times 0.001 \times \left(Flare_{Norm} \times HHV \times EmF + \sum\left[\frac{44}{12} \times (Flare_{ssm}) \times \frac{MW}{MVC} \times CC\right]\right)$$ (Equation Y-3, 40 CFR Part 98.253)

Where:

CO_2 = Carbon dioxide emissions in metric tons per year;
0.98 = Assumed combustion efficiency of the flare;
0.001 = Conversion factor from Kg to metric tons;
$Flare_{Norm}$ = Annual volume of flare gas combusted during normal operations (Pilot Gas), MMscf/yr;
HHV = Higher heating value for fuel gas or flare gas, MMBtu/MMscf;
EmF = Default CO_2 emission factor for flare gas, 60 Kg CO_2 / MMBtu (high heat basis);
44 = molecular weight of CO_2, Kg/Kg-mol;
12 = atomic weight of C, Kg/Kg-mol;
$Flare_{ssm}$ = Volume of gas combusted during start-up or shutdown event from engineering calculations, scf/event;
MW = Average molecular weight of the flare gas from engineering calculations for each event, kg/kg-mol,
MVC = Molar conversion factor, 849.5 scf/Kg-mol (@ 68°F);
CC = Average carbon content of the flare gas from engineering calculations for each event, Kg C / Kg flare gas;

CH_4:

CH_4 emissions are calculated utilizing the following equation:

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH_4}}{EmF}\right) + CO_2 \times \frac{0.02}{98} \times \frac{16}{44} \times f_{CH_4}$$ (Equation Y-4, 40 CFR Part 98.253)

Where:

CH_4 = Annual methane emissions from flared gas, MT CH_4/yr;
CO_2 = Carbon dioxide emissions from equation Y-3 above, MT/yr;
EmF_{CH4} = Default CH_4 emission factor for "Petroleum Products" from Table C-2 of Subpart C, Kg CH_4 / MMBtu;
EmF = Default CO_2 emission factor for flare gas, 60 Kg CO_2 / MMBtu (high heat basis);
0.02/0.98 = Correction factor for flare combustion efficiency;

16/44 = Correction factor ratio of the molecular weight of CH_4 to CO_2;

f_{CH4} = Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from engineering calculations, Kg C from methane / Kg C in flare gas;

N_2O:

N_2O emissions are calculated utilizing the following equation:

$N_2O = \left(CO_2 \times \frac{EmF_{N2O}}{EmF}\right)$ (Equation Y-6, 40 CFR Part 98.253)

Where: N_2O = Annual nitrous oxide emissions from flared gas, MT N_2O/yr;

CO_2 = Carbon dioxide emissions from equation Y-3 above, MT/yr;

EmF_{N2O} = Default N_2O emission factor for "Petroleum Products" from Table C-2 of Subpart C, Kg N_2O / MMBtu;

EmF = Default CO_2 emission factor for flare gas, 60 Kg CO_2 / MMBtu (high heat basis);

The following table summarizes the greenhouse gas emissions for the Reformer MSS Flare. TCEQ Table 8 and detailed emissions calculations for the flare are included on the following pages.

	EPN: FL42
CO_2 (tpy)	11,637
CH_4 (tpy)	13.6
N_2O (tpy)	0.1

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Reformer MSS Flare GHG Emissions (EPN: FL42)

Pilots

65 Pilot Gas Flow, scfh per pilot
4 # of pilots
15600 Total Pilot Gas Flow, scf/hr
136.66 Total Pilot Gas Flow, MMscf/yr

Waste Gas

577,038 lb/hr
385.16 scf/lb-mol
8 Hours per Startup
4 # Startups per year
4 Hours per Startup
4 # Startups per year

Typical Waste Gas Flow Rate	19.68776	MMscf/hr
Average Molecular Weight	11.29	kg/kg-mol
Average Fuel HHV	244.34	Btu/scf
Molar Volume Conversion Factor	849.5	scf/kg-mol
Annual Startup / Shutdown Hrs	48	hr/yr
Annual Firing Rate (Waste Gas)	230,900	MMBtu/yr
Annual Firing Rate (Waste Gas)	945	MMscf/yr

CARBON CONTENT of REFORMER VNT-42

Constituent i	Higher Heating Value, (Btu/scf)	Typical Weight Frac	Mol Wt i	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2O	0	0.3483	18.02	21.810	0	0.00	0.00
H2	325	0.1047	2.016	58.620	0	0.00	0.00
CO	322	0.3068	28.01	12.358	1	12.01	0.43
CO2	0	0.2167	44.01	5.556	1	12.01	0.27
N2	0	0.0010	28.01	0.040	0	0.00	0.00
CH4	868	0.0230	16.04	1.616	1	12.01	0.75
			11.29				

Carbon Content	0.080	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100	Waste Gas

Carbon Fraction of Methane, Fch4 (= (Carbon Fraction Methane * Mol % Methane / 100) / Overall Carbon Content)		0.15

CO2 Emissions

136.66 MMscf/yr, $FLARE_{norm}$ (Pilot Gas)
1020.00 HHV (Nat Gas, MMBtu/MMscf)
60 Kg/MMBtu, EmF
945012485.8 scf/yr, FLAREssm (Waste Gas Annual)
7.36 Kg/Kg-mol, Avg MW of Waste Gas
849.5 scf/Kg-mol, MVC
0.080 CCp of Waste Gas, Kg C / Kg Flare Gas

10,557 MT/YR, CO2 Emissions (Eqn Y-3, 40 CFR Part 98)
11,637 Ton/yr, CO2

CH4 Emissions

0.003 EmFch4, Emission factor from Table C-2 (40 CFR Part 98)
0.15 fch4, Weight fraction of C in waste gas from methane

12.34 MT/YR, CH4 Emissions (Eqn Y-4, 40 CFR Part 98) - From Waste Gas)
13.6 Ton/yr, CH4

N2O Emissions

0.0006 EmFn2o, Emission factor from Table C-2 (40 CFR Part 98)

0.1056 MT/YR, N2O Emissions (Eqn Y-5, 40 CFR Part 98)
0.1 Ton/yr, N2O

CO2e Emissions

	Global Warming Potential	CO2e, MT/yr	CO2e, ton/yr
CO2	1	10,557	11,637
CH4	21	259	286
N2O	310	33	36
		10,848.5	**11,958.4**

TABLE 8

FLARE SYSTEMS

Number from flow diagram: EPN: FL42			Manufacturer & Model No. (if available): Zeeco Flare Systems	
CHARACTERISTICS OF INPUT				
Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Maximum
		lb/hr	lb/hr	lb/hr
Process Gas	1. CO		177,020	
	2. CO2		125,039	
	3. H2		60,147	
	4. CH4		13,254	
	5. N2		596	
	6. H2O		200,982	
	7			
	8			
% of time this condition occurs		Varies	Varies	Varies

	Flow Rate (scfm [68°F, 14.7 psia])		Temperature °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	0	577,038	630	6
Fuel Added to Gas Stream				

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
	4	Natural Gas	~0.3

For Stream Injection NA	Stream Pressure (psig)		Total Stream Flow Rate (lb/hr)	Temperature °F	Velocity (ft/sec)
	Min. Expected	Design Max.			
	Number of Jet Streams		Diameter of Steam Jets (inches)	Design basis for steam injected (lb steam/lb hydrocarbon)	

For Water Injection NA	Water Pressure (psig) Min. Expected Design Max.	Total Water Flow Rate (gpm) Min. Expected Design Max.	No. of Water Jets	Diameter of Water Jets (inches)

Flare Height (ft): 215	Flare tip inside diameter (ft): 3.5
Capital Installed Cost $ TBD	Annual Operating Cost $ TBD

Supply an assembly drawing, dimensioned and to scale, to show clearly the operation of the flare system. Show interior dimensions and features of the equipment necessary to calculate its performance. Also describe the type of ignition system and its method of operation. Provide an explanation of the control system for steam flow rate and other operating variables.

4.6 Marine Vapor Control System Flare (EPN: 326)

OCI operates a Marine Vapor Control System (MVCS) flare at the marine transfer dock to control methanol vapors displaced during transfer operations. This marine loading operation complies with 40 CFR 63 Subpart Y. The flare is used in conjunction with a Dock Safety Unit (DSU). The DSU enriches the vapors displaced from the marine vessel with natural gas to a safe composition and also helps protect the vessel and system from detonation, excessive pressure, and excessive vacuum.

Emissions for this flare are calculated per the methods in 40 CFR Part 98, Subpart Y. The basis for the emission calculations is defined as follows:

<u>Pilot Gas Basis</u>

Basis & Assumptions:

Fuel Usage: 60 scf/hr-pilot
Number of Pilots: 1 pilot
Annual Operating Hours: 8,760 hrs/yr

<u>Waste Gas Combustion Emissions</u>
Waste gas routed to the flare occurs as the barge is being loaded. There is a minimum, average, and maximum loading case (the loading cycle) that occurs during the loading of each marine vessel.

<u>Minimum Loading Case</u>

Gas flow = 66 scfm or 3,960 scfh of natural gas;
Hours per year = 115 hr/yr;

<u>Average Loading Case</u>

Gas flow = 566 scfm or 33,960 scfh of natural gas;
Methanol flow = 41 scfm or 2,460 scfh;
Hours per year = 2005 hr/yr

<u>Maximum Loading Case</u>

Gas flow = 280 scfm or 16,800 scfh of natural gas;
Methanol flow = 169 scfm or 10,140 scfh;
Hours per year = 115 hr/yr;

CO_2:

CO_2 emissions are calculated utilizing the following equation:

$$CO_2 = 0.98 \times 0.001 \times \left(Flare_{Norm} \times HHV \times EmF + \sum \left[\frac{44}{12} \times (Flare_{Cases}) \times \frac{MW}{MVC} \times CC \right] \right)$$ (Equation Y-3, 40 CFR Part 98.253)

Where:

CO_2 = Carbon dioxide emissions in metric tons per year;
0.98 = Assumed combustion efficiency of the flare;
0.001 = Conversion factor from Kg to metric tons;
$Flare_{Norm}$ = Annual volume of flare gas combusted during normal operations (Pilot Gas), MMscf/yr;
HHV = Higher heating value for fuel gas or flare gas, MMBtu/MMscf;
EmF = Default CO_2 emission factor for flare gas, 60 Kg CO_2 / MMBtu (high heat basis);
44 = molecular weight of CO_2, Kg/Kg-mol;
12 = atomic weight of C, Kg/Kg-mol;
$Flare_{Cases}$ = Volume of gas combusted during each loading event from engineering calculations, scf/event;
MW = Average molecular weight of the flare gas from engineering calculations for each event, kg/kg-mol,
MVC = Molar conversion factor, 849.5 scf/Kg-mol (@ 68°F);
CC = Average carbon content of the flare gas from engineering calculations for each event, Kg C / Kg flare gas;

CH_4:

CH_4 emissions are calculated utilizing the following equation:

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH_4}}{EmF} \right) + CO_2 \times \frac{0.02}{98} \times \frac{16}{44} \times f_{CH_4}$$ (Equation Y-4, 40 CFR Part 98.253)

Where:

CH_4 = Annual methane emissions from flared gas, MT CH_4/yr;
CO_2 = Carbon dioxide emissions from equation Y-3 above, MT/yr;
EmF_{CH4} = Default CH_4 emission factor for "Petroleum Products" from Table C-2 of Subpart C, Kg CH_4 / MMBtu;
EmF = Default CO_2 emission factor for flare gas, 60 Kg CO_2 / MMBtu (high heat basis);
0.02/0.98 = Correction factor for flare combustion efficiency;

16/44 = Correction factor ratio of the molecular weight of CH_4 to CO_2;
f_{CH4} = Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from engineering calculations, Kg C from methane / Kg C in flare gas;
Note: f_{CH4} utilized for the purposes of calculating emissions is based on the Average Loading Case

N_2O:

N_2O emissions are calculated utilizing the following equation:

$$N_2O = \left(CO_2 \times \frac{EmF_{N2O}}{EmF}\right)$$ (Equation Y-6, 40 CFR Part 98.253)

Where:
N_2O = Annual nitrous oxide emissions from flared gas, MT N_2O/yr;
CO_2 = Carbon dioxide emissions from equation Y-3 above, MT/yr;
EmF_{N2O} = Default N_2O emission factor for "Petroleum Products" from Table C-2 of Subpart C, Kg N_2O / MMBtu;
EmF = Default CO_2 emission factor for flare gas, 60 Kg CO_2 / MMBtu (high heat basis);

The following table summarizes the greenhouse gas emissions for the Marine Vapor Control System Flare. TCEQ Table 8 and detailed emissions calculations for the flare are included on the following pages.

	EPN: 326
CO_2 (tpy)	6,666
CH_4 (tpy)	46.6
N_2O (tpy)	0.07

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Pilots

60	Pilot Gas Flow, scfm per pilot
1	# of pilots
3600	Total Pilot Gas Flow, scf/hr
31.54	Total Pilot Gas Flow, MMscf/yr
1018.34	Average HHV of Nat Gas, MMBtu/MMscf

Loading Vapors Displaced (Methanol)

2,460	scf/hr, Average Case
6.39	lb-mol/hr, Average Case
10,140	scf/hr, Maximum Case
26.33	lb-mol/hr, Maximum Case

Supplemental Fuel (Natural Gas)

3,960	scf/hr, Minimum Case
10.28	lb-mol/hr, Minimum Case
33,960	scf/hr, Average Case
88.17	lb-mol/hr, Average Case
16,800	scf/hr, Maximum Case
43.62	lb-mol/hr, Maximum Case

Loading Cycle Hours

115	Minimum Case
2,005	Average Case
115	Maximum Case

Minimum Case Flare Gas (Natural Gas Only)

Constituent i	Mol Wt i	Mol% i	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2	2.016	0.000	0	0.00	0.00
CO	28.01	0.000	1	12.01	0.43
CO2	44.01	1.189	1	12.01	0.27
N2	28.01	0.229	0	0.00	0.00
CH4	16.04	96.189	1	12.01	0.75
ETHANE	30.07	2.037	2	24.02	0.80
PROPANE	44.11	0.219	3	36.03	0.82
N-BUTANE	58.13	0.037	4	48.04	0.83
I-BUTANE	58.13	0.038	4	48.04	0.83
N-PENTANE	72.15	0.008	5	60.05	0.83
I-PENTANE	72.15	0.013	5	60.05	0.83
HEXANES+	86.18	0.041	6	72.06	0.84
H2O	18.02	0.000	0	0.00	0.00
	16.82				

Carbon Content	0.743	kg C/kg fuel (= Σ Carbon $Fraction_i$*$Mol\%_i$) / 100
CH4 Fraction	0.970	Kg C from methane /Kg C in Fuel)

Average Case Flare Gas (Natural Gas + MeOH)

Constituent i	Mol Wt i	Mol% I (Nat Gas)	Mol% (Methanol)	# lb Moles i	Mol% I (Combined Stream)	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2	2.016	0.000		-	0.000	0	0.00	0.00
CO	28.01	0.000		-	0.000	1	12.01	0.43
CO2	44.01	1.189		1.048	1.109	1	12.01	0.27
N2	28.01	0.229		0.202	0.213	0	0.00	0.00
CH4	16.04	96.189		84.811	89.692	1	12.01	0.75
ETHANE	30.07	2.037		1.796	1.899	2	24.02	0.80
PROPANE	44.11	0.219		0.193	0.204	3	36.03	0.82
N-BUTANE	58.13	0.037		0.033	0.035	4	48.04	0.83
I-BUTANE	58.13	0.038		0.034	0.036	4	48.04	0.83
N-PENTANE	72.15	0.008		0.007	0.008	5	60.05	0.83
I-PENTANE	72.15	0.013		0.011	0.012	5	60.05	0.83
HEXANES+	86.18	0.041		0.036	0.038	6	72.06	0.84
H2O	18.02	0.000		-	0.000	0	0.00	0.00
CH3OH	32		100	6.39	6.755	1	12.01	0.38
	17.84			94.558				

Carbon Content	0.718	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100
CH4 Fraction	0.936	Kg C from methane /Kg C in Fuel)

Maximum Case Flare Gas (Natural Gas + MeOH)

Constituent i	Mol Wt i	Mol% I (Nat Gas)	Mol% (Methanol)	# lb Moles i	Mol% I (Combined Stream)	No. Of Carbon Atoms	Carbon (= 12.01* No. C)	Carbon Fraction (= Carbon / Mol Wt)
H2	2.016	0.000		-	0.000	0	0.00	0.00
CO	28.01	0.000		-	0.000	1	12.01	0.43
CO2	44.01	1.189		1.048	0.916	1	12.01	0.27
N2	28.01	0.229		0.202	0.176	0	0.00	0.00
CH4	16.04	96.189		84.811	74.072	1	12.01	0.75
ETHANE	30.07	2.037		1.796	1.568	2	24.02	0.80
PROPANE	44.11	0.219		0.193	0.169	3	36.03	0.82
N-BUTANE	58.13	0.037		0.033	0.029	4	48.04	0.83
I-BUTANE	58.13	0.038		0.034	0.029	4	48.04	0.83
N-PENTANE	72.15	0.008		0.007	0.006	5	60.05	0.83
I-PENTANE	72.15	0.013		0.011	0.010	5	60.05	0.83
HEXANES+	86.18	0.041		0.036	0.031	6	72.06	0.84
H2O	18.02	0.000		-	0.000	0	0.00	0.00
CH3OH	32		100	26.33	22.993	1	12.01	0.38
	20.31			114.498				

Carbon Content	0.658	kg C/kg fuel (= Σ Carbon Fraction$_i$*Mol%$_i$) / 100
CH4 Fraction	0.843	Kg C from methane /Kg C in Fuel)

CO_2 Emissions

31.54 MMscf/yr, $FLARE_{norm}$ (Pilot Gas)
1020.00 HHV (Nat Gas, MMBtu/MMscf)
60 Kg/MMBtu, EmF
456,194 scf/yr, FLAREmin (Minimum Loading Case Flare Gas Annual)
73,022,100 scf/yr, FLAREavg (Average Loading Case Flare Gas Annual)
3,098,100 scf/yr, FLAREmax (Maximum Loading Case Flare Gas Annual)
16.82 Kg/Kg-mol, Avg MW of Minimum Case
17.84 Kg/Kg-mol, Avg MW of Average Case
20.31 Kg/Kg-mol, Avg MW of Maximum Case
849.5 scf/Kg-mol, MVC
0.743 CCp of Minimum Case, Kg C / Kg Flare Gas
0.718 CCp of Average Case, Kg C / Kg Flare Gas
0.658 CCp of Maximum Case, Kg C / Kg Flare Gas

6,047 MT/YR, CO_2 Emissions (Eqn Y-3, 40 CFR Part 98)
6,666 Ton/yr, CO_2

CH_4 Emissions

0.003 EmFch4, Emission factor from Table C-2 (40 CFR Part 98)
0.94 fch4, Weight fraction of C in waste gas from Average Case

42.29 MT/YR, CH_4 Emissions (Eqn Y-4, 40 CFR Part 98) - From Waste Gas)
46.6 Ton/yr, CH_4

N_2O Emissions

0.0006 EmFn2o, Emission factor from Table C-2 (40 CFR Part 98)

0.0605 MT/YR, N_2O Emissions (Eqn Y-5, 40 CFR Part 98)
0.07 Ton/yr, N_2O

CO_2e Emissions

	Global Warming Potential	CO2e, MT/yr	CO2e, ton/yr
CO2	1	6,047	6,666
CH4	21	888	979
N2O	310	19	21
		6,954.2	**7,665.7**

TABLE 8

FLARE SYSTEMS

Number from flow diagram: EPN: 326	Manufacturer & Model No. (if available): Zink Elevated Flare

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Maximum
		lb/hr	lb/hr	lb/hr
	1. Methanol	0	41	169
	2. Air	54	498	369
	3. Natural Gas	66	566	280
	4			
	5			
	6			
	7			
	8			
	9			
	10			
	11			
	12			
	13			
	14			
	15			
	16			
	17			
% of time this condition occurs		~5	~90	~5

	Flow Rate (scfm [68°F, 14.7 psia])		Temperature °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	120	1200	30-100	-0.1-0.2
Fuel Added to Gas Stream				

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
	1	Natural Gas	~1

For Stream Injection	Stream Pressure (psig)		Total Stream Flow	Temperature °F	Velocity (ft/sec)
	Min. Expected	Design Max.	Rate (lb/hr)		

For Stream Injection	Number of Jet Streams	Diameter of Steam Jets (inches)	Design basis for steam injected (lb steam/lb hydrocarbon)

For Water Injection	Water Pressure (psig) Min. Expected Design Max.	Total Water Flow Rate (gpm) Min. Expected Design Max.	No. of Water Jets	Diameter of Water Jets (inches)

Flare Height (ft): 35	Flare tip inside diameter (ft): 0.83*
Capital Installed Cost $ 35,000 (approximately)	Annual Operating Cost $ 10,000 (approximately)

Supply an assembly drawing, dimensioned and to scale, to show clearly the operation of the flare system. Show interior dimensions and features of the equipment necessary to calculate its performance. Also describe the type of ignition system and its method of operation. Provide an explanation of the control system for steam flow rate and other operating variables.

* Two 10-inch tips with ~50% open area and 1-inch plugs.

4.7 CO_2 Stripper Vent Maintenance (EPN: MET-STK44)

The CO_2 stripper will no longer be utilized as a continuous process vent during normal operations. After the debottlenecking project is completed, the vent will only operate during maintenance of the Saturator Column, which may occur for up to 240 hr/yr. The CO_2 stripper is designed for a maximum feed rate of 500 gallons per minute of process condensate. This process condensate is stripped with saturated steam. Process engineering calculates that dissolved greenhouse gases in the process condensate are present at the following concentrations:

Methane	0.00063 % by weight
Carbon Dioxide	0.05747 % by weight

The maximum potential emissions from the condensate stripper are as follows:

$$Flow\ Rate = \frac{500\ gal}{min} \times \frac{60\ min}{hr} \times \frac{8.34\ lb}{gal} = 250{,}200\ \frac{lb}{hr}$$

Methane	=	(0.00063/100) x 250,200 = 1.6 lbs/hr
Carbon Dioxide	=	(0.05747/100) x 250,200 = 143.8 lbs/hr

The average annual emissions from the condensate stripper are estimated as follows:

Methane	=	1.6 (lbs/hr) x 240 (hr/yr) / 2000 (lb/ton) = 0.2 tpy
Carbon Dioxide	=	143.8 (lbs/hr) x 240 (hr/yr) / 2000 (lb/ton) = 17.3 tpy

The following table summarizes the post-debottlenecking greenhouse gas emissions associated with the CO_2 Stripper Vent.

	EPN: MET-STK44
CO_2 (tpy)	17.3
CH_4 (tpy)	0.2
N_2O (tpy)	0.0

This represents a net reduction of 209 tons per year of CO_2e from the previous operating mode.

5.0 PSD REVIEW

The project emissions and PSD major modification threshold values are listed in Table 1F and 2F on the following pages.

As shown in both the Table 1F and 2F, emissions from the project exceed the PSD major modification thresholds for GHG's. While there are some contemporaneous decreases in GHG emissions contained in this project, these decreases are not significant when compared to the project increases. PSD review is required for the project emissions. Project increases alone exceed the PSD netting and applicability thresholds significantly. There are no significant creditable decreases of emissions in the contemporaneous period that would change this PSD applicability determination with respect to GHGs.

Table 1F – Air Quality Application Supplement

Table 2F – Project Emission Increase

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: 901	Application Submittal Date: December 2012
Company: OCI Beaumont LLC	
RN: 102559291	Facility Location: 5470 N. Twin City Highway
City: Nederland, TX 77627	County: Jefferson
Permit Unit I.D.: Multiple	Permit Name: Methanol / Ammonia Units
Permit Activity: ☐ New Source ☒ Modification	
Project or Process Description: Reauthorize Reforming Furnaces and Process Debottlenecking	

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS (tons)								
	Ozone		CO	PM	PM_{10}	PM2.5	NO_X	SO_2	Other[1] CO2e (GHG's)
	VOC	NO_X							
Nonattainment? (yes or no)	NO	NO	NO	NO	NO	NO	NO	NO	NA
Existing site PTE (tpy)?	108.7	681.3	637.7	75.95	61.13	21.97	681.3	6.34	1,198,375
Proposed project emission increases (tpy from 2F)[3]	148.4	-465.8	233.8	89.9	89.9	89.9	-465.8	2.1	> 75,000
Is the existing site a major source? [2]If not, is the project a major source by itself? (yes or no)	YES	YES	YES	NO	NO	NO	YES	NO	YES
Significance Level (tpy)	40	40	100	25	15	10	40	40	75,000
If site is major, is project increase significant?	YES	NO	YES	NO	YES	YES	NO	NO	YES
If netting required, estimated start of construction?									
Five years prior to start of construction	contemporaneous								
Estimated start of operation	03/2014 period								
Net contemporaneous change, including proposed project, from Table 3F. (tpy)									
FNSR APPLICABLE? (yes or no)	YES (VOC, CO, PM10, PM2.5, GHG's)								

1 Other PSD pollutants.
2 Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR § 51.166(b)(1).
3 Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR § 51.166(b)(23).

The representations made above and on the accompanying tables are true and correct to the best of my knowledge.

Signature: [signature] Title: General Manager Date: 12/19/12

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]: VOC	Permit: 901
Baseline Period: Jan. 1, 2003	to Dec. 31, 2004

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions [5]	Projected Actual Emissions	Difference (B-A)[6]	Correction[7]	Project Increase[8]
1	RFM41	STK-41	901		6.0	64.11		58.01		58.01
2	MVCS	326	901		0.662	2.74		2.1		2.1
3	TFX-33/34	35	901		11.97	61.62		49.7		49.7
4	PRFMHTR	PRFMHTR	NEW		-	7.59		7.59		7.59
5	MET/TFX46	MET-VRS46	901		0.0919	0		-0.1		-0.1
6	MET/REF48	MET-COM48	901		1.272	0		-1.3		-1.3
7	MET/PRC247	MET-FUG247	901		4.8	5.40		0.6		0.6
8	RFM42	FL42	NEW		-	0.01		0.01		0.01
9	Multiple	45	901		0.552	32.24		31.7		31.7
10										
11										
12										
13										
14										
15										
								Page Subtotal[9]		148.4

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]: NOx	Permit: 901
Baseline Period: Jan. 1, 2003	to Dec. 31, 2004

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions [5]	Projected Actual Emissions	Difference (B-A)[6]	Correction[7]	Project Increase[8]
1	RFM41	STK-41	901		634.70	137.57		-497.1		-497.1
2	MVCS	326	901		1.76	2.32		0.6		0.6
3	PRFMHTR	PRFMHTR	NEW		-	14.76		14.76		14.76
4	Multiple	45	901		1.34	10.67		9.3		9.3
5	RFM42	FL42	NEW		-	6.66		6.66		6.66
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
								Page Subtotal[9]		-465.8

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]: CO	Permit: 901
Baseline Period: Jan. 1, 2002	to Dec. 31, 2003

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions [5]	Projected Actual Emissions	Difference (B-A)[6]	Correction[7]	Project Increase[8]
1	RFM41	STK-41	901		134.3	499.13		364.9		364.9
2	MVCS	326	901		14.86	19.63		4.8		4.8
3	PRFMHTR	PRFMHTR	NEW		-	60.33		60.33		60.33
4	Multiple	45	901		1.144	29.4		28.3		28.3
5	RFM42	FL42	NEW		-	56.45		56.45		56.45
6	RFM42	VNT-42	901		205.86	0		-205.9		-205.9
7	MET/STK44	MET-STK44	901		77.26	2.30		-75		-75
8										
9										
10										
11										
12										
13										
14										
15										
								Page Subtotal[9]		233.8

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]: SO2	Permit: 901
Baseline Period: Jan. 1, 2003	to Dec. 31, 2004

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions [5]	Projected Actual Emissions	Difference (B-A)[6]	Correction[7]	Project Increase[8]
1	RFM41	STK-41	901		4.32	5.59		1.13		1.13
2	PRFMHTR	PRFMHTR	NEW		-	0.83		0.83		0.83
3	RFM42	FL42	NEW		-	0.01		0.01		0.01
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
								Page Subtotal[9]		2.1

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]: PM	Permit: 901
Baseline Period: Jan. 1, 2002	to Dec. 31, 2003

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions [5]	Projected Actual Emissions	Difference (B-A)[6]	Correction[7]	Project Increase[8]
1	RFM41	STK-41	901		9.2	88.59		79.4		79.4
2	PRFMHTR	PRFMHTR	NEW		-	10.50		10.50		10.50
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
								Page Subtotal[9]		89.9

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]: PM10	Permit: 901
Baseline Period: Jan. 1, 2002	to Dec. 31, 2003

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions [5]	Projected Actual Emissions	Difference (B-A)[6]	Correction[7]	Project Increase[8]
1	RFM41	STK-41	901		9.2	88.59		79.4		79.4
2	PRFMHTR	PRFMHTR	NEW		-	10.50		10.50		10.50
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
								Page Subtotal[9]		89.9

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]: PM2.5	Permit: 901
Baseline Period: Jan. 1, 2002	to Dec. 31, 2003

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions [5]	Projected Actual Emissions	Difference (B-A)[6]	Correction[7]	Project Increase[8]
1	RFM41	STK-41	901		9.2	88.59		79.4		79.4
2	PRFMHTR	PRFMHTR	NEW		-	10.50		10.50		10.50
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
								Page Subtotal[9]		89.9

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]: CO2e	Permit: 901
Baseline Period: Jan. 1, 2003	to Dec. 31, 2004

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions [5]	Projected Actual Emissions	Difference (B-A)[6]	Correction[7]	Project Increase[8]
1	RFM41	STK-41	901		948,010	1,265,460		317,450		317,450
2	PRFMHTR	PRFMHTR	NEW		-	165,005		165,005		165,005
3										
4										
5										
6										
7										
10										
11										
12										
13										
14										
15										
								Page Subtotal[9]		> 75,000

The project has some minor increases and decreases, however, PSD applicability is not impacted. The Reformer increases alone trigger PSD Review for GHG's. Baseline emissions for GHG's were not calculated in the past and calculating GHG's for the purposes of PSD applicability will not affect the analysis.

TABLE 2F
PROJECT EMISSION INCREASE

All emissions must be listed in tons per year (tpy). The same baseline period must apply for all facilities for a given NSR pollutant.

1. Individual Table 2F=s should be used to summarize the project emission increase for each criteria pollutant.
2. Emission Point Number as designated in NSR Permit or Emissions Inventory.
3. All records and calculations for these values must be available upon request.
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement.
6. Proposed Emissions (column B) Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number.
9. Sum all values for this page.

Pollutant:		Line		Type (1)	
Explanation:					

1. Type of note. Generally would be baseline adjustment, basis for projected actual, or basis for correction (what could have been accommodated).

6.0 BACT ANALYSIS SUMMARY

OCI has included a BACT analysis in Appendix B for GHG's as applicable. This BACT analysis follows the EPA established a 5-step process for conducting a "top-down" BACT review, as follows:

1) Identification of available control technologies;
2) Technically infeasible alternatives are eliminated from consideration;
3) Remaining control technologies are ranked by control effectiveness;
4) Evaluation of control technologies for cost-effectiveness, energy impacts, and environmental effects in order of most effective control option to least effective; and
5) Selection of BACT.

The top down BACT analysis has been performed for the Steam Reformers and the Pre-Reformer Fired Heater. The remaining sources addressed in this permit were either already routed to a flare or are being routed to a flare to reduce atmospheric emissions of other compounds. A top-down BACT analysis was not performed for these sources since the flares are controlling non-GHG pollutants.

As a result of the BACT analysis, OCI proposes the following BACT for the emission sources in the permit application:

Pollutant	Facility	Proposed BACT
GHG	Steam Reformers	Process energy efficiency improvements including pre-reformer and saturator column
GHG	Pre-Reformer Fired Heater	Energy Efficient Process Heater

DISTRIBUTION

OCI Beaumont LLC
Beaumont Plant
TCEQ Permit No. 901 Amendment

December 2012

Copy 1-2: OCI Beaumont LLC
PO Box 1647
Nederland, TX 77627

Copy 3: U.S. EPA Region 6
Air Permits Section (PD-R)
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

Copy 4: TCEQ
Air Permits Initial Review Team (MC-161)
P.O. Box 13087
Austin, TX 78711-3087

Copy 5: Kathryn Sauceda, Air Section Manager
TCEQ Region 10
3870 Eastex Fwy.
Beaumont, TX 77703-1830

Copy 6: Wolf Environmental LLC
PO Box 1483
Friendswood, Texas 77549

QA/QC Review

DWParrish

Dan W. Parrish
Air Program Manager

APPENDIX A – ACRONYM LIST

The following abbreviations or acronyms may be used in this permit application:

acf	actual cubic feet
acfm	actual cubic feet per minute
BACT	Best available control technology
Btu	British thermal unit(s)
°C	degrees Celsius
CC/AFRC	combustion catalyst/air-fuel ratio controller
CH_4	methane
CIN	control identification number
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
dscf	dry standard cubic feet
EPA	Environmental Protection Agency
EPN	emission point number
ESL	effects screening level
°F	degrees Fahrenheit
FIN	facility identification number
ft	feet
ft^3	cubic feet
g	gram(s)
gal	gallon(s)
GHG	Greenhouse gas(es)
GOP	General Operating Permit
gr	grain(s)
H_2	hydrogen
H_2S	hydrogen sulfide
HAP	hazardous air pollutant
hp	horsepower
hr	hour(s)
in	inch(es)
K	kelvin
lb	pounds(s)
m	meter(s)
m^3	cubic meter(s)
min	minute(s)
M	thousand
MACT	Maximum achievable control technology (40 CFR Part 63
MAERT	maximum allowable emission rate table
MM	million

MTPD	metric tons per day
N_2	nitrogen
N_2O	dinitrogen oxide
NA	not applicable
NESHAP	National Emission Standard for Hazardous Air Pollutants
NO_x	nitrogen oxides
NSPS	New Source Performance Standard (40 CFR Part 60)
NSR	New Source Review
PBR	Permit(s) by Rule
PM	particulate matter
PM_{10}	particulate matter with the mean aerodynamic diameter of 10 microns or less
$PM_{2.5}$	particulate matter with mean aerodynamic diameter of 2.5 microns or less
ppmv	parts per million by volume
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
psig	pounds square inch gauge
PTE	potential to emit
RACT	reasonably available control technology
R	Rankine
s	second(s)
scf	standard cubic feet
SIP	State Implementation Plan
SOCMI HON	Synthetic Organic Chemical Manufacturing Industry Hazardous Organic Neshap (40 CFR Part 63, Subparts F, G, H)
SOP	Standard Operating Permit
SO_2	sulfur dioxide
TAC	Texas Administrative Code
TBD	to be determined
THC	total hydrocarbon
TCEQ	Texas Commission on Environmental Quality
TOC	total organic compound
tonne	metric ton
tpd	ton(s) per day
tpy	ton(s) per year
TSP	total suspended particulate
USEPA (EPA)	United States Environmental Protection Agency
USGS	United States Geological Survey
VOHAP	volatile organic hazardous air pollutant
VOC	volatile organic compound
VOL	volatile organic liquid
yr	year(s)

Revised: 04.21.11:tr

APPENDIX B – BACT ANALYSIS

STEAM METHANE REFORMERS

Step 1 – Identification of Available Control Technologies

Greenhouse Gases

The following potential control technologies have been identified for the control of GHG's from the reformer furnaces:

- Carbon Capture and Storage (CCS) (only CO_2)
  - Post-Combustion CCS involves the capture, separation, transport, and geologic storage of CO_2 emitted from the reformer flue gas. As an alternative to storage, CO_2 also has several beneficial uses such as enhanced oil recovery and uses in the food industry. Capture rates of CO_2 can be as high as 90%.
- Heat Recovery
  - Heat energy resulting from the combustion of fuel in the reformers is used as a heat source within the process and for various utility duties. This use of heat energy reduces the energy consumed by the overall process by utilizing the waste heat instead of operating additional process equipment such as heaters and boilers to generate heat and steam. The direct result of reducing the need for process heaters / boilers is reduced use of fossil fuels and thus lower emissions of GHG's. The current process configuration utilizes heat recovery to greatly reduce the need for additional heaters / boilers for steam production, feedstock preheating, boiler water preheating, and other process heat needs.
- Improved Combustion Measures
  - Periodic Tuning: Periodic tuning serves to maximize combustion efficiency by reducing CO and unburned carbon, thus reducing GHG emissions.
  - Instrumentation and Controls: Installation of modern instrumentation and controls is a viable method of improving efficiency and reducing greenhouse gas emissions.
  - Proper/Efficient Operation: Operation of the reformers per design specifications and operating parameters increase efficiency and reduce fouling of heat transfer surfaces.
- Maintenance Practices/Operational Monitoring
  - Insulation: Maintaining proper insulation increases reformer efficiency and reduces fuel use which directly reduces emissions of GHG's

- Minimization of Air Infiltration: Minimization of unwanted air infiltration into the reformers results in increased efficiency of operation which minimizes fuel use.

- Improve Process Energy Efficiency
  - The existing reformer tubes could be replaced with tubes that are larger in diameter and that have a smaller wall thickness. These tubes would contain more catalyst than the existing tubes, resulting in increased production efficiency. The smaller wall thickness would result in increased heat transfer, which would in turn decrease the amount of heat input that is currently required to process equivalent amounts of synthesis gas in the reformers.
  - A saturator column could be added to the process. Addition of the saturator column would serve to increase process efficiency by recovering and recycling two waste streams. The dehydrator tails and stripper tails streams would be recycled as process feedstocks. The saturator column operates by counter currently contacting natural gas feedstock with organic-containing distillation bottoms. The organics contained in the water is vaporized and transferred into the natural gas feedstock stream. Steam is also generated in the column and is fed to the reformers along with the feedstock. Process efficiency improvements are realized because the amount of feedstock natural gas is reduced due to the use of the recovered organics. In addition, reduced steam demand increases process efficiency by way of reduced heat input requirements needed to create the steam in the current process configuration. The saturator column would also serve to eliminate the atmospheric CO_2 stripper emission point in the current process by processing the vent stream through the saturator column, reducing CO_2 emissions by 612.6 tpy and methane emissions by 6.8 tpy.
  - Addition of a pre-reformer that converts hydrocarbons heavier than methane into methane prior to entering the steam reformers. The benefit of the pre-reformer is a reduction in required heat input for the steam reformers.

Step 2 - Elimination of Technically Infeasible Technologies

<u>Greenhouse Gases</u>

- Carbon Capture and Storage (CCS) (only CO_2)

  - While CCS may one day be a viable large-scale control technology for CO_2, it is not currently available for large-scale deployment. Several different CCS technologies have demonstrated the potential to become viable post-combustion add-on control technologies; however, several have only been validated at the laboratory scale, while others have been confirmed to be effective at the slip-stream or pilot-scale. Per the Interagency Task Force on Carbon Capture, current technologies could be used to capture CO_2 from new and existing plants, they are not ready for widespread implementation and "widespread cost-effective deployment of CCS will occur only if the technology is commercially available and a supportive national policy framework is in place"[2].

- The goal of CCS is to capture, concentrate, and store highly concentrated, pure CO_2. Application of CCS to large industrial natural gas-fired combustion devices, such as the OCI reformers, is not currently economically feasible due to the following characteristics of the flue gas stream:
    - Low CO_2 concentration
    - Low pressure
    - High Temperature
    - High Volume

- These flue gas characteristics require extensive treatment processes, including separation, cooling, and pressurization prior to transporting the CO_2 to the geologic storage location. These processes are energy intensive and presently very expensive. The process would generate additional greenhouse gases.

- The Interagency Task Force on Carbon Capture concluded that the avoided cost ($/tonne) to retrofit an existing power plant with post-combustion CCS technology is about $103/tonne or $93.64/ton (includes initial investment, operations and maintenance, cost of fuel, and cost of capital). Assuming approximately 90% control of CO_2, the approximate cost to install, operate, and maintain the equipment of CCS for the reformers is in excess of $106.2 million per year, which is not a cost effective option for the control of CO_2. For the purposes of this assessment, the cost of transportation and storage are not evaluated since the cost for CCS is prohibitive even neglecting transport and storage.

- Heat Recovery

    - The existing process unit uses heat recovery technology to the maximum extent possible. No additional heat recovery options have been identified by the engineering team

Step 3 – Ranking of Remaining Control Technologies by Effectiveness

Greenhouse Gases

The remaining technologies in order of most effective to least effective in reducing CO_2 emissions are included below:

1. Improve reformer / process energy efficiency by installing new / better technologies (~15%)
2. Improved Combustion Measures (up to ~11%)
    - Proper/Efficient Operation (up to ~4%)[3]
    - Instrumentation and Controls (up to ~4%)[3]
    - Tuning (up to ~3%)[3]
3. Maintenance Practices/Operational Monitoring (up to ~11%)
    - Insulation (up to ~7%)[3]
    - Minimization of Air Infiltration (up to ~ 4%)[3]

4 - Evaluation of Control Technologies in Order of Most Effective Control Option to Least Effective

Greenhouse Gases

Process efficiency improvements – The approximate cost of the proposed improvements to the process is approximately $83 million dollars. The reformer improvements, addition of the pre-reformer, and addition of the saturator column are considered reasonable to improve the energy efficiency of the unit. The remaining control measures for reducing greenhouse gases include improved energy efficiency, and maintenance practices/operational monitoring. These measures are already inherent to the design of the reformers. Ongoing maintenance (periodic tuning, minimization of air infiltration, insulation maintenance, and minimization of air filtration) and operational best practices (utilization of instrumentation/controls and efficient operation) will continue to be utilized in order to minimize greenhouse gas emissions.

5 - Selection of BACT

Greenhouse Gases

OCI proposes the addition of a pre-reformer, saturator column, and reformer tube replacement as BACT for these reformers and the methanol production process. OCI will continue to utilize existing heat recovery equipment in order to maximize energy efficiency of the process. In addition, OCI will utilize improved combustion measures and proper maintenance/operational monitoring to minimize greenhouse gas emissions. The emission limit of each of the greenhouse gases and CO_2e are as follows:

	tpy
CO_2	1,260,266.9
CH_4	62.6
N_2O	12.5
CO_2e	1,265,459.6

PRE-REFORMER FIRED HEATER

Step 1 – Identification of Available Control Technologies

Greenhouse Gases

The following potential control technologies have been identified for the control of GHG's from the pre-reformer fired heater:

- Carbon Capture and Storage (CCS) (only CO_2)
    - Post-Combustion CCS involves the capture, separation, transport, and geologic storage of CO_2 emitted from the reformer flue gas. As an alternative to storage, CO_2 also has several beneficial uses such as enhanced oil recovery and uses in the food industry. Capture rates of CO_2 can be as high as 90%.
- Heat Recovery
    - Waste heat recovery from the flue gas is a desirable energy efficiency option. Use of heat in the flue gas will reduce the need for additional fossil fuel firing by passing the primary reformer feed through a waste heat recovery heat exchanger in order to heat the primary reformer feed to the required temperature, thus reducing the overall energy requirements for the process. The proposed project will utilize recovery of the waste heat in the flue gas of the pre-reformer fired heater.
- Efficient Combustion Measures
    - Periodic Tuning: Periodic tuning serves to maximize combustion efficiency by reducing CO and unburned carbon, thus reducing GHG emissions.
    - Instrumentation and Controls: Installation of modern instrumentation and controls is a viable method of improving efficiency and reducing GHG emissions.
    - Proper/Efficient Operation: Operation of the reformers per design specifications and operating parameters increase efficiency and reduce fouling of heat transfer surfaces.
- Maintenance Practices/Operational Monitoring
    - Insulation: Maintaining proper insulation increases efficiency and reduces fuel use which directly reduces emissions of GHG's.
    - Minimization of Air Infiltration: Minimization of unwanted air infiltration into the heater results in increased efficiency of operation which minimizes fuel use.

Step 2 - Elimination of Technically Infeasible Technologies

Greenhouse Gases

- Carbon Capture and Storage (CCS) (only CO_2)
  - As discussed in the BACT analysis for the steam reformers, CCS may one day be a viable large-scale control technology for CO_2, it is not currently available for large-scale deployment and the costs associated with CCS are cost prohibitive.

Step 3 – Ranking of Remaining Control Technologies by Effectiveness

Greenhouse Gases

The remaining technologies not in order of most effective to least effective in reducing CO_2 emissions are included below:

1. Efficient Combustion Measures (up to ~11%)
   - Proper/Efficient Operation (up to ~4%)[3]
   - Instrumentation and Controls (up to ~4%)[3]
   - Tuning (up to ~3%)[3]

2. Maintenance Practices/Operational Monitoring (up to ~11%)
   a. Insulation (up to ~7%)[3]
   b. Minimization of Air Infiltration (up to ~ 4%)[3]

4 - Evaluation of Control Technologies in Order of Most Effective Control Option to Least Effective

Greenhouse Gases

Efficient combustion measures, routine maintenance practices / operational monitoring, and heat recovery from the fired heater flue gas are approximately equivalent in effectiveness in reducing CO_2 emissions. All of the control measures will be performed on the Pre-Reformer Fired Heater.

5 - Selection of BACT

Greenhouse Gases

OCI proposes the use of efficient combustion measures, routine maintenance practices / operational monitoring, and heat recovery from the fired heater flue gas in order to maximize heater efficiency and minimize greenhouse gas emissions. The emission limit of each of the greenhouse gases and CO_2e are as follows:

	tpy
CO_2	164,232.5
CH_4	9.3
N_2O	1.9
CO_2e	165,004.9

PROCESS EFFICIENCY BENCHMARKING

The existing design of the plant is much less efficient than other methanol plants that incorporate newer energy efficiency technologies. The current energy efficiency of the plant, as measured in MMBtu/MTPD is 42.02 MMBtu/MTPD. The post-project energy efficiency of the plant is estimated to be 35.66 MMBtu/MTPD (please see the enclosed energy efficiency study), a 15% increase in efficiency and similar to other methanol plants with similar designs. The following table outlines the energy efficiency of several plants in relation to the OCI plant (post-project).

DESCRIPTION	YEAR START-UP	NAMEPLATE CAPACITY	DESIGN YIELD	DESIGN TYPE
		MTPD	BASE LHV MMBTU/MTPD	
BEAUMONT METHANOL PLANT	1968	3000 (post project)	35.66	Design in one-step reforming (Two Terrace Reformers) Note 1
CHILE I METHANOL PLANT	1988	2,268	33.15	Design in one-step reforming (One Primary Top fired Reformer) Note 2
CHILE III METHANOL PLANT	1999	3,000	31.88	Design in one-step reforming (One Primary Top fired Reformer) Note 3
IRAN METHANOL PLANT	2004	5,000	29.86	Design in two-step reforming (Combined reformer with a Steam Reformer plus Autothemal Reformer) Note 4
EGYPT METHANOL PLANT	2010	3,600	30.56	Design in two-step reforming (Combined reformer with a Steam Reformer plus Autothemal Reformer) Note 5

Note 1: Conventional one-step reforming design. Original design from 1968 submitted to a Methanol Modernization (Synthesis Loop Revamp per LURGI design) in 1980. Nameplate Capacity of 3,000 MTPD (post-debottlenecking).

Note 2: Conventional one-step reforming design with introduction of Medium Pressure Steam Stripper for Process Condensate Hydrocarbons Recycling to Reformer and Clean Condensate to Water Recovery System.

Note 3: Conventional one-step reforming design with introduction of Natural Gas Saturator to recover Distillation Organic Waste, Distillation Waste Water and Process Condensate.

Note 4: Combined reforming design with introduction of a Pre-Reformer and Natural Gas Saturator.

Note 5: Combined Reforming design without Pre-Reformer but with Two Step Natural Gas Saturator.

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17 December, 2012

Mr. Frank Bakker
General Manager
OCI Beaumont LLC

Subject: <u>OCI Beaumont Methanol Plant Capacity Increase Project</u>

OCI Beaumont LLC (OCI) is the owner of a Methanol Plant and an Ammonia plant, both located at the OCI facility in Jefferson County, Texas.

The facility, located in the DuPont Beaumont Industrial Park, was originally built in 1969 by DuPont to produce methanol. The plant was re-designed in 1981 to convert from a methanol high pressure production train to a low pressure process train. An integrated anhydrous ammonia plant was built in 2000.

OCI is requesting that EPA and TCEQ authorize the operation of the methanol reformers beyond the three years that is currently allowed in Permit 901.

The OCI Methanol unit capacity is to be increased by the addition of a pre-reformer and associated fired heater, increase in reformer tubes diameter and addition of a Saturator column.

The addition of this proven technology allows significant energy efficiency improvement to the process as well as in the reduction of Greenhouse Gas (GHG) emissions.

OCI has requested INGEPROX Limited to provide Process/Project Management Technical Consultant Services on behalf of OCI for the Methanol plant capacity increase project.

INGEPROX Limited is in a position to provide Project Management and Engineering Services with a highly qualified team of Engineers with wide experience on project management and project development of Methanol and Ammonia process plants.

IHI E&C International Corporation (IHI E&C) has been awarded a contract by OCI to conduct Engineering and Procurement Services under the scope of work defined for the Methanol plant capacity increase project.

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IHI E&C is uniquely qualified to provide services associated with this plant. The OCI project is an excellent fit with IHI E&C's long heritage in projects of this kind, having designed and built over 25 methanol plants.

IHI E&C has extensive experience in all the units within this plant; namely steam methane reforming, heat recovery from flue and synthesis gases, methanol synthesis and distillation. IHI E&C also have extensive experience in revamp and debottlenecking.

IHI E&C experience in synthesis gas, methanol and revamp/debottlenecking comes for over 40 years where IHI E&C has designed and/or constructed 25 methanol plants throughout the world, as well as performed numerous feasibility studies, FEED packages and revamp and debottlenecking of existing methanol, ammonia and HYCO plants.

IHI E&C and INGEPROX Limited are most interested in supporting OCI's objective to develop and provide a safe and cost effective solution as described in the document below for the methanol plant capacity increase project by utilizing their extensive experience and engineering expertise in design and construction of synthesis gas and methanol plants.

Alejandro Sánchez
General Manager
INGEPROX Limited

Chris Neff
Vice President
IHI E&C International Corporation

REVIEWED

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OCI Beaumont Process Energy Efficiency Improvement Study

The objective of this report is to provide input to the Air Permit application relating to the major initiatives proposed by OCI Beaumont LLC to improve process energy efficiency by installing new/better technologies (based on benchmark comparison) using BACT (best available control technologies) and the positive impact on maximizing energy efficiency of the process to minimizing greenhouse gas emissions.

The debottlenecking of the plant will include the following modifications at a minimum:

- Addition of a Pre-Reformer and associated fired heater
- Increase in reformer tube diameter
- Addition of a Saturator

These modifications are expected to significantly increase the capacity of the methanol plant. As a basis for the air permit, a methanol production rate of 3,000 MTPD is used for the debottlenecking case comparison to the current plant operating case.

Addition of a Pre-Reformer System

Installing a Pre-Reformer has been chosen as the option to increase the capacity of the plant and improve the overall efficiency of the plant while decreasing GHG emissions.

A pre-reformer is an adiabatic fixed-bed reactor located upstream of the Steam Reformer Units (SRU's). The pre-reformer will provide the following:

- increased flexibility in the choice of feedstock,
- increased lifetime of the steam reforming catalyst and tubes,
- decrease the heat load of the primary reformer maintaining synthesis gas throughput and the
- ability to increase the overall plant capacity.

The saturated natural gas process feed is mixed with process steam, heated, and then enters a new Pre-Reformer. In the Pre-Reformer, any hydrocarbon heavier than methane is converted into methane. Since natural gas contains approximately 2.5% C_2+, converting this portion to methane in the Pre-Reformer helps to increase the plant throughput.

The Pre-Reformer is filled with high nickel containing catalyst where the following reactions take place:

$C_n H_m + nH_2O \leftrightarrow nCO + (m/2 + n) H_2$

$CO + 3 H_2 \leftrightarrow CH_4 + H_2O$ (methanation reaction)
$CO + H_2O \leftrightarrow CO_2 + H_2$ (water shift reaction)

Since these reactions are endothermic, there is a drop in temperature across the Pre-Reformer catalyst bed. The effluent from the Pre-Reformer must be heated again before being introduced into the SRU. The feed to the Pre-Reformer must be heated also by the introduction of a New Fired Heater.

For this study the Pre-Reformer feed gas is mixed with process steam and then is heated by waste heat recovery from the process. Additional heat is provided by a new fired heater to obtain the required operating temperature of the Pre-Reformer. Addition of all the steam upstream of the Pre-Reformer maximizes the Pre-Reformer performance.

The pre-reformer fired heater will provide heat for pre-heating the process feed from the saturator to the pre-reformer and for pre-heating the natural gas feed to the desulfurization unit. The pre-reformer effluent to the mixed feed heater coil is used to preheat the feed to the fired heater and resulting in a waste heat integration that makes the process more efficient and requires less energy for the fired heater.

Increase in Reformer Tubes Diameter

Another improvement is the replacement of the reformer tubes with larger diameter tubes in the Steam Reformers. The new tubes will have thinner wall thickness. This change is based upon a Schmidt + Clemens Study concluded in 2009 presented at the International Methanol Technology Operators Forum hosted by Johnson Matthey Catalyst.

The new tubes will contain more catalyst and the heat transfer from the firebox is improved by the thinner wall thickness. This means less firing is required compared to that required for the old tubes for same amount of synthesis gas throughput.

With the pre-reformer and the new tubes, the reformer can be operated at higher capacity conditions to provide increased production rates. Alternatively, to maintain the current plant capacity the reformers could be operated at a lower outlet temperature (which means less firing required).

Addition of a Saturator

The current Gas-Liquid convection burners in the SRU are designed to burn organic liquid from the Distillation side streams (Stripper Tails). This organic liquid stream is mainly a mix of Methanol, Ethanol and Water with some amount of more heavy alcohols.

The liquid stream to be burned in the reformer convection section is < 20% of combined alcohols. This results in a liquid stream being burned with a high concentration of water. To accomplish this, a large amount of fuel gas as well as excess air must also be burned.

This results in a high contribution of NOx emissions from these burners during normal operation of the methanol plant because the Stripper Tails stream must be continuously burned.

Additionally a part of the organic liquid stream is from the bottom of the Dehydrator column that is sent to a third party wastewater treatment plant. This stream, which is mainly wastewater from distillation, is in the range of 15-20 m^3/hr (65-90 gpm). This wastewater stream has very low content of methanol and traces of other alcohols, and can very easily be treated and recovered as steam for the reformer.

Current Standard Methanol Plant design (with or without Autothermal Reformer (ATR) technology) uses what it is called a Gas Saturator where the Natural Gas is saturated with a process water stream to be recovered as steam for the reformers. This decreases the demand of boiler generated steam to meet the steam to carbon ratio requirements for the reformer operation.

The advantage of a Saturator is that it will process the organic liquid stream instead of burning it in the convection section of the reformers. This reduces the NOx and GHG emissions and improves the steam/water balance of the plant through the recovery of approximately 100 ton/hr of water as steam. This provides a positive direct impact on the efficiency of the plant as well as the reduction in GHG emissions.

The stripper tails, dehydrator water stream and process condensate will be fed as a liquid stream to the top of this saturator packed column. The natural gas used as feedstock for the methanol process will be sent as a gaseous stream to the bottom of the saturator column. The gas flows upward in the column and the liquid falls down in the packed column. This means that there will be a very effective mixing between these two phases. During this mixing process, the water and the organic components in the liquid stream will evaporate and transfer to the natural gas stream. This means that most of the organics will go to the natural gas stream and will be used as feedstock to the process instead of having to be treated as wastewater (dehydrator water) or to be burned (stripper tails).

Furthermore, much of the steam that is needed to be mixed with the natural gas for the steam reforming is already transferred to the natural gas stream in the saturator column; the natural gas being saturated with water. The natural gas with water vapor and organics exits the top of the saturator and follows its current route in the process.

The remaining liquid stream, with a low VOC concentration, that leaves the saturator column at the bottom is very small compared to the original flow of this stream (approximately 10% of the original water stream) and is sent to the wastewater treatment plant.

To summarize: the saturator has the following environmental and energy efficiency advantages:

- The stripper tails will no longer will have to be "burned" in the reformer convection section. This will save natural gas, and will reduce the reformer flue gas emissions.
- The dehydrator water stream will be used effectively and the amount of waste water sent to the waste water treatment plant will be greatly reduced.
- A major part of the organic components present in the stripper tail gas and the dehydrator water will be used as process feedstock reducing the need for natural gas feedstock.
- The process condensate will be recycled to the saturator, no longer requiring the atmospheric CO_2 stripper, a positive impact in decreasing GHG emissions.
- The amount of steam needed to be put into the natural gas for the steam reforming process will be reduced. This steam requirement reduction saves energy.

Expected Overall Efficiency and GHG impact

The overall efficiency increase and the plant yield measured as the amount of energy required to produce one metric ton of methanol is expected to decrease from the original plant design case of 42.02 MMBTU/MT to 35.66 MMBTU/MT resulting in an overall reduction of 6.36 MMBTU of energy required to produce 1 MT of methanol.

APPENDIX C – REFERENCES

[1] US EPA, Office of Air Quality Planning and Standards, "PSD and Title V Permitting Guidance for Greenhouse Gases", March 2011.
[2] "Report of the Interagency Task Force on Carbon Capture and Storage", August 2010.
[3] US EPA, Office of Air and Radiation, "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers", October 2010.
[4] US EPA, "EPA Air Pollution Control Cost Manual", 6th ed., (EPA/452/B-02-001), January 2002.