INVISTA™

INVISTA S.à r.l.
Victoria Site
P. O. Box 2626
Victoria, TX 77902-2626

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VIA FEDEX AND EMAIL

September 17, 2013

Mr. Jeff Robinson
Air Permits Section Chief
U.S. Environmental Protection Agency, (6PD-R)
1445 Ross Ave
Dallas, TX 75202-2733

Mr. Robinson:

Re: Greenhouse Gas Prevention of Significant Deterioration (PSD) Permit Application
Combined Hydrogen/Ammonia Unit
INVISTA S.à r.l
Victoria Plant
Victoria, Victoria County, Texas

On behalf of INVISTA S.à r.l (INVISTA), I am submitting the enclosed application for a Greenhouse Gas (GHG) PSD permit for the proposed INVISTA Victoria combined hydrogen and anhydrous ammonia manufacturing unit. The proposed project will comprise of a hydrogen reformer, an ammonia synthesis unit, an air separation unit, and associated supporting equipment, located at INVISTA's existing Victoria Site in Victoria County, Texas.

This permit application has been prepared in accordance with U.S. EPA guidance, including "PSD and Title V Permitting Guidance for Greenhouse Gases," EPA-457/B-11-001, March 2011, EPA's October 15, 2012 Memo "Timely Processing of PSD Permits when EPA or a PSD-Delegated Air Agency Issues the Permit", the RACT/BACT/LAER Clearinghouse, and other materials.

The purpose of this permit application is to authorize the following GHG emission points:

1. **One steam methane reformer (EPN 03V901)** – to convert natural gas to hydrogen;
2. **One start-up heater (EPN 08B001)** – natural gas fired heater used to start up the ammonia converter;
3. **One hydrogen flare (EPN 06V801) and one ammonia flare (EPN 06V802)** – to control emissions from dry gas seals, and during malfunctions and planned maintenance, start-up, and shut-down

(MSS). The hydrogen flare also has the potential to flare H_2 during product demand changes or when the system is not balanced; and

4. **Fugitive emissions (EPNs FUG-PSA, FUG-HBOG, and FUG-NG)** – emissions from fugitive components (valves, connectors, pumps, etc.)

The enclosed attachments include the GHG application, the Biological Assessment, and the Cultural Resources Assessment. The package is being delivered via FedEx and via email as requested by EPA.

If you have any questions regarding this submittal, please call Geri Shoop at 361.580.5951 or email Geri.Shoop@invista.com.

Sincerely,

Paul Hughes
Director of Texas Core Intermediates

cc: Ms. Melanie Magee, EPA Region 6, Dallas, w/enclosures

GREENHOUSE GAS PSD PERMIT APPLICATION

INVISTA S.à r.l. Victoria Site

Combined Hydrogen/Ammonia Unit

Prepared By:

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Houston, TX 77027
(713) 552-1371

September 17, 2013

Project 134402.0053

Trinity Consultants

Environmental solutions delivered uncommonly well

TABLE OF CONTENTS

LIST OF TABLES

1. PROJECT OVERVIEW AND DESCRIPTION

1.1. EXECUTIVE SUMMARY

INVISTA S.à r.l. (INVISTA) owns and operates a chemical manufacturing facility (nylon intermediates plant) in Victoria, Victoria County, Texas (Victoria Site). INVISTA proposes to construct and operate a new hydrogen and anhydrous ammonia manufacturing unit comprising of a hydrogen reformer, an ammonia synthesis unit, an air separation unit, and associated supporting equipment, located at INVISTA's existing Victoria Site in Victoria County, Texas. The new unit will be designed such that the hydrogen unit can be operated independently; however, operating the ammonia unit will require the hydrogen unit to be operational.

With this submittal, INVISTA is requesting to authorize the following GHG emission points:

- **One steam methane reformer (EPN 03V901)** – to convert natural gas to hydrogen
- **One start-up heater (EPN 08B001)** – natural gas fired heater used to start up the ammonia converter
- **One hydrogen flare (EPN 06V801) and one ammonia flare (EPN 06V802)** – to control emissions from dry gas seals, and during malfunctions and planned maintenance, start-up, and shut-down (MSS). The hydrogen flare also has the potential to flare H_2 during product demand changes or when the system is not balanced.
- **Fugitive emissions (EPNs FUG-PSA, FUG-HBOG, and FUG-NG)** – emissions from fugitive components (valves, connectors, pumps, etc.)

The hydrogen/ammonia unit will also include a cooling tower, but there are no GHG emissions from the cooling tower so it is not addressed further in this GHG PSD permit application.

The proposed project will trigger Federal Prevention of Significant Deterioration (PSD) review for GHG emissions because it is proposed at an existing PSD major source and the GHG emissions from the proposed project will exceed 75,000 tons/yr CO_2e. Hence, to authorize GHG emissions from the proposed unit, this application is being submitted for an initial (new) major PSD GHG pre-construction permit.

The proposed project will also trigger Federal PSD review for NO_x, CO, VOC, PM, $PM_{2.5}$, and PM_{10}. Accordingly, an application for a Prevention of Significant Deterioration (PSD) and state new source review permit for non-GHG emissions will be submitted to the TCEQ.

The following table summarizes the proposed BACT emission limits.

Table 1-1. Summary of Proposed BACT limits

Source	Proposed Emission Controls	Proposed Emission Limit
Steam Methane Reformer	Implement energy efficient design and operating practices.	1,879,561 tons CO_2e total per 365-days (rolling)
Start-up Heater	Implement energy efficient design and operating practices.	Low carbon fuel and work practice standard
Hydrogen Flare	Use natural gas for the pilots, implement good flare design, and follow good combustion practices.	Minimize flaring and work practice standard

Source	Proposed Emission Controls	Proposed Emission Limit
Ammonia Flare	Use natural gas for the pilots, implement good flare design and follow good combustion practices.	Minimize flaring and work practice standard
Fugitives – PSA Offgas	Implement leak detection and repair under a TCEQ 28VHP LDAR program.	Work practice standard
Fugitives – High-Btu Offgas	Implement leak detection and repair under a TCEQ 28VHP LDAR program.	Work practice standard
Fugitives – Natural Gas	Implement leak detection and repair under a TCEQ 28VHP LDAR program.	Work practice standard

All required supporting documentation for the permit amendment is provided in this application. Applicant information is included in Section 1.2 of this application. The project location is discussed in Section 1.3, with local and regional area maps indicating the site location provided in Sections 1.3.1 and 1.3.2, respectively. A project description is provided in Section 1.4, including a process flow diagram in Section 1.4.6 and a plot plan in Section 1.4.7. PSD Applicability, including emission calculations, is covered in Section 2. A discussion of Best Available Control Technology (BACT) is provided in Section 3. Requirements pertaining to air quality analysis, analysis of Class I Area impacts, and additional impact analysis are discussed in Sections 4, 5, and 6, respectively. Compliance with other EPA requirements and non-Clean Air Act requirements are discussed in Sections 7 and 8, respectively.

1.2. APPLICANT INFORMATION

Refer to TCEQ PI-1 form in Section 1.2.1.

1.2.1. PI-1 Form

TCEQ

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

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: INVISTA S.à r.l.		
Texas Secretary of State Charter/Registration Number (if applicable): 12417006		
B. Company Official Contact Name: Paul Hughes		
Title: Director of Texas Core Intermediates Operations		
Mailing Address: P.O. Box 2626		
City: Victoria	State: Texas	ZIP Code: 77902-2626
Telephone No.:	Fax No.:	E-mail Address:
C. Technical Contact Name: Geri Shoop		
Title: Sr. Environmental Specialist		
Company Name: INVISTA S.à r.l.		
Mailing Address: P.O. Box 2626		
City: Victoria	State: Texas	ZIP Code: 77902-2626
Telephone No.: 361-580-5951	Fax No.: 361-572-1515	E-mail Address: Geri.Shoop@invista.com
D. Site Name: Victoria Plant		
E. Area Name/Type of Facility: Combined Hydrogen/Ammonia Unit		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Nylon Intermediate Chemicals		
Principal Standard Industrial Classification Code (SIC): 2869		
Principal North American Industry Classification System (NAICS): 325199		
G. Projected Start of Construction Date: First Quarter 2015		
Projected Start of Operation Date: First Quarter 2017		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 2695 Old Bloomington Road North		
City/Town: Victoria	County: Victoria	ZIP Code: 77905
Latitude (nearest second): 28° 67' 06"	Longitude (nearest second): 96° 95' 67"	

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

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: Paul Hughes

Signature:________________________
Original Signature Required

Date: 9/17/13

Consultant Information

A. Company or Other Legal Name: Trinity Consultants

B. Company Official Contact Name: Raghu Soule

Title: Managing Consultant

Mailing Address: 1001 West Loop South, Suite 640

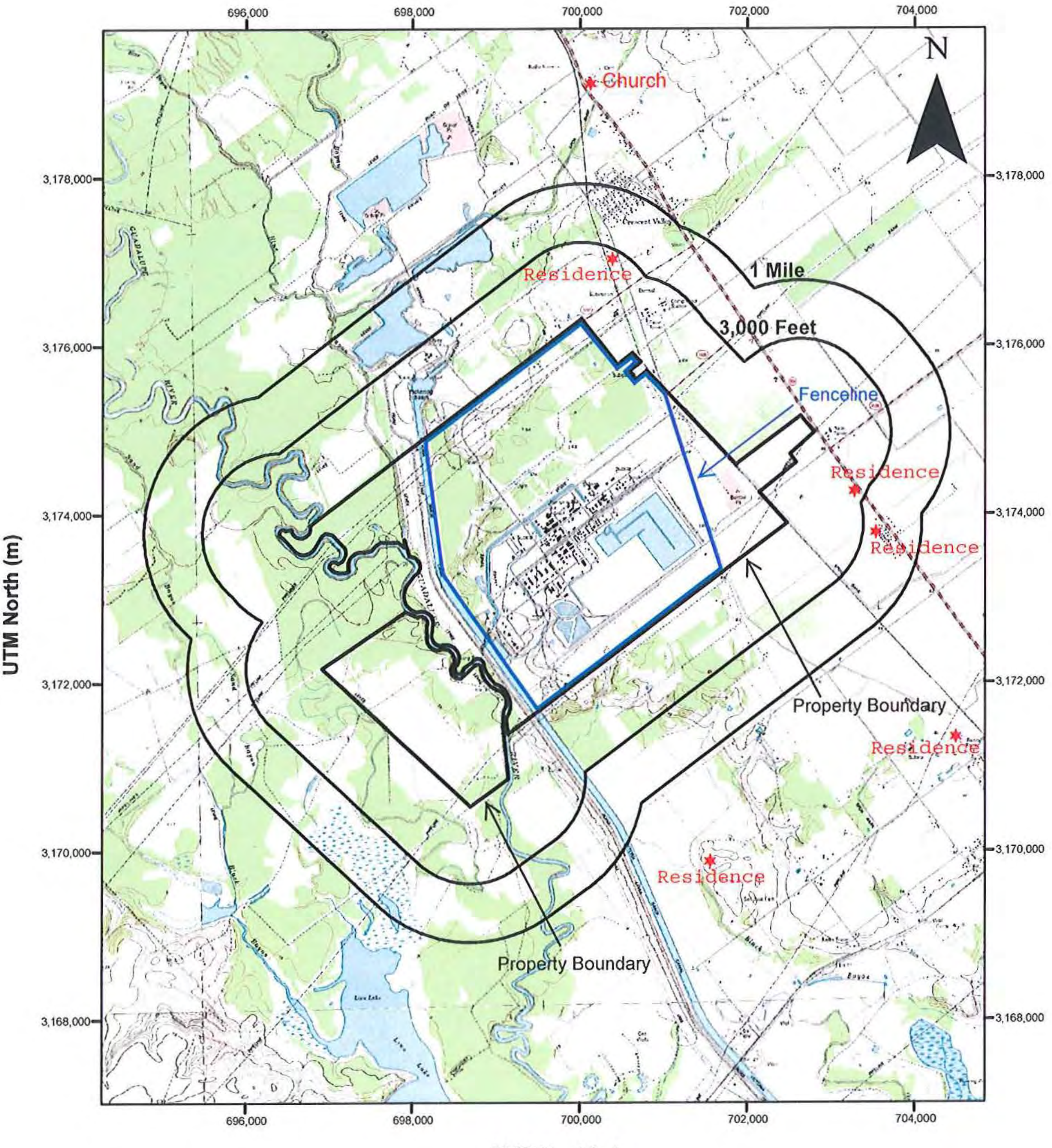
City: Houston	State: TX	ZIP Code: 77027
Telephone No.: 713-552-1371 x206	Fax No.: 713-552-1374	E-mail Address: rsoule@trinityconsultants.com

1.3. PROJECT LOCATION

The project will be located at INVISTA's Victoria Site, 2695 Old Bloomington Road North, Victoria, Texas 77905. The nominal coordinates of the site are Latitude: 28° 67' 06" and Longitude: 96° 95' 67". The Victoria Site is currently used for INVISTA's chemical manufacturing facility (nylon intermediates plant). A local map is provided in Section 1.3.1 and a regional map is provided in Section 1.3.2.

1.3.1. Local Map

INVISTA Victoria Area Map



Scales
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Feet
0 1,000 2,000 3,000 4,000
Meters

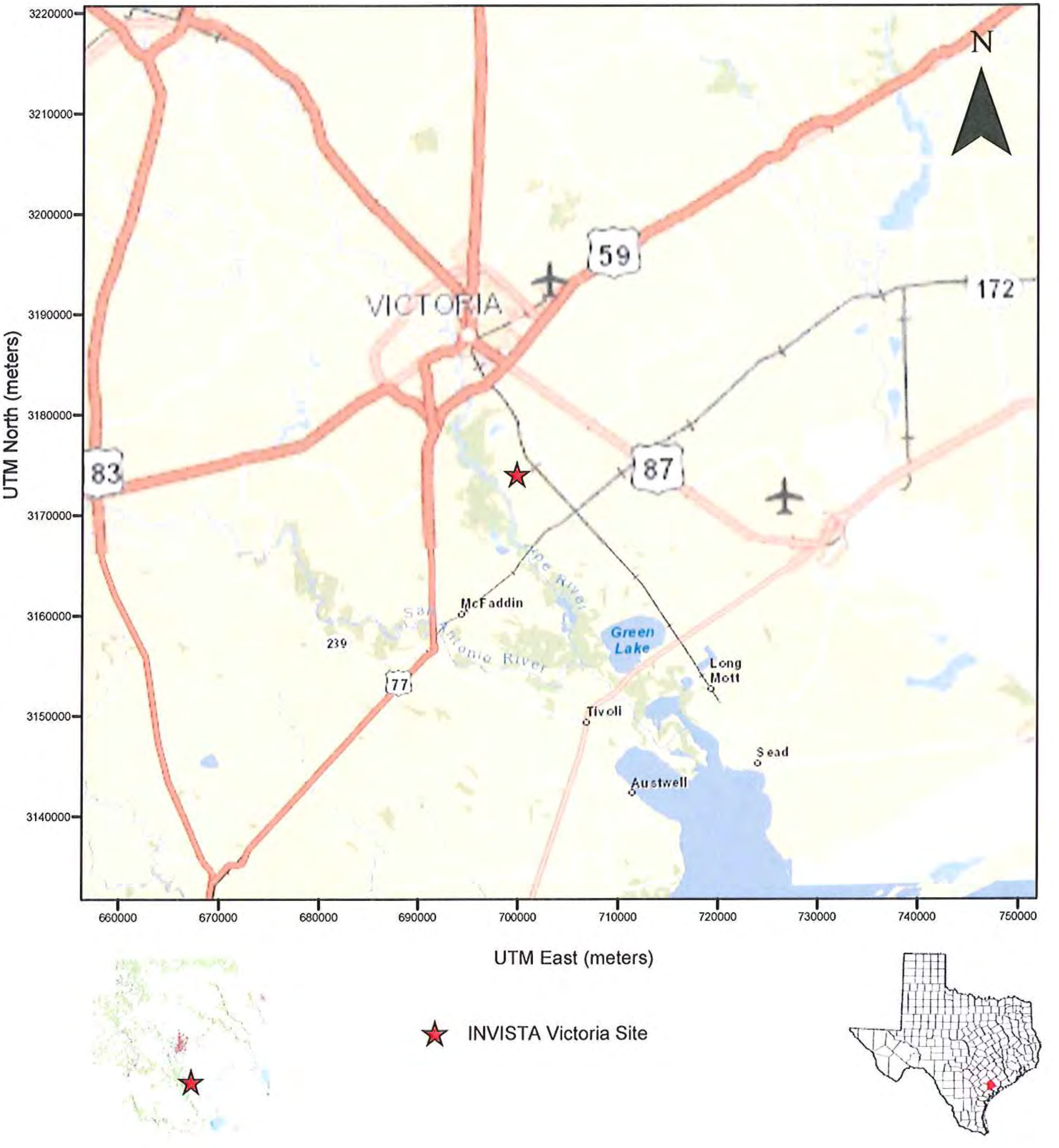
Coordinate System:
NAD 1983 UTM Zone 14N

Trinity Consultants

Date: 6/26/2013

1.3.2. Regional Map

INVISTA Victoria Regional Map



Map: Esri World Street Map Basemap
Coordinate System:
NAD 1983 UTM Zone 14
Date: 09/12/2013

Trinity Consultants

1.4. PROJECT DESCRIPTION

1.4.1. Introduction and Purpose

INVISTA owns and operates a chemical manufacturing facility (nylon intermediates plant) at the Victoria Site. INVISTA proposes to construct and operate a new hydrogen and anhydrous ammonia manufacturing unit comprising of a hydrogen unit, an ammonia unit, an air separation unit, and new associated support equipment. The new unit will be located at INVISTA's existing Victoria Site. The unit produces hydrogen, ammonia, nitrogen, oxygen, and high pressure steam to serve INVISTA's existing Victoria Site which is covered by SIC code 2869 (Organic Chemical Manufacturing).

INVISTA is proposing energy efficiency measures for the hydrogen/ammonia unit, along with TCEQ's 28VHP leak detection and repair program for fugitive components, as discussed in Section 3. The reformer stack will be equipped with sampling ports and a CO_2 Continuous Emissions Monitoring System (CEMS).

The combined hydrogen/ammonia unit, with the ability to produce hydrogen independent from ammonia, is highly unique in the United States—INVISTA believes this facility is the first of its kind in the U.S. The plant will be designed to be among the top ten percent most energy efficient hydrogen/ammonia units in the world. One important feature of both energy and economic efficiency is the plant's extremely high design reliability rate. The plant is designed to achieve that reliability rate on an annual basis for each of the four years between major maintenance turnarounds. The high reliability design is a critical feature of the project, as the reliability must be high enough to justify the project versus continued import of ammonia to the facility.

Below is a brief description of the process. A process flow diagram is included in Section 1.4.6 and a plot plan is included in Section 1.4.7.

1.4.2. Hydrogen Unit

The hydrogen unit is based on steam methane reforming (SMR) technology. Its purpose is to serve the hydrogen demand of existing users and the new ammonia unit.

Downstream of a desulphurization unit, natural gas will be fed to a conventional steam reformer. Here, methane and water will be transformed via an endothermic reaction to hydrogen, along with carbon monoxide (CO) and carbon dioxide (CO_2). In order to produce high purity hydrogen, the reformed gas will pass through a CO shift section and a pressure swing adsorption (PSA) unit where impurities will be separated.

High-Btu offgas coming from existing INVISTA facilities, PSA Offgas, and natural gas will be used as fuel for the steam reformer, during normal operations. A minor fuel gas stream (ammonia fuel gas) from the ammonia unit will also be used as fuel for the reformer, as described in the next section. During start-up of the reformer, steam may be imported from the existing West Powerhouse (WPH) Boilers. The WPH Boilers have been authorized for GHG emissions under permit number PSD-TX-812-GHG, issued May 14, 2013.

The majority of the hydrogen will be fed to the ammonia unit for production of high purity ammonia; some of the hydrogen will be exported to the existing INVISTA's facilities.

1.4.3. Ammonia Unit

Nitrogen produced by the air separation unit (described in the section below) will be mixed with hydrogen from the hydrogen unit. This mixture, called synthesis gas, will be compressed to a suitable pressure for ammonia production. Using a catalyst, ammonia synthesis will be carried out in a closed loop process. Other than a small recycle stream, the ammonia formed will be condensed, separated, and fed to an ammonia storage tank which is part of the existing INVISTA facilities.

Low temperature cooling duty will be provided by a refrigeration unit that is a part of the ammonia unit. Liquid ammonia will be used as a refrigerant and vaporized in order to cool the ammonia produced in the closed loop process.

A closed loop process will be used for ammonia production. As such, a continuous flow will be purged from the loop process in order to keep inert components at a constant concentration. The gas that is separated (flash gas) will be fed to an absorption-desorption process to recover ammonia. The offgas from the absorption-desorption process, called ammonia fuel gas, will be used as a fuel gas for the reformer within the hydrogen unit.

1.4.4. Air Separation Unit

The air separation unit will produce nitrogen as well as oxygen at a high purity level. The majority of the nitrogen will be used in the ammonia unit, while excess nitrogen and pure oxygen will be exported to the existing INVISTA's facilities for further use.

1.4.5. Associated Support Equipment

1.4.5.1. Cooling water system

The new cooling water system will consist of a cooling tower and cooling water pumps. Losses due to evaporation inside the cooling tower will be replaced by cooling water make-up.

1.4.5.2. Instrument and plant air

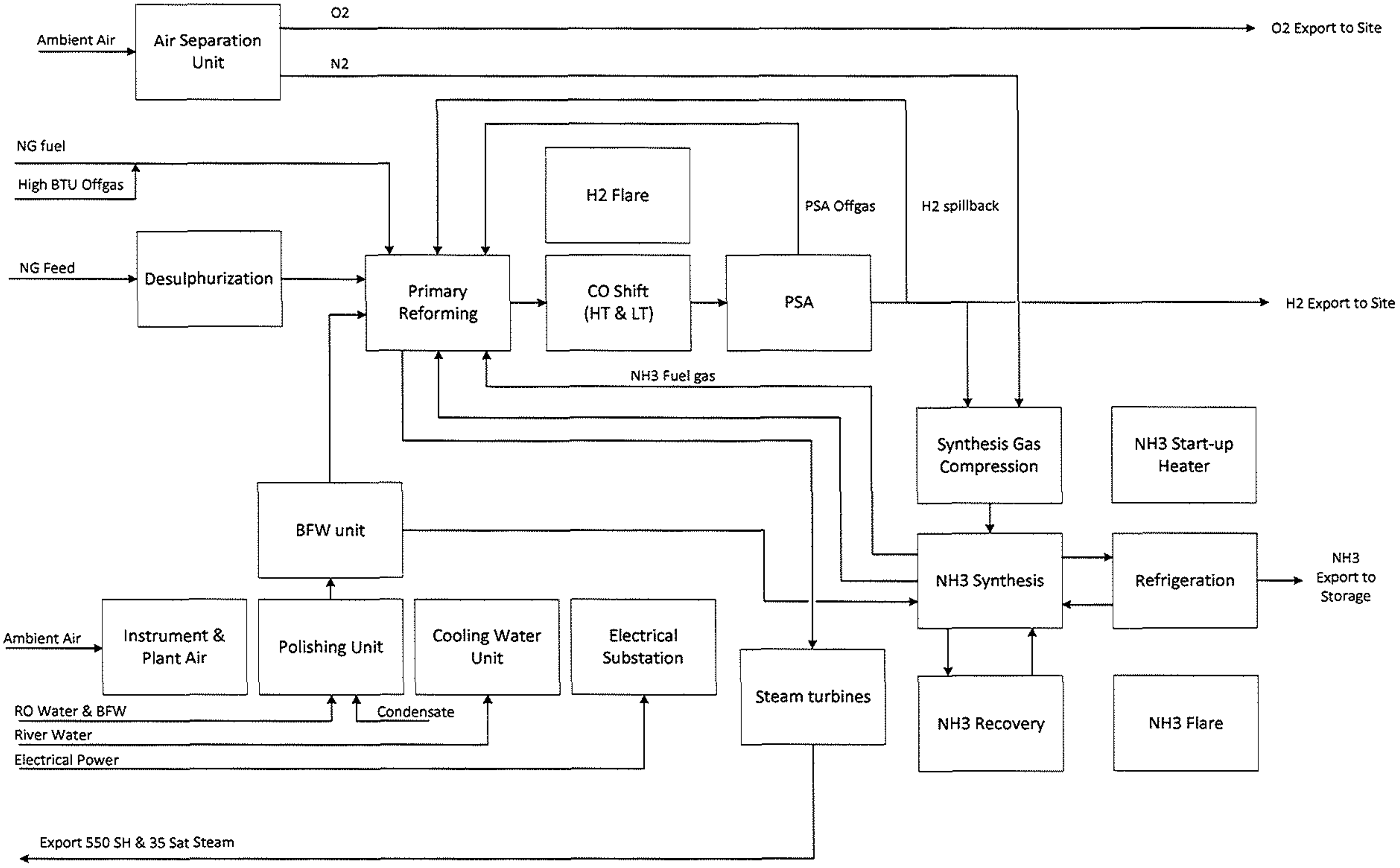
The new instrument and plant air system will serve the demand of several air consumers inside the new hydrogen/ammonia unit. An air compressor and air drying unit will be used to provide necessary air for air-driven instruments. Connections to the existing instrument air systems will provide backup instrument air.

1.4.5.3. Water treatment system

The main purpose of the new water treatment system is to provide boiler feed water for use inside the hydrogen/ammonia unit. The water treatment system will use steam condensate coming from the new hydrogen/ammonia unit, as well as boiler feed water and reverse osmosis water from the existing INVISTA facilities.

1.4.6. Process Flow Diagram

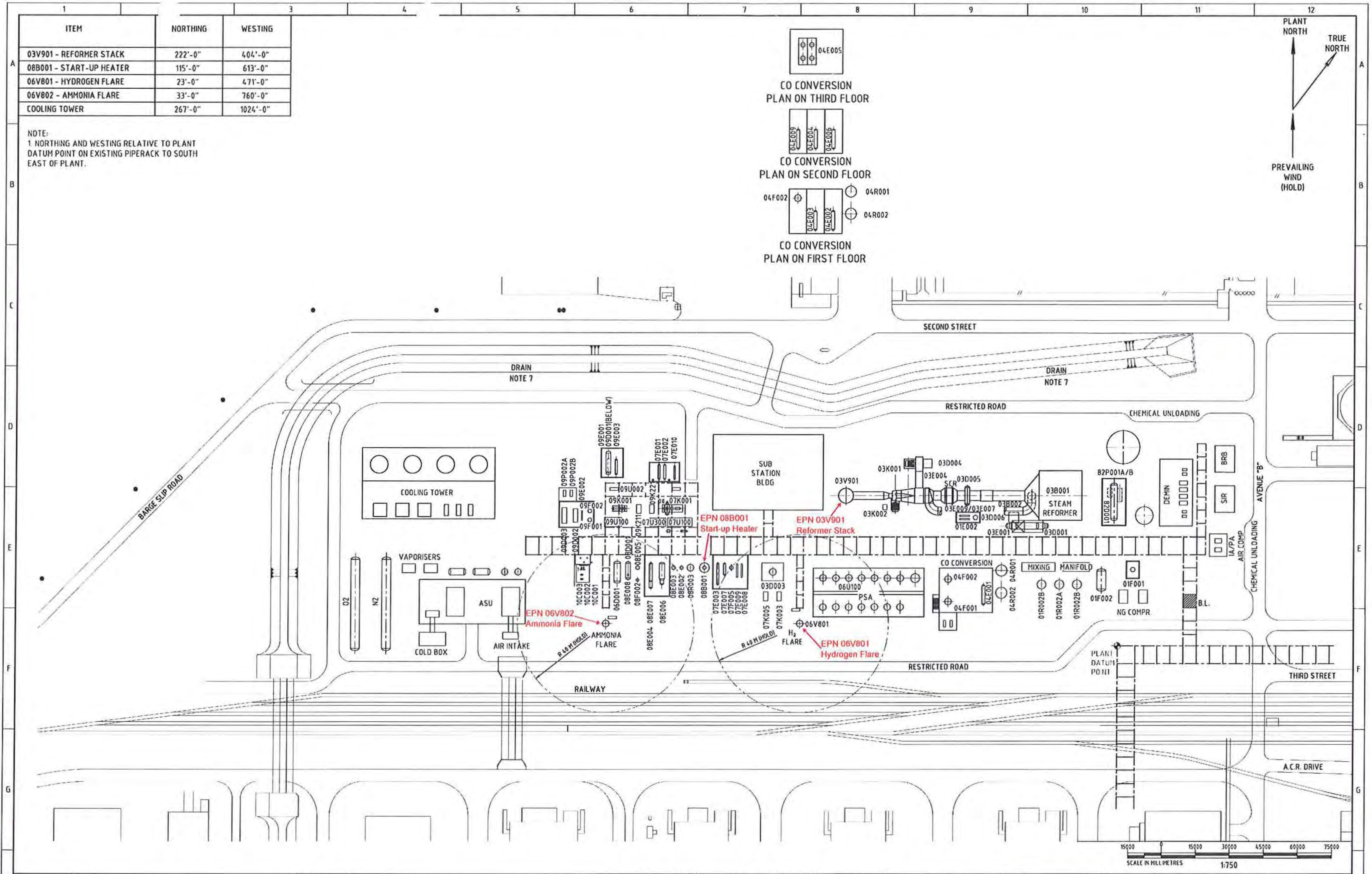
Process Flow Diagram



1.4.7. Plot Plan

ITEM	NORTHING	WESTING
03V901 - REFORMER STACK	222'-0"	404'-0"
08B001 - START-UP HEATER	115'-0"	613'-0"
06V801 - HYDROGEN FLARE	23'-0"	471'-0"
06V802 - AMMONIA FLARE	33'-0"	760'-0"
COOLING TOWER	267'-0"	1024'-0"

NOTE:
1. NORTHING AND WESTING RELATIVE TO PLANT DATUM POINT ON EXISTING PIPERACK TO SOUTH EAST OF PLANT.



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		B		PRELIMINARY ISSUE	HDR	BXP	BXP	AJH			
		A	13-5-13	PRELIMINARY ISSUE	LCN	BXP	BXP	AJH			

Uhde Shedden

ThyssenKrupp

CLIENT

INVISTA

PROJECT: 25926

SCALE: 1:750

TITLE

INVISTA HYDROGEN & AMMONIA PLANT
CONCEPT PLOT PLAN
OPTION B

DRAWING NUMBER

USAPL-PI-LD-00001

REV.

B

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1.5. CONSTRUCTION SCHEDULE

Pending issuance of required permits, the projected construction start date is 1Q 2015 and the startup of operation is 1Q 2017.

2. PSD APPLICABILITY SECTION

2.1. EMISSION CALCULATIONS

There are several different operating scenarios for the hydrogen/ammonia unit, as described below. As mentioned earlier, the hydrogen unit can operate independently of the ammonia unit. However, the ammonia unit cannot operate independently; operating the ammonia unit will require the hydrogen unit to be operational. The various operating scenarios are based primarily on the following variables:

- Type of fuel (PSA offgas, natural gas and/or high Btu plant off-gas)
- Mode of production (hydrogen or hydrogen/ammonia)
- Amount of hydrogen produced for export
- Steam production (minimum, normal, or maximum)

Based on the interplay of the above factors, the hydrogen/ammonia unit could be operated in various operating scenarios depending on the demands of the site. For the purposes of this permit application, the case representing the most conservative scenario from the perspective of maximum GHG emissions is utilized to develop emission limits. Additional operating scenarios have been considered for the high Btu plant off-gas fuel and for flare-related emissions.

Table 2-1 provides the Global Warming Potential (GWP) for the three greenhouse gases expected to be emitted from the proposed hydrogen/ammonia unit. The GWP is based on a 100-year time horizon. These data are taken from Table A-1 of 40 C.F.R. Part 98.

Table 2-1. Global Warming Potentials

Pollutant	GWP
CO_2	1
CH_4	21
N_2O	310

A summary of the GHG emissions from this project on a CO2e basis is shown in the Table 2-2. This section contains a detailed description of the calculation methodology used to determine the proposed emission rates for all sources affected by this project. Table 1(a) is provided in Section 2.2. Detailed GHG emission calculations are included in Appendix A.

Table 2-2. Summary of GHG Emissions

EPN	Emission Unit Description	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	Total CO_2e[1] (tpy)
03V901	Steam Methane Reformer	1,874,299	<0.01	<0.01	1,874,301
03V901-MSS	Steam Methane Reformer MSS	5,255	0.09	0.01	5,260
08B001	Start-up Heater	3,608	0.07	0.01	3,612
06V801	Hydrogen Flare	2,225	0.04	<0.01	2,227
06V801-MSS	Hydrogen Flare MSS	14,820	<0.01	<0.01	14,820
06V802	Ammonia Flare	2,225	0.04	<0.01	2,227

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[1] Based upon Global Warming Potentials (GWP) for Methane (21) and N_2O (310).

EPN	Emission Unit Description	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	Total CO_2e[1] (tpy)
06V802-MSS	Ammonia Flare MSS	9.17	<0.01	<0.01	9.17
FUG-PSA	Fugitives – PSA Offgas	8.23	2.25	---	55.4
FUG-HBOG	Fugitives – High-Btu Offgas	0.17	0.15	---	3.37
FUG-NG	Fugitives – Natural Gas	0.29	50.75	---	1,066

2.1.1. Reformer (EPN 03V901)

The reformer converts methane and water to hydrogen, carbon monoxide and carbon dioxide. Annual emissions are based on 8760 hours of operation per year. For natural gas, the CO_2 emissions factor is based on EPA's technical support document for hydrogen plants, page 9, Table H5, while the Methane and Nitrous Oxide emissions factors are based on 40 C.F.R. Part 98, Subpart C, Table C-2. For High-Btu Off-gas, the GHG emission factors are based on site-specific data for this gas. Detailed emission calculations are provided in Appendix A.

2.1.2. Reformer Maintenance, Startup, and Shutdown (MSS) (EPN 03V901-MSS)

MSS for the reformer is defined by the period from first combustion of fuel in the reformer burners until the point when the reformer stack SCR (NOx control) is engaged. It is expected that due to temperature requirements prior to engaging the NH3 injection for the SCR NOx control that a minimum bed temperature must be reached. This temperature is estimated to be approximately 40% of the total heat input load of the reformer. The emission calculations for MSS emissions from the reformer are based upon less than 300 hours per year. The CO_2 emission factor is based on EPA's technical support document for hydrogen plants, page 9, Table H5.[2] CH_4 and N_2O emissions factors are from 40 C.F.R. Part 98, Subpart C, Table C-2. Detailed emission calculations are provided in Appendix A.

2.1.3. Start-up Heater (EPN 08B001)

The start-up heater is fueled solely by natural gas and is used for starting up the ammonia converter. Annual emissions are based on less than 1300 hours per year. CO_2 emissions are based on emission factors from Table C-1 of 40 C.F.R. Part 98, Subpart C for combustion sources. N_2O and CH_4 emissions are based on emission factors from Table C-2 of 40 C.F.R. Part 98, Subpart C for combustion sources. Detailed emission calculations are provided in Appendix A.

2.1.4. Hydrogen Flare (EPN 06V801)

The hydrogen flare utilizes continuous pilots as part of the design of the flare. Normal operation will consist of pilot flaring. Annual emissions are based on 8760 hours of operation per year. GHG emissions from normal operation of the flare are from natural gas pilot flaring, and emission factors are based on Table C-1 and C-2 of 40 C.F.R. Part 98, Subpart C for combustion sources. Detailed emission calculations are provided in Appendix A.

2.1.5. Hydrogen Flare MSS (EPN 06V801-MSS)

Non-ammonia gas streams released from the hydrogen/ammonia unit during malfunctions and planned MSS are routed to the hydrogen flare. The hydrogen flare also has the potential to flare H_2 during product demand changes or when the system is not balanced. Annual emissions are based on the frequency and duration of each activity, as shown in Appendix A. GHG emissions resulting from planned MSS and product demand change flaring are

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[2] "Technical Support Document for Hydrogen Production: Proposed Rule for Mandatory Reporting of Greenhouse Gases" Office of Air and Radiation U.S. Environmental Protection Agency, August 5th 2008.

calculated based on the total carbon flow rate to the flare. Detailed emission calculations are provided in Appendix A.

2.1.6. Ammonia Flare (EPN 06V802)

The ammonia flare utilizes continuous pilots as part of the design of the flare. During normal operation, the natural gas pilots and dry gas seals emissions will be flared. Annual emissions are based on 8760 hours of operation per year. The dry gas seals composition is mainly hydrogen and nitrogen, with a negligible amount of carbon and some ammonia. Therefore dry gas seals are not included in the GHG emissions for the flare. GHG emissions from normal operation of the flare are a result of natural gas pilot flaring, and emission factors are based on Table C-1 and C-2 of 40 C.F.R. Part 98, Subpart C for combustion sources. Detailed emission calculations are provided in Appendix A.

2.1.7. Ammonia Flare MSS (EPN 06V802-MSS)

Gas streams containing ammonia released from the hydrogen/ammonia unit during malfunctions and planned MSS are routed to the Ammonia Flare. Annual emissions are based on the frequency and duration of each planned MSS activity, as shown in Appendix A. GHG emissions resulting from planned maintenance, startup and shutdown are calculated based on the total carbon flow rate to the flare. Detailed emission calculations are provided in Appendix A.

2.1.8. PSA-Offgas Fugitives (EPN FUG-PSA)

PSA-offgas fugitive emissions are calculated using the methodology described in the TCEQ document entitled *"Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000"*, using emissions factors based on SOCMI without ethylene and control factors based upon the 28VHP program. Annual emissions are based on 8760 hours of operation per year. Detailed emission calculations are provided in Appendix A.

2.1.9. High-Btu Offgas Fugitives (EPN FUG-HBOG)

High-Btu offgas fugitive emissions are calculated using the methodology described in the TCEQ document entitled *"Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000"*, using emissions factors based on SOCMI without ethylene and control factors based upon the 28VHP program. Annual emissions are based on 8760 hours of operation per year. Detailed emission calculations are provided in Appendix A.

2.1.10. Natural Gas Fugitives (EPN FUG-NG)

Natural gas fugitive emissions are calculated using the methodology described in the TCEQ document entitled *"Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000"*, using emissions factors based on SOCMI without ethylene and control factors based upon the 28VHP program. Annual emissions are based on 8760 hours of operation per year. Detailed emission calculations are provided in Appendix A.

2.1.11. Associated Support Equipment

There are no GHG emissions from any associated support equipment, *i.e.*, the cooling water system, the instrument and plant air system, and the water treatment system.

2.2. TABLE 1(A)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	Sep-13	**Permit No.:**		**Regulated Entity No.:**	RN102663671
Area Name:	Combined Hydrogen/Ammonia Unit			**Customer Reference No.:**	CN602582231

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) Metric Tons of CO_2e per year**	**(B) TPY CO_2e**
03V901	03V901	Steam Methane Reformer	CO_2	1,852,074	1,874,299
			CH_4	1.98	2.01
			N_2O	0.02	0.02
03V901-MSS	03V901-MSS	Steam Methane Reformer MSS	CO_2	5,193	5,255
			CH_4	2.06	2.08
			N_2O	3.03	3.07
08B001	08B001	NH3 Start-up Heater	CO_2	3,565	3,608
			CH_4	1.41	1.43
			N_2O	2.08	2.11
06V801	06V801	Hydrogen Flare	CO_2	2,199	2,225
			CH_4	0.87	0.88
			N_2O	1.29	1.30
06V801-MSS	06V801-MSS	Hydrogen Flare MSS	CO_2	14,644	14,820
06V802	06V802	Ammonia Flare	CO_2	2,199	2,225
			CH_4	0.87	0.88
			N_2O	1.29	1.30
06V802-MSS	06V802-MSS	Ammonia Flare MSS	CO_2	9.07	9.17
FUG-PSA	FUG-PSA	Fugitives - PSA Offgas	CO_2	8.13	8.23
			CH_4	46.65	47.21
FUG-HBOG	FUG-HBOG	Fugitives - High-Btu Offgas	CO_2	0.17	0.17
			CH_4	3.16	3.20
FUG-NG	FUG-NG	Fugitives - Natural Gas	CO_2	0.29	0.29
			CH_4	1,053	1,065.70

EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ - 10153 (Revised 04/08) Table 1(a)
This form is for use by sources subject to air quality permit requirements and
may be revised periodically. [APDG 5178 v5]

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	Sep-13	**Permit No.:**		**Regulated Entity No.:**	RN102663671
Area Name:	Combined Hydrogen/Ammonia Unit			**Customer Reference No.:**	CN602582231

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 EPN			5. Building Height (Feet)	6. Height Above Ground (Feet)	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) NAME	Zone	East (Meters)	North (Meters)			(A) Diameter (Feet)	(B) Velocity (fps)	(C) Temperature (°F)	(A) Length (ft.)	(B) Width (ft.)	(C) Axis Degrees
03V901	03V901	Steam Methane Reformer	14	699413	3173268		262	13.1	63.9	287			
03V901-MSS	03V901-MSS	Steam Methane Reformer MSS	14	699413	3173268		262	13.1	61.6	260			
08B001	08B001	NH3 Start-up Heater	14	699382	3173204		103	4.1	34.2	1526			
06V801	06V801	Hydrogen Flare	14	699434	3173208		340	3.0	65.6	1832			
06V801-MSS	06V801-MSS	Hydrogen Flare MSS	14	699434	3173208		340	3.0	65.6	1832			
06V802	06V802	Ammonia Flare	14	699363	3173157		220	2.7	65.6	1832			
06V802-MSS	06V802-MSS	Ammonia Flare MSS	14	699363	3173157		220	2.7	65.6	1832			
FUG-PSA	FUG-PSA	Fugitives - PSA Offgas	14	699435	3173215		23				166	79	-37.7
FUG-HBOG	FUG-HBOG	Fugitives - High-Btu Offgas	14	699421	3173250		85				355	116	-37.7
FUG-NG	FUG-NG	Fugitives - Natural Gas	14	699340	3173135		44				470	290	-37.7

EPN = Emission Point Number

FIN = Facility Identification Number

TCEQ - 10153 (Revised 04/08) Table 1(a)
This form is for use by sources subject to air quality permit requirements and
may be revised periodically. [APDG 5178 v5]

2.3. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REVIEW

INVISTA is submitting an application to authorize installation of new equipment including a steam methane reformer, a start-up heater, two flares, and fugitive components. As defined under the U.S. EPA GHG Tailoring Rule, the proposed project will constitute a major modification for GHG emissions. Therefore EPA Region 6 is the current GHG PSD Permitting Authority for the State of Texas, and INVISTA is submitting this application to EPA Region 6 to obtain a PSD permit for GHG emission increases.

According to EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases", PSD applicability for modification at existing sources requires a two-step analysis. Further, for GHG emissions, each step requires calculation of mass-based emissions and CO_2e-based emissions. Therefore, four applicability conditions must be met for modifications at existing major sources to be subject to PSD for GHG emissions.

The four conditions are listed below

1. The CO_2e emissions increase resulting from the modification, without considering any emissions decrease, is greater than or equal to 75,000 TPY.
2. The "net emission increase" of CO_2e over the contemporaneous period is greater than or equal to 75,000 TPY
3. The GHG emission increase resulting from the modification, on a mass basis (*i.e.*, with no GWPs applied), and without considering any decreases, is greater than zero TPY.
4. The "net emissions increase" of GHG emissions on a mass basis over the contemporaneous period is greater than zero TPY.

2.4. PSD APPLICABILITY DETERMINATION

The INVISTA Victoria site has the potential to emit (PTE) GHGs, prior to the modification, greater than 100,000 TPY CO_2e and 100 TPY mass basis. As shown in the table below, the emissions increases resulting from the modification are greater than 75,000 TPY CO_2e and 0 TPY mass basis. INVISTA is basing the determination of PSD applicability on a Step 1 Analysis.

Table 2-3. PSD Applicability Summary

	GHG CO_2e Basis (TPY)	GHG Mass Basis (TPY)
Total Project Emission Increase*	1,904,380	1,903,301
GHG PSD Major Modification Threshold	75,000	0
Is GHG PSD Permitting Required?	Yes	Yes

* Detailed calculations are provided in Appendix A

2.5. BACT REVIEW

PSD regulations require Best Available Control Technology (BACT) review for all new or modified equipment. The following emission sources of GHG in the proposed hydrogen/ammonia unit are subject to BACT: reformer, start-up heater, hydrogen flare, ammonia flare, and emission points related to new fugitive components. BACT requirements are addressed in Section 3 of this application.

3. BEST AVAILABLE CONTROL TECHNOLOGY

3.1. INTRODUCTION

GHG emissions increases from the combined hydrogen/ammonia unit, expressed as carbon dioxide equivalents (CO_2e), are projected to be greater than 75,000 tons which triggers PSD permitting obligations as described in EPA's Greenhouse Gas Tailoring Rule. Pursuant to EPA regulation, the project is subject to regulation under PSD and the required BACT review has been conducted for GHG pollutants from each of the emissions sources. In the proposed project, specified GHGs will be emitted from the following sources:

- Reformer (EPN 03V901 and 03V901-MSS) - CO_2, N_2O and CH_4
- Start-up Heater (EPN 08B001) - CO_2, N_2O and CH_4
- Flares: H_2 Flare (EPN 06V801 and 06V801-MSS) and NH_3 Flare (EPN 06V802 and 06V802-MSS) - CO_2, N_2O and CH_4
- Fugitive Emissions: PSA Tailgas Fugitives (EPN FUG-PSA), High-Btu Offgas Fugitives (EPN FUG-HBOG), and Natural Gas Fugitives (EPN FUG-NG) - CO_2, CH_4

CO_2, CH_4, and N_2O will be generated as a result of hydrocarbon combustion within the reformer, start-up heater, and at the flares. CO_2 and CH_4 will also be emitted as fugitive emissions.

The GHG BACT evaluation for the proposed project was conducted in accordance with EPA regulations and the following US EPA guidance documents:

- PSD and Title V Permitting Guidance For Greenhouse Gases (hereafter referred to as General GHG Permitting Guidance)[3]
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boiler (hereafter referred to as GHG BACT Guidance for Boilers)[4]
- "Assessment of Hydrogen Production With CO_2 Capture Volume 1: Baseline State-of-the-Art Plants", DOE/NETL-2010/1434, August 30, 2010.[5]

To complete the GHG BACT evaluation, INVISTA also reviewed and/or relied on a number of other resources. Some of those resources form much of the basis for this BACT analysis. Examples of the variety of those resources which were consulted are listed below while others are indicated throughout this document:

- NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, 1990[6]
- RBLC database[7]
- Report of the Interagency Task Force on Carbon Capture and Storage, August 2010.[8]
- The National Energy Technology Laboratory guidance, "Estimating Carbon Dioxide Transport and Storage Costs", DOE/NETL-400/2010/1447, March 2010.[9]

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[3] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: March 2011). http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

[4] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf

[5] http://www.netl.doe.gov/energy-analyses/pubs/H2_Prod_Vol1_2010.pdf

[6] http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf

[7] http://cfpub.epa.gov/RBLC/

[8] http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf

[9] http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&PubId=338

3.2. BACT TOP-DOWN APPROACH

3.2.1. Step 1 - Identify Control Technologies

In this step, available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. The selected control technologies vary widely depending on the process technology and pollutant being controlled. The application of demonstrated control technologies in other similar source categories to the emission unit in question may also be considered in this step.

The following resources are typically consulted when identifying potential technologies for criteria pollutants:

1. EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database; [10]
2. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;
3. Engineering experience with similar control applications;
4. Information provided by air pollution control equipment vendors with significant market share in the industry; and/or
5. Review of literature from industrial, technical, government, academic and trade organizations.

3.2.2. Step 2 - Eliminate Technically Infeasible Options

In this step, the permitting authority eliminates "technically infeasible" control options from the list of "potentially available" control options. A control option is "technically feasible" if it has been "demonstrated" or if it is *both* "available" and "applicable."

Demonstrated control technologies. A control option is "demonstrated" if it "has been installed and operated successfully on the type of source under review."[11] A control technology that is "demonstrated" is "technically feasible" for purposes of top-down Step 2 "unless source-specific factors exist and are documented to justify technical infeasibility."[12] The NSR Manual states: "This step should be straightforward for control technologies that are demonstrated—if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible."[13]

Available control technologies. The NSR Manual describes an "available" technology as follows:

> A control technique is considered available . . . if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review.[14]

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[10] http://cfpub.epa.gov/RBLC/

[11] ENVT'L PROT. AGENCY, NSR WORKSHOP MANUAL (DRAFT), PREVENTION OF SIGNIFICANT DETERIORATION (PSD) AND NONATTAINMENT NEW SOURCE REVIEW (NNSR) PERMITTING at B.17 (October 1990) [hereinafter "NSR Manual"].

[12] *Id.* at B.21.

[13] *Id.* at B.17.

[14] *Id.* at B.18.

Particularly in the area of Carbon Capture and Sequestration (CCS), analyzed below, it is important to note that emerging control technology installations designed primarily for research and development, or as demonstration projects for a particular process unit, do not represent technologies that are necessarily both available and applicable to all similar process units.

The NSR Manual also states "availability" is fact specific:

> [T]he applicant should make a factual demonstration of infeasibility based on commercial unavailability and/or unusual circumstances which exist with application of the control to the applicant's emission units. Generally, such a demonstration would involve an evaluation of the pollutant-bearing gas stream characteristics and the capabilities of the technology.[15]

Applicable control technologies. The NSR Manual describes an "applicable" control technology as follows:

> Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (*e.g.*, is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the pollutant-bearing gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary.
>
> For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique had been applied previously. Absent an explanation of unusual circumstances by the applicant showing why a particular process cannot be used on the proposed source the review authority may presume it is technically feasible.[16]

With respect to the applicability of GHG controls, EPA provided additional guidance in 2011.[17] With respect to carbon capture and sequestration (CCS), EPA wrote:

> EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage. . . . Based on these considerations, a permitting authority may conclude that CCS *is not applicable* to a particular source, and consequently not technically feasible, even if the type of equipment needed

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[15] *Id.* at B.19.

[16] *Id.* at B.18.

[17] ENVT'L PROT. AGENCY, PSD AND TITLE V PERMITTING GUIDANCE FOR GREENHOUSE GASES, EPA-457/B-11-001 (March 2011) [hereinafter, "GHG Guidance"].

> to accomplish the compression, capture, and storage of GHGs are determined to be generally available from commercial vendors.[18]

A recent decision of EPA's Environmental Appeals Board illuminates the interplay between the concepts of "demonstrated" and "available and applicable" in the context of a GHG PSD permit. In the case of *In re: Pio Pico Energy Center*,[19] the permitting authority defined the "source type" under review narrowly for purposes of the Step 2 "demonstrated" analysis, concluded that the proposed control technology was not demonstrated for that source type, and then conducted an availability/applicability analysis. In response to a challenge to the narrow definition of source type used by the permitting authority, the EAB wrote:

> The fact that a step 2 technical feasibility analysis has two parts is an important consideration in determining what the appropriate scope for selecting "source type" should be. Because the analysis is two-fold, if the permitting authority concludes that a control technology is not "demonstrated," the inquiry does not end there. Thus, even if "source type" is defined on the narrower side of the spectrum, the permitting authority will still need to consider whether that control technology is "available" and "applicable." Defining "source type" more narrowly does not, therefore, allow applicants or permit issuers to pave an "automatic BACT off-ramp" for a control technology . . . . It merely places the control technology into the second part of the step 2 analysis, where the applicant and permit issuer will have to perform a detailed assessment of the technology's availability and applicability.
>
> Conversely, if "source type" is defined too broadly, a control technology will automatically be shunted into steps 3 and 4, thereby bypassing the detailed consideration of its technical feasibility that part 2 of step 2 would have required. Because step 4 considerations do not typically include technical feasibility, a control technology that is not truly feasible for a particular source could end up being inappropriately selected as the top control option in step 5.
>
> The present case demonstrates how the two-part step 2 analysis works. Here, even though the Region concluded that [the proposed controls] were not a ""demonstrated" control technology, the Region still performed a detailed consideration of [the proposed controls] in its "applicability" determination. [20]

Relying on this two-part structure of the Step 2 analysis, the EAB concluded that defining the source type somewhat narrowly for purposes of the "demonstrated" analysis is not fatal to the top-down approach, because the availability/applicability step will "recapture" technologies that may fall out at the "demonstrated" stage. The structure of the Step 2 analysis will be compromised only where the narrowness of the source category definition is unfair—for example, when the source under review becomes a "category of one."

3.2.3. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

All remaining technically feasible control options are ranked based on their overall control effectiveness for the pollutant under review.

Collateral effects are usually not considered until step four of the five step top-down BACT analysis and could result in rejection of a favorable control option at step 3. As a result, top-down BACT does not necessarily drive an integrated manufacturing site to lowest emissions of GHG, and particularly CO_2. For example, a carbon dioxide capture system is a large energy user. That energy is most often supplied by a fossil fuel powered energy source.

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[18] *Id.* at 36 (emphasis added).

[19] 2013 WL 4038622, PSD App. Nos. 12-04, 12-05, and 12-06 (Envt'l App. Bd., Aug. 2, 2013).

[20] *Id.* § VIII(E)(4)(b).

As a result, that power source generates CO_2, partially offsetting the amount captured. INVISTA has identified several instances in which careful consideration of collateral effects are warranted. Those instances are presented within this document to clearly indicate where the collateral effects have influenced the evaluation.

3.2.4. Step 4 - Evaluate Most Effective Controls and Document Results

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration, it is selected as the basis for the BACT limit. Alternatively, in the judgment of the permitting agency, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is selected.

With regard to CCS, EPA recognizes in its BACT guidance for GHGs that "[e]ven if not eliminated at Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible."[21] Moreover, EPA recognizes:

> With respect to the evaluation of the economic impacts of GHG control strategies, it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner. For instance, when evaluating the cost effectiveness of CCS as a GHG control option, if the cost of building a new pipeline to transport the CO_2 is extraordinarily high and by itself would be considered cost prohibitive, it would not be necessary for the applicant to obtain a vendor quote and evaluate the cost effectiveness of a CO_2 capture system. As with all evaluations of economics, a permitting authority should explain its decisions in a well-documented permitting record.[22]

Note that the GHG BACT assessment presents a unique challenge with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (*e.g.*, flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (*i.e.*, CH_4) results in a simultaneous increase in emissions of another GHG (*i.e.*, CO_2).

Permitting authorities have historically considered the effects of multiple pollutants in the application of BACT as part of the PSD review process, including the environmental impacts of collateral emissions resulting from the implementation of emission control technologies. To clarify the permitting agency's expectations with respect to the BACT evaluation process, states have sometimes prioritized the reduction of one pollutant above another. For example, technologies historically used to control NO_x emissions frequently caused increases in CO emissions. Accordingly, several states prioritized the reduction of NO_x emissions above the reduction of CO emissions, approving low NO_x control strategies as BACT that result in elevated CO emissions relative to the uncontrolled emissions scenario. In this BACT analysis, there are instances of weighing the effectiveness of a control in reducing a GHG emission against the collateral impacts of that control.

According to 40 C.F.R. §52.21(b)(49)(ii), CO_2e emissions must be calculated by scaling the mass of each of the six GHGs by the gas' associated global warming potential (GWP), which is established in Table A-1 to Subpart A of 40 C.F.R. Part 98. Therefore, to determine the most appropriate strategy for prioritizing the control of CO_2 and CH_4 emissions, INVISTA considered each component's relative GWP. As presented in Table 2-1, the GWP of CH_4 is 21

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[21] GHG Guidance at 17

[22] *Id.* at 42. *Accord In re: City of Palmdale*, 2012 WL 4320533 § VII(B)(2)(b), PSD App. No. 11-07 (Envtl. App. Bd. Sep. 17, 2012) (recognizing EPA's different treatment of cost-effectiveness in GHG contexts by noting the acceptability of a less rigorous or qualitative comparison of the capital costs of CCS and the capital costs of the proposed project).

times the GWP of CO_2. Therefore, one ton of atmospheric CH_4 emissions has the same predicted global warming effect of 21 tons of CO_2e emissions. On the other hand, one ton of CH_4 that is combusted to form CO_2 emissions prior to atmospheric release equates to 2.7 tons of CO_2e emissions. Since the combustion of CH_4 decreases GHG emissions by approximately 87 percent on a CO_2e basis, combustion of CH_4 is preferential to direct emission of CH_4.

3.2.5. Step 5 - Select BACT

In the final step, the BACT emission limit is determined for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (*i.e.*, defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology.

NAAQS have not been established for GHGs and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Since localized short-term health and environmental effects from GHG emissions are not recognized, this BACT evaluation relies on technical feasibility, control effectiveness, and determinations of costs.

3.3. REFORMER GHG BACT (EPN 03V901 AND 03V901-MSS)

The reformer will emit the following GHG pollutants: CO_2, CH_4, and N_2O. CO_2 is formed during combustion processes as the carbon in the fuel combines with oxygen. CH_4 is also formed in combustion with carbon in the fuel that does not convert to CO_2. N_2O is formed during combustion and is minimized when combustion temperatures are higher and excess oxygen is low.[23]

3.3.1. Identification of Potential GHG Control Technologies (Step 1)

INVISTA used a combination of published resources and general knowledge of industry practices to generate a list of potential controls for GHG emissions resulting from the reformer operation; these are presented in Table 3-1. Relevant RBLC search results are provided in Appendix C.

Table 3-1. Summary of Potential GHG Emission Reduction Measures

GHG Emission Reduction Measure	Description
Carbon Capture and Sequestration (CCS)	CCS includes CO_2 capture and/or compression, transport, and storage. CO_2 would be captured from the reformer process stream (shifted syngas stream) using methyl diethanolamine (MDEA) and from the reformer stack using monoethanolamine (MEA). The MDEA unit captures 95% of the CO_2 from the syngas stream, while the MEA unit captures 70% of the CO_2 from the stack gas, resulting in an overall CO_2 capture of 90%.[24]

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[23] U.S. EPA, AP-42 Section 1.4, *Natural Gas Combustion*, July 1998.

[24] U.S. Department of Energy National Energy Technology Laboratory (NETL) "Assessment of Hydrogen Production with CO_2 Capture Volume 1: Baseline State-of-the-Art Plants," August 30, 2010.

GHG Emission Reduction Measure	Description
Alternative Fuels	The potential on-site reduction in CO_2 emissions that may be realized by switching from a traditional fossil fuel to a biomass fuel is based on the specific emission factor for the fuel as related to its caloric value. Pure biomass fuels include animal meal, waste wood products and sawdust, landfill gas and sewage sludge.
Design Energy Efficiency Measures	Measures that may be included in the design of the reformer to increase combustion efficiency or enhance the recovery of available heat energy.
Operational Energy Efficiency Measures	Methods of operating the reformer so as to maintain optimal energy efficiency and energy recovery.

Energy efficiency measures have the potential to reduce CO_2, CH_4, and N_2O emissions from the reformer by reducing fuel usage. The available design and operational energy efficiency measures are outlined in the tables below.

Table 3-2. Potential Design Energy Efficiency Measures

Design Energy Efficiency Measures	Description
Process Integration and Process Control	Process integration is an efficiency analysis method wherein heating and cooling needs throughout the plant are matched with sources of the same. Process integration that is used both in the design phase as well as the operational phase of the project can minimize energy consumption. Advanced process control systems can be installed to allow the production process to be more efficient by supporting control strategies adapted to specific operating scenarios.
Minimize excess air	Larger volumes of nitrogen absorb more heat, thereby decreasing energy efficiency. Some excess air must be present to ensure complete combustion. Energy efficient burners can minimize excess air by providing the proper air-to-fuel mixture throughout the full range of firing rates, without constant adjustment.
Air preheating (economizers and air heaters)	By capturing and reusing the flue gas to preheat the combustion air, fuel usage requirements are reduced. However, air preheating will result in higher NO_x emissions due to increased flame temperature.
Rearrange the convection coils and add additional surface area	Convection coils can be rearranged and additional surface area can be added to increase heat conservation.
Low temperature desulfurization	Using desulfurization catalysts that operate at a lower temperature can use low temperature steam to heat the feed gas, instead of direct firing, which reduces NO_x emissions from the unit.
Hydrogen recovery from purge gas of ammonia synthesis loop	Purge gas must be extracted from the ammonia synthesis loop to remove inerts from the process. Various technologies including cryogenic separation, membrane technology, and pressure swing absorption can be used to recover and purify hydrogen while reducing energy loss.

Table 3-3. Potential Operational Energy Efficiency Measures

Operational Energy Efficiency Measures	Description
Good Combustion Practices	Good combustion practices include periodic burner tuning, proper equipment maintenance and operation, good fuel/air mixing in combustion zone, proper fuel gas supply system design and operation, and sufficient excess air. These measures will increase efficiency. Because GHG emissions are a direct result of the amount of fuel fired (for a given fuel), the more efficient the process, the less fuel is required, which results in less GHG emissions. As well as increasing efficiency, good combustion practices will ensure complete combustion, minimize instability of fuel gas during load changes, and increase the life of the reformer.

3.3.2. Eliminate Technically Infeasible Options (Step 2)

3.3.2.1. Carbon Capture and Sequestration

In its 2011 GHG Guidance, EPA stated:

> Assuming CCS has been included in Step1 of the top-down BACT process . . . it now must be evaluated for technical feasibility in Step 2. CCS is composed of three main components: CO_2 capture and/or compression, transport, and storage. CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review. Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (*e.g.*, space for CO_2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options).[25]

TECHNICAL FEASIBILITY OF CARBON CAPTURE AND COMPRESSION

Carbon capture and compression is not a demonstrated technology. As previously stated, a control option is "demonstrated" if it "has been installed and operated successfully on the type of source under review."[26] The type of source here under review is a privately-financed, combined hydrogen-ammonia unit with a steam methane reformer (SMR) that will emit approximately two million tons per year of CO_2e, and which will be designed to achieve a very high level of reliability between four-year planned maintenance turnarounds. The high reliability is a critical design feature of the project, as the reliability must be high enough to justify the project.

In our review of the relevant technical documents, we have been unable to find another privately-financed, large volume source on which carbon capture and compression has been installed and successfully operated with high reliability, over a thirty year life of the project. In the facility that most closely resembles the Project, Air Products in Port Arthur, Texas has installed carbon capture and compression at two SMRs located at the Valero Port Arthur

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[25] GHG Guidance at 36.

[26] NSR Manual at B.17.

Refinery as part of a National Energy Technology Laboratory (NETL) demonstration project.[27] There are, however, significant differences between the INVISTA Project and the Air Products demonstration project.

First and foremost, carbon capture and compression system at the Air Products facility in Port Arthur was installed not due to a BACT determination, but as part of a Department of Energy (DOE) research and development project. The Air Products project design basis is only for a three year trial run, until September 2015,[28] after which Air Products has no obligation to continue operation of the system.

Further, the Air Products carbon capture and compression demonstration facilities have only commenced operations in early 2013, as such it has not yet demonstrated the high reliability required by the INVISTA Project. In comparison, the INVISTA Project would require that carbon capture and compression operate with a very high degree of reliability over the multi-decade life of the Project. The level of reliability and length of operation required by the INVISTA Project have not been demonstrated.

Second, the Air Products project has no enforceable emission limitation on the amount of CO_2 that could be emitted into the atmosphere in the event of the unavailability of a capture or compression system. On the other hand, a determination that carbon capture and compression is BACT for the INVISTA Project would result in the imposition of stringent, continuous emission limitations. Where carbon capture and compression technology has not yet been installed and operated successfully at a similar source type in a situation that includes at least some level of enforceable emission limitations, the technology cannot be described as "demonstrated."

Last, the majority of the cost of the Air Products project is funded by the DOE.[29] On the other hand, the INVISTA Project will be entirely privately financed. Significant public financing of all the operating projects in the United States that capture and compress large volumes of anthropogenic CO_2 shows that there is still significant project-related risk (*i.e.*, risk that carbon capture and compression at these volumes may not be operated successfully over the long term at regulatory levels of reliability) that must be borne by public financing.

Another demonstration project, the Archer Daniels Midland CCS demonstration project in Decatur, Illinois, has not demonstrated carbon capture and compression at sufficiently high volumes (317,000 tons per year demonstrated) to conclude that the technology in use there is applicable to the INVISTA Project (1.7 Million tons per year design).

Altogether, these considerations support the conclusion that carbon capture and compression technology is not demonstrated for privately-financed, large volume sources that demand high reliability like INVISTA's.

Carbon capture and compression is a generally available technology. Monoethanolamine (MEA) and Monodiethanolamine (MDEA) systems by which CO2 may be captured from the reformer process and reformer stack, along with large-scale CO2 compressors are generally available from commercial vendors. Accordingly, INVISTA concludes that these are available technologies.

Carbon capture and compression is not an applicable technology. As discussed above in Section 3.2, EPA states:

> "Based on these considerations, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment

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[27] http://www.netl.doe.gov/publications/factsheets/project/FE0002381.pdf.
[28] *Id.*
[29] *Id.*

> needed to accomplish the compression, capture, and storage of GHGs are determined to be generally available from commercial vendors."[30]

In the case of the INVISTA Project, despite the general availability of the components necessary to capture and compress CO_2 from the reformer process and reformer stack, as shown above CCS has not been demonstrated for sources such as this, making the technology not applicable.

Another important aspect of applicability set forth in EPA's GHG Guidance is whether the volume of gas streams to be controlled differ so significantly from previous applications that it is uncertain that the control device will work in the project under review. As discussed above, the Air Products facility has just commenced operation and has not developed a multi-year operational record upon which INVISTA could conclude that large-scale carbon capture and compression would support highly reliable operations of its SMR over the four-year periods between scheduled maintenance turnarounds.

For these reasons, carbon capture and compression is not applicable as a control technology for the INVISTA Project.

TECHNICAL FEASIBILITY OF CO_2 STORAGE

Permanent geological sequestration of CO_2 is not a demonstrated technology. The National Energy Technology Laboratory's 2012 Carbon Utilization and Storage Atlas[31] identifies three large-scale CO_2 injection projects in the United States and Canada at which CO_2 injection is ongoing, only one of which is a non-Enhanced Oil Recovery (EOR) sequestration project (Illinois Basin—Mt. Simon Sandstone).[32] Of the planned projects, only the Kevin Dome project in Montana is a non-EOR storage project. Importantly, none of the active (or planned) injection sites have demonstrated the capability to accept the volume of CO_2 expected from this project. In fact, the largest active injection site (SECARB's Cranfield EOR Field) has a total capacity of only 3.4 million metric tons.

Furthermore, NETL describes these sites as being evaluated to "validate" the hypothesis that carbon capture, use, and sequestration can be conducted at a commercial scale. The challenges to deployment of these sites for large-scale permanent sequestration are numerous and significant. NETL describes the following aspects to its ongoing research:

- Whether there is adequate injectivity and available capacity at near-commercial scale by injecting CO_2 over an extended period of time;
- Verify storage permanence, including ensuring that project do not adversely impact underground sources of drinking water or cause CO_2 to be released into the atmosphere;
- Determine the areal extent of potential release pathways;
- Develop risk assessment strategies with respect to potential releases of CO_2; and
- Develop information that supports the development of an effective regulatory and legal framework for safe, long-term injection and geologic CO_2 storage.[33]

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[30] GHG Guidance at 36.

[31] *See* http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIV/Atlas-IV-2012.pdf.

[32] Though the NETL report identifies geologic formations on the Gulf Coast that *could* sustain geologic sequestration of CO_2, it would be entirely speculative for INVISTA to acquire rights to such formations, conduct the necessary research and development to assess their suitability for sequestration, develop the injection and monitoring systems, and resolve the outstanding transport, fate, and potentially adverse human health and environmental impacts from CO_2 storage. Accordingly, INVISTA has not included a detailed analysis of such a speculative control technology.

[33] *Id.* at 11.

Because of the injection volume limitations of these projects, along with the uncertainty associated with the fate of CO_2 so injected, long-term geologic sequestration has not been successfully applied to the type of source under review in this application (*i.e.*, a high-volume, privately-financed, anthropogenic CO_2 source requiring a highly reliable CCS system). Accordingly, permanent geological sequestration is not a demonstrated technology for purposes of the application.

Permanent geological sequestration of CO_2 is not an available technology. The large-scale CO_2 storage projects identified by NETL have not yet reached the licensing and commercial stage of development. Indeed, these projects are being undertaken in public-private partnership arrangements, with significant financial support being provided by the Department of Energy. Moreover, the stated purpose of the large-scale projects is to "validate that CCUS can be conducted at a commercial scale."[34] In fact, the relatively small storage capacities of these projects (the largest of which is only 3.4 million metric tons) suggests that they are being conducted at a pilot scale, relative to the volume of CO_2 that would be emitted by INVISTA's Project. Technologies in the pilot scale testing stages of development are not considered "available" technologies. Because these pilot scale projects have not yet reached the licensing and commercial stage of development, permanent geological sequestration of CO_2 is not an available technology.

Permanent geological sequestration of CO_2 is not an applicable technology. The large-scale CO_2 storage projects identified by NETL are incapable of accepting the large volumes of CO_2 that would be produced by the INVISTA Project. NETL itself is assessing whether these projects have capacity to reliably store CO_2 long-term without adverse human health or environmental impacts, and so without firm findings and conclusions in this area, INVISTA cannot rely on these projects to provide permanent sequestration of its CO_2.

Some of the NETL projects involve sequestration of CO_2 in EOR applications. While such projects are undoubtedly important in researching the feasibility of carbon capture, use, and sequestration, there are significant issues surrounding CO_2 ownership, short- and long-term monitoring, the type of injection wells to be used in EOR applications, and the permanence of sequestration in these fields.

Furthermore, one of the key economic drivers for the Project is its need for very highly reliable air pollution control systems. Any sequestration option that cannot reliably guarantee the acceptance of some 1.9 million tons per year of CO_2 will have profound impacts on the economics of the Project. Accordingly, it is important to note that INVISTA is unaware of any user of CO_2 for enhanced oil recovery that is, at this time, willing to provide INVISTA firm pricing for a highly-reliable, 30-year commitment to accept approximately 2 million tons per year of CO_2 from the Project. Without such a commitment, EOR sequestration of CO_2 is not demonstrated, not available and therefore not applicable to the Project.

TECHNICAL FEASIBILITY OF CO_2 TRANSPORTATION

CO_2 transportation to permanent geological sequestration sites is not a demonstrated technology. For the source type here under review (*i.e.*, a high-volume, privately-financed, anthropogenic CO_2 source requiring a highly reliable CCS system), there is no CO_2 pipeline that has been installed and operated successfully connecting a high volume anthropogenic CO_2 source to a permanent geologic sequestration site with sufficient capacity to reliably accept such volumes. And even if such a hypothetical pipeline were to be identified, it certainly has not been successfully operated in such a way as to support highly-reliable operation of the anthropogenic source, particularly a source subject to stringent, continuous CO_2 emission limitations.

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[34] *Id.*

CO_2 transportation to permanent geological sequestration sites is an available technology. Materials to construct pipelines capable of reliably transporting large volumes of CO_2 are generally available from commercial vendors. Accordingly, INVISTA concludes that CO_2 pipelines are an available technology.

CO_2 transportation to permanent geological sequestration sites is not an applicable technology. The inescapable fact is that because there are no technically feasible, large-capacity, reliable, permanent geological sequestration sites, any CO_2 pipeline from INVISTA's proposed facility would be a "pipeline to nowhere." Moreover, even if one of the large-scale carbon sequestration projects in NETL's 2012 Atlas were hypothetically capable of serving the INVISTA facility, the logistical hurdles of constructing, owning, and operating a high-capacity CO_2 pipeline to one of those sites are high. For example, the closest non-EOR sequestration site noted by NETL would be the Mt. Simon Sandstone project in Illinois, some 1,000 miles away. Issues such as obtaining contracts for offsite land and right of way acquisitions (including the availability of land) and the timing of when the new pipeline would be available relative to the startup of the proposed project would be extraordinarily difficult to overcome. Moreover, INVISTA is unaware of any user of CO_2 for enhanced oil recovery that is, at this time, willing to provide INVISTA firm pricing for a highly-reliable, 30-year commitment to accept approximately 2 million tons per year of CO_2 from the Project. Without such a commitment, even transportation to EOR-based injection of CO_2 is not applicable to the Project.

TECHNICAL FEASIBILITY OF CARBON CAPTURE, COMPRESSION, TRANSPORTATION, AND STORAGE

Assessed individually, carbon capture, compression, transportation, and permanent geological sequestration of CO_2 are technically infeasible. Assessed together as suggested in EPA's GHG Guidance,[35] there is no question that CCS is neither demonstrated, nor available and applicable to the type of source here under review. Accordingly, INVISTA concludes that CCS is technically infeasible as a BACT control. Nevertheless, INVISTA will voluntarily include a hypothetical, best-case, Step 4 cost-effectiveness analysis for CCS in this application.

3.3.2.2. Use of Alternative Fuels

EPA has not required applicants to change the "fundamental scope" of the project in considering what is "available."[36] Natural gas is the lowest GHG-emitting fossil fuel that could be used for this reformer, which requires a gaseous fuel. INVISTA is also proposing to utilize a vent gas stream as an additional fuel stream for the reformer. The use of this vent gas stream (High BTU off-gas) for energy recovery increases the overall energy efficiency of the INVISTA Victoria facility. Additionally, natural gas serves as the ammonia process feedstock, and the simultaneous production of steam and conversion of several natural components for ammonia production is a fundamental aspect of the production process. Consequently, using alternative fuels and raw materials for the reformer would disrupt the basic business purpose for the proposed hydrogen/ammonia unit. Therefore, alternative fuel firing with a lower carbon impact is inherently infeasible for the reformer.

3.3.2.3. Design Efficiency Measures

All of the design energy efficient measures listed in above are considered to be technically feasible.

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[35] GHG Guidance at 36 ("Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source.").

[36] Old Dominion 3 E.A.B. 779 (1992)

3.3.2.4. Operational Energy Efficiency Measures

All of the operational energy efficient measures listed in above are considered to be technically feasible.

3.3.3. Rank Remaining Control Technologies (Step 3)

Of the control technologies that passed through Step 2, it is determined in Step 3, if technically feasible, CCS would be the most effective control of CO_2 emissions at 90% control (if a permanent sequestration option did exist), followed by energy efficiency measures.

3.3.4. Evaluation of Most Stringent Controls (Step 4)

The remaining control options are evaluated starting with the most effective potential control option, carbon capture and storage.

3.3.4.1. Carbon Capture and Storage

Given the finding that CCS is technically infeasible, an evaluation of economic feasibility under Step 4 of the top-down BACT analysis is not required. INVISTA does, nonetheless, offer the following evaluation voluntarily.

For the reasons set out above in Section 3.3.2.1, neither transportation of CO2 to a permanent geological sequestration site nor transportation of CO2 to an enhanced oil recovery (EOR) facility to be developed and operated by INVISTA is, at this time, capable of economic evaluation for this Project in any but the most speculative terms. Also for the reasons set above, transportation of CO2 to Denbury Resources' Hastings Field for EOR by way of Denbury's Green Line CO2 pipeline is only slightly less speculative. Nevertheless, because Denbury operates an actual EOR field, INVISTA can estimate the hypothetical costs of carbon capture, compression, and transportation to an interconnection with the Green Line. It is important also to note that a connection to the Green Line is the hypothetical best-case economic analysis for CCS; any connection to permanent geologic sequestration, other EOR, or INVISTA-developed EOR—currently unavailable to the Project—would be more costly. The next nearest hub for CO2 pipeline to EOR is the Denver City Hub, located approximately 350 miles from the INVISTA, Victoria site. The nearest active permanent geologic sequestration site is approximately 1000 miles away near Decatur, Illinois, with no pipeline access from the Gulf Coast and insufficient capacity to serve the INVISTA Project.

INVISTA has estimated the capital costs associated with carbon capture and compression from the reformer process stream and reformer stack using the U.S. Department of Energy National Energy Technology Laboratory (NETL) document "Assessment of Hydrogen Production with CO_2 Capture Volume 1: Baseline State-of-the-Art Plants."[37] That study utilizes two different removal methods—MEA and MDEA—for capturing CO_2 from the reformer stack and from the reformer process stream respectively.

INVISTA has estimated the capital costs associated with the transportation of CO_2 from the Project to Denbury's Green Line, some 120 miles away from the Project, and also to the Denver City Hub, approximately 350 miles away from the Project. INVISTA used the NETL guidance entitled "Estimating Carbon Dioxide Transport and Storage Costs"[38] to estimate the costs of CO_2 transportation.

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[37] "Assessment of Hydrogen Production With CO_2 Capture Volume 1: Baseline State-of-the-Art Plants" DOE/NETL-2010/1434, August 30, 2010.

[38] DOE/NETL-400/2010/1447, March 2010, http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&PubId=338.

Due to routing to an existing CO_2 pipeline, permanent geologic storage capital costs of approximately $60 million have not been included in this economic analysis. A detailed capital cost analysis is provided in Appendix B.

Capital Costs

The capital cost of CO_2 capture, compression, and transport to the Denbury pipeline has been estimated at $740 million, including $500 million for carbon capture and compression, and $240 million for transport. The total capital cost would exceed the approximately $600 million capital cost of the entire hydrogen/ammonia unit.

The capital cost of CO_2 capture, compression, and transport to the Denver City Hub has been estimated at $1.27 billion, including $500 million for carbon capture and compression, and $770 million for transport. The total capital cost would exceed the approximately $600 million capital cost of the entire hydrogen/ammonia unit.

Economic Infeasibility

Because of the high absolute capital cost of CCS and the high capital cost of CCS relative to the capital cost of the Project, the Project would not be constructed if CCS were selected as BACT. Therefore, consistent with EPA's NSR Manual, GHG Guidance, and recent administrative decisions set forth in more detail in Section 3.2.4, CCS is not an economically feasible control option for the Project.

Energy and Environmental Impacts

A CCS system would also cause significant adverse energy and environmental impacts. The system used to capture CO_2 emissions would consume large amounts of energy. A large quantity of steam would be required to regenerate the solvents. Generating that steam would create additional emissions of GHGs, increase criteria air pollutants from the Project, and would consume natural gas. Also, additional water would be required for steam production and for cooling the compression systems resulting in greater water consumption and treatment.

3.3.4.2. Design Energy Efficiency Options

Process Integration and Process Control

The design of the unit has been optimized to maximize energy efficiency. The different operating scenarios are described in Section 2.1. As detailed in Section 2.1, there are three different steam production cases: maximum, normal, and minimum. The unit will operate such that steam production is maximized whenever possible, *i.e.*, heat recovery is maximized. In addition, INVISTA will use an advanced process control system, allowing the production process to be more efficient.

Minimize excess air

Energy efficient burners will be used to minimize excess air.

Air Preheating

Excessive air preheating can result in an increase in thermal NO_x emissions due to increased flame temperature. Because of this reason, optimum preheating of the air will be performed to minimize the increase in thermal NO_x emissions.

Good Design of convection coils and add additional surface area

As part of the project, the preheat coil will be designed to increase energy efficiency and throughput. This energy efficiency method is considered to be feasible and is proposed to be implemented.

Hydrogen recovery

Pressure swing absorption (PSA) will be utilized to recover hydrogen in an energy efficient manner. As well as being energy efficient, PSA also helps to produce a higher purity hydrogen product.

3.3.4.3. Operational Energy Efficiency Options

Good Combustion Practices
Oxygen monitors and intake air flow monitors will be used to optimize the fuel/air mixture and limit excess air. INVISTA will conduct periodic burner tuning and ensure proper equipment maintenance and operation.

3.3.5. Selection of GHG BACT (Step 5)

The proposed GHG BACT for the reformer consists of:

- Design energy efficiency measures
  - Process integration/ Advanced process control system
  - Heat recovery via steam generation
  - Energy efficient burner design
  - Optimal air Preheating
  - Energy efficient preheat coil design

- Operational energy efficiency measures
  - Optimizing fuel/air mix
  - Low excess air
  - Periodic burner tuning
  - Proper equipment maintenance based on manufacturer recommendations

INVISTA proposes a BACT limit for the reformer of 1,879,561 tpy CO_2e on a 365-day rolling average. A CO_2 CEMS will be used to demonstrate compliance with the emission limit.

3.4. START-UP HEATER GHG BACT (EPN 08B001)

The start-up heater will emit the following GHG pollutants: CO_2, CH_4, and N_2O. GHG formation is based on combustion of gaseous fuels, similar that described for the reformer in Section 3.3. The start-up heater is expected to be used less than 1300 hours per year.

3.4.1. Identification of Potential GHG Control Technologies (Step 1)

The control techniques identified for the start-up heater are shown in the table below. No RBLC search results were found relating to the start-up heater.

Table 3-1. Summary of Available GHG Emission Reduction Measures

GHG Emission Reduction Measure	Description
Carbon Capture and Storage	CCS includes CO_2 capture and/or compression, transport, and storage. CO_2 would have to be captured from the start-up heater stack, compressed to the required pressure, and transported to a suitable storage site.[39]

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[39] For the reasons set forth below, CCS may also not be an "available" control technology for purposes of a Step 1 analysis. Nevertheless, INVISTA voluntarily includes it as an "available" control technology, and analyzes its technical feasibility under Step 2.

GHG Emission Reduction Measure	Description
Lowest Carbon Fuel	INVISTA has selected natural gas as the fuel for the start-up heater. Natural gas has the lowest carbon intensity of any available fuel for such combustion units. Biomass cannot be used due to process design.
Design Energy Efficiency Measures	Measures that may be included in the design of the heater to increase combustion efficiency or enhance the recovery of available heat energy.
Operational Energy Efficiency Measures	Methods of operating the heater so as to maintain optimal energy efficiency and energy recovery.

Energy efficiency measures have the potential to reduce CO_2, CH_4, and N_2O emissions from the heater by reducing fuel usage. The available design and operational energy efficiency measures are outlined in the tables below.

Table 3-2. Potential Design Energy Efficiency Measures

Design Energy Efficiency Measures	Description
Minimize excess air	Heater efficiency decreases as excess air increases, because larger volumes of nitrogen absorb more heat. However, some excess air must be present to ensure complete combustion. Energy efficient burners can minimize excess air by providing the proper air-to-fuel mixture throughout the full range of firing rates, without constant adjustment.
Air Preheater	By capturing and reusing the flue gas to preheat the combustion air, fuel usage requirements are reduced. However, air preheating results in higher NO_x emissions due to increased flame temperature.
Insulation	Significant heat loss can occur through the heater shell. Proper insulation is important to keep these losses to a minimum and improve thermal efficiency. Improving thermal efficiency results in decreased supplemental natural gas requirements and decreased GHG emissions.

Table 3-3. Potential Operational Energy Efficiency Measures

Operational Energy Efficiency Measures	Description
Instrumentation & Controls	Process control technologies monitor and control heater operating parameters such as excess oxygen, carbon monoxide, pressure, combustion air flow, fuel flow, and temperature to optimize heater energy efficiency.
Reduce air leakages	Air infiltration occurs as a result of the large temperature difference between the hot combustion gases and ambient air temperature. The resulting impact of air leakage is similar to operating the heater with too much excess air; it is a source of energy loss due to the unnecessary air being heated and wasted. The sources for air leaks can range from small openings to actual cracks in heater casings or ductwork. Indicators of excessive air leakage include high O_2 levels measured at the outlet of the heater, as well as fuel consumption and gas temperatures. Good maintenance procedures in combination with operational monitoring can reduce air leakages.

Operational Energy Efficiency Measures	Description
Good Combustion Practices	In addition to the design energy efficiency measures described above, good combustion practices include periodic burner tuning, proper equipment maintenance and operation, good fuel/air mixing in combustion zone, proper fuel gas supply system design and operation, and sufficient excess air. These measures will increase efficiency. Because GHG emissions are a direct result of the amount of fuel fired (for a given fuel), the more efficient the process, the less fuel is required, and the less GHG emissions. As well as increasing efficiency, good combustion practices will ensure complete combustion, minimize instability of fuel gas during load changes, and increase the life of the heater.

3.4.2. Eliminate Technically Infeasible Options (Step 2)

Carbon Capture and Storage

There are no known installations where the post-combustion capture of CO_2 has been installed and operated successfully on natural gas-fired boilers/heaters used exclusively for start-up purposes. The start-up heater has a dilute CO_2 stream and is operated less than 1300 hours per year, so the GHG emissions are minimal. According to U.S. EPA, "an applicant is generally not required to undergo extensive delays and expense to research and test unproven technologies as part of the BACT process." Further, the agency has held that "technologies in the pilot scale testing stages of development would not be considered available for BACT review."[40]

In EPA's March 2011 GHG BACT guidance, EPA takes the position that, "for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams." However, the start-up heater does not fit into either of these categories. The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above quoted examples. However, some guidance specific to medium-sized natural gas boilers appears in its guidance document which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this EPA boiler example, carbon capture is not listed nor considered in the BACT analysis as a potentially available option. The start-up heater, with a maximum firing rate of 50 MMBTU/hr, is smaller than this EPA example.

Based on EPA's guidance, a CO_2 capture system for small to medium size combustion systems, such as the start-up heater, is not a reasonable BACT option. This is understandable because the capture of the CO_2 from the start-up heater is significantly more difficult than from the types of industrial gas streams that EPA references as having potential for CCS. The increased difficulty is due to four predominant factors: the start-up heater exhaust's low CO_2 concentration, low pressure, low quantity of CO_2 available for capture, and the high variability of load. Natural gas combustion exhaust streams have relatively low CO_2 concentrations (6-9% versus 12-15% for coal-boilers and >30% for high concentration industrial gas streams). This means that for a natural gas boiler a very large volume of gas needs to be treated to recover the CO_2. Additionally, the low concentration and low pressure complicate the absorption and desorption of the CO_2, which increases the energy required. Also, a low pressure absorption system creates a low pressure CO_2 stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO_2 capture on any natural gas combustion exhaust extremely difficult.

Based on the information reviewed for this BACT determination, INVISTA concludes that the use of post-combustion CO_2 capture is not a technically feasible option for the start-up heater.

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[40] NSR Manual at B.18.

Lowest Carbon Fuel
Use of the lowest carbon fuel available is a technically feasible option. Methane is the lowest carbon fuel available since biomass cannot be used due to the process design.

Design Efficiency Measures
All of the design energy efficient measures listed in above are considered to be technically feasible, with the exception of external insulation. Due to planned intermittent use of this source and the concern for potential corrosion under insulation (CUI), external insulation is not feasible for this source.

Operational Energy Efficiency Measures
All of the operational energy efficient measures listed in above are considered to be technically feasible.

3.4.3. Rank Remaining Control Technologies (Step 3)

As explained in Section 3.4.2, CCS is not technically feasible for the start-up heater. Nevertheless, INVISTA voluntarily ranks it here and addresses the associated economic, energy, and environmental impacts in the next section. If CCS were technically feasible, it would be the most effective control for GHG emissions with an estimated 90% CO_2 capture efficiency. The next most effective control options are lowest carbon fuel, design energy efficiency measures, and operational energy efficiency measures.

3.4.4. Evaluation of Most Stringent Controls (Step 4)

The remaining control options are evaluated starting with the most effective control option, carbon capture and storage.

3.4.4.1. Carbon Capture and Storage

Because of the matters discussed above under technical feasibility, a qualitative statement regarding cost effectiveness is sufficient: the economic cost ineffectiveness of the CO_2 stream from the reformer process and reformer stack set forth in Section 3.3.4.1 is negatively compounded by the addition of another carbon capture system that will capture only a very small amount of CO_2 (approximately 3,600 tons per year).

Economic Infeasibility
As shown in Section 3.3.4.1 for the reformer, CCS is not an economically feasible control option. The costs associated with implementing CCS for the start-up heater, comprising of the CO_2 scrubber and compressor, would be on the same scale than the costs associated with the reformer, due to the factors set forth in Section 3.4.2. Therefore CCS is not an economically feasible control technology for the start-up heater.

Energy and Environmental Impacts
A CCS system would also cause significant adverse energy and environmental impacts. The system used to capture CO_2 emissions would consume large amounts of energy. A large quantity of steam would be required to regenerate the solvents. Generating that steam would create additional emissions of GHGs, increase criteria air pollutants emissions, and would consume natural gas. Also, additional water would be required for steam production and for cooling the compression systems resulting in greater water consumption and treatment. Therefore, INVISTA has determined that CCS is not BACT for the startup heater.

3.4.4.2. Lowest Carbon Fuel

INVISTA will use natural gas to fuel the start-up heater. Natural gas has the lowest carbon intensity of any available fuel for the start-up heater.

3.4.4.3. Design Energy Efficiency Measures

Minimize Excess Air
INVISTA will use energy efficient burners to minimize excess air.

Air Preheater
Excessive air preheating may result in an increase in thermal NO_x emissions due to increased flame temperature. Based on this reason, use of an air preheater is not environmentally favorable and will not be implemented.

Insulation
INVISTA will equip the start-up heater with adequate internal insulation, e.g. refractory, to reduce heat losses.

3.4.4.4. Operational Energy Efficiency Measures

Instrumentation and Controls
The start-up heater will have instrumentation and controls to maximize thermal efficiency.

Reduce Air Leakages
INVISTA will employ good maintenance procedures in combination with operational monitoring to reduce air leakages.

Good Combustion Practices
Good combustion practices will be implemented for the start-up heater. These practices will include periodic burner tuning, good fuel/air mixing in combustion zone, proper fuel gas supply system design and operation, and optimum excess air.

3.4.5. Selection of GHG BACT (Step 5)

The proposed GHG BACT for the startup heater is:

- Selection of the lowest carbon fuel available (natural gas)
- Design energy efficiency measures:
  - energy efficient burners
  - proper insulation
- Operation efficiency measures:
  - instrumentation and controls
  - reduction of air leakages
  - periodic burner tuning
  - good fuel/air mixing in combustion zone
  - proper fuel gas supply system design and operation

INVISTA proposes a BACT limit for the start-up heater as use of low carbon fuel, natural gas, and work practice standards as identified above as BACT.

3.5. HYDROGEN FLARE GHG BACT (EPN 06V801 AND 06V801-MSS)

Flares are examples of control devices in which the control of one GHG pollutant causes collateral GHG emission of another pollutant. Specifically, the control of CH_4 in the process gas at the flare results in the creation of additional CO_2 emissions through combustion of the CH_4. However, given the relative GWPs of CO_2 and CH_4, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions. For example, combusting 1 lb of CH_4 (21 lb CO_2e) at the flare at 99% efficiency will result in 0.01 lb CH_4 and 2.72 lb

CO_2 (0.01 lb CH_4 x 21 CO_2e/CH_4 + 2.72 lb CO_2 x 1 CO_2e/CO_2 = 2.93 lb CO_2e), and therefore, on a CO_2e emissions basis, combustion control of CH4 is preferable to venting CH4 without control. In an addition to reducing CH_4 emissions, flares are an important safety device; flaring is necessary to safely and efficiently combust process gases.

The hydrogen flare utilizes continuous pilots as part of the design of the flare. MSS emissions (including H_2 during product demand changes) will be flared.

The hydrogen flare will emit the following GHG pollutants: CO_2, CH_4, and N_2O. CO_2 emissions from flaring gas streams are produced from the combustion of carbon-containing compounds (CO, VOCs, CH_4) present in the pilot fuel and MSS streams. CH_4 emissions from the flare are due to incomplete hydrocarbon combustion from the flare pilots. Minimal amounts of N_2O will also be formed during the combustion process. GHG emissions from Hydrogen Flare MSS consist of CO_2 emissions from combustion of carbon compounds within gas streams related to MSS activities.

3.5.1. Identification of Potential GHG Control Technologies (Step 1)

The following potential CO_2 control strategies for the flare were considered as part of this BACT analysis. Relevant RBLC search results are provided in Appendix C.

Table 3-4. Summary of Available GHG Emission Reduction Measures

GHG Emission Reduction Measure	Description
Use of lowest carbon fuel for pilots	Natural gas has the lowest carbon intensity of any available fuel for flares.
Flare gas recovery	Flaring can be reduced by installation of commercially available equipment to construct a recovery system, including recovery compressors, flow controls and piping systems. The recovered gas is then utilized by introducing it into the fuel system to supplement the normally used fuels, or recycled into the process.
Good flare design	Assures high reliability of flare and high destruction efficiencies. Good flare design can be employed to destroy large fractions of the flare gas. Much work has been done by flare and flare tip manufacturers to assure high reliability and high destruction efficiencies. Good flare design includes pilot flame monitoring and monitoring/control of waste gas heating value.
Good combustion practices	Good combustion practices for flares include appropriate maintenance of equipment (such as periodic flare tip maintenance) and operating within the recommended heating value and flare tip velocity as specified by its design. Although good combustion practices do not themselves necessarily directly reduce GHG emissions, using good combustion practices results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed and with consideration of other energy optimization practices.

3.5.2. Eliminate Technically Infeasible Options (Step 2)

Use of clean fuel for pilots
Natural gas is considered a technically feasible fuel for the pilots.

Flare Gas Recovery

Recovery of pilot gas is not feasible as it is required to ensure the pilots remain lit. Due to the sporadic nature of the MSS emissions controlled by the flare, it is not technically feasible to re-route MSS gases to the reformer fuel system and hence, these gases will be combusted by the flare for control. In addition, the total CO_2e emissions for the hydrogen flare are very low versus emissions from a flare at a refinery or ethylene plant. Given the relatively low GHG emissions from the hydrogen flare, it would not be cost effective to implement flare gas recovery.

Good flare design

Use of a good flare design with pilot thermocouples is a demonstrated and available option.

Good Combustion Practices

Use of good combustion practices is considered technically feasible.

3.5.3. Rank Remaining Control Technologies (Step 3)

INVISTA proposes to implement all the remaining feasible control technologies (selection of natural gas for the pilots, good flare design, and good combustion practices), so Step 3 is not necessary.

3.5.4. Evaluation of Most Stringent Controls (Step 4)

Since INVISTA proposes to implement all the technically feasible control options, Step 4 is not necessary.

3.5.5. Selection of GHG BACT (Step 5)

INVISTA proposes as BACT for the hydrogen flare:

- using natural gas for the pilots
- implementing good flare design
- following good combustion practices

INVISTA proposes a BACT limit for the hydrogen flare of the use of natural gas as the pilot fuel and thermocouple monitoring of the pilots.

3.6. AMMONIA FLARE GHG BACT (EPN 06V802 AND 06V802-MSS)

The ammonia flare utilizes continuous pilots as part of the design of the flare. Dry gas seals and MSS emissions will be flared. However, the dry gas seals streams have negligible carbon content and the MSS streams contain very low levels of carbon (*i.e.,* <1%). Therefore GHG emissions from the ammonia flare will result from mainly from pilot flaring.

The ammonia flare will emit the following GHG pollutants: CO_2, CH_4, and N_2O. CO_2 emissions from flaring gas streams are produced from the combustion of carbon-containing compounds (CO, VOCs, CH_4) present in the pilot fuel and MSS streams. CH_4 emissions from the flare are due to incomplete hydrocarbon combustion from the flare pilots. Minimal amounts of N_2O will also be formed during the combustion process.

3.6.1. Identification of Potential GHG Control Technologies (Step 1)

The following potential CO_2 control strategies for the flare were considered as part of this BACT analysis. Relevant RBLC search results are provided in Appendix C.

Table 3-5. Summary of Available GHG Emission Reduction Measures

GHG Emission Reduction Measure	Description
Use of lowest carbon fuel for pilots	Natural gas has the lowest carbon intensity of any available fuel for flares.
Flare gas recovery	Flaring can be reduced by installation of commercially available equipment to construct a recovery system, including recovery compressors, flow controls and piping systems. The recovered gas is then utilized by introducing it into the fuel system to supplement the normally used fuels, or recycled into the process.
Good flare design	Assures high reliability of flare and high destruction efficiencies. Good flare design can be employed to destroy large fractions of the flare gas. Much work has been done by flare and flare tip manufacturers to assure high reliability and high destruction efficiencies. Good flare design includes pilot flame monitoring and monitoring/control of waste gas heating value.
Good combustion practices	Good combustion practices for flares include appropriate maintenance of equipment (such as periodic flare tip maintenance) and operating within the recommended heating value and flare tip velocity as specified by its design. Although good combustion practices do not themselves necessarily directly reduce GHG emissions, using good combustion practices results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed and with consideration of other energy optimization practices.

3.6.2. Eliminate Technically Infeasible Options (Step 2)

Use of clean fuel for pilots
Natural gas is considered a technically feasible fuel for the pilots.

Flare Gas Recovery
Dry gas seals are primarily nitrogen containing streams that contain minimal carbon so it is not feasible to recover these streams and hence they will be flared. Recovery of pilot gas is not feasible as it is required to ensure the pilots remain lit. Due to the sporadic nature of the MSS emissions controlled by the flare, it is technically infeasible to re-route MSS gases to the process fuel system and hence, these gases will be combusted by the flare for control. In addition, the total CO_2e emissions for the ammonia flare are only around 2,200 tpy, whereas CO_2e emissions from a flare at a refinery or ethylene plant are typically an order or two of magnitude higher. Given the relatively low GHG emissions from the ammonia flare, it would not be cost effective to implement flare gas recovery.

Good flare design
Use of a good flare design with appropriate instrumentation and control is a demonstrated and available option.

Good Combustion Practices
Use of good combustion practices is considered technically feasible.

3.6.3. Rank Remaining Control Technologies (Step 3)

INVISTA proposes to implement all the remaining feasible control technologies (selection of natural gas for the pilots, good flare design, and good combustion practices), so Step 3 is not necessary.

3.6.4. Evaluation of Most Stringent Controls (Step 4)

Since INVISTA proposes to implement all the technically feasible control options, Step 4 is not necessary.

3.6.5. Selection of GHG BACT (Step 5)

INVISTA proposes as BACT for the ammonia flare:

- using natural gas for the pilots
- implementing good flare design
- following good combustion practices

INVISTA proposes a BACT limit for the ammonia flare of the use of natural gas as the pilot fuel and thermocouple monitoring of the pilots.

3.7. FUGITIVE EMISSIONS GHG BACT (EPN FUG-PSA, FUG-HBOG, FUG-NG)

There will be emissions of the following GHG pollutants, CO_2 and CH_4, from the PSA Offgas, High Btu Offgas and Natural Gas fugitive components at the site.

3.7.1. Identification of Potential GHG Control Technologies (Step 1)

The following potential control strategies for the fugitive emissions were considered as part of this BACT analysis. Relevant RBLC search results are provided in Appendix C.

Table 3-6. Summary of Available GHG Emission Reduction Measures

GHG Emission Reduction Measure	Description
Leakless Technology Components	Eliminates fugitive emissions by eliminating leaks.
Instrument Leak Detection (Method 21) and Repair	Instrumented leak detection and repair (LDAR) monitors components to identify leaks in need of repair.
LDAR Program with remote sensing technology	This technology involves remote sensing of leaks using sophisticated infrared cameras.
Audio, Visual, and Olfactory (AVO) detection of leaks followed by repair	Monitoring of leaks is done by physical inspections.
High quality components	A key element in control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed.

3.7.2. Eliminate Technically Infeasible Options (Step 2)

All of the control strategies listed above are technically feasible.

3.7.3. Rank Remaining Control Technologies (Step 3)

Leakless technologies are nearly 100% effective in eliminating fugitive emissions from the locations where installed. Instrumented LDAR is the next most effective control as it provides 97% control efficiency of both CO_2 and CH_4 (based on implementation of TCEQ's 28VHP monitoring program). LDAR with remote sensing is the third most effective control, providing 75% control of both CO_2 and CH_4. AVO is ranked fourth amongst the control options and results in 30% control of both CO_2 and CH_4. Use of high quality components does not have a measurable control efficiency and, while INVISTA plans to utilize, this option will not be evaluated further as BACT.

3.7.4. Evaluation of Most Stringent Controls (Step 4)

Leakless Technology Components

Because of their high cost, these specialty components are, in practice, selectively applied only as absolutely necessary for toxic or hazardous components. Thus this technology is generally considered cost prohibitive except for specialized service. GHG emissions from fugitives are minimal so implementing leakless technology would not be cost effective. Therefore, use of leakless technology components is considered economically infeasible for control of GHG emissions from fugitive components.

Instrumented LDAR

LDAR programs are typically used to control VOCs and can achieve up to 97% control of VOC emissions. The hydrogen/ammonia unit will have VOC emissions greater than 25 tpy. Based on TCEQ Tier I BACT for equipment leak fugitives at chemical sources, the appropriate control is implementation of TCEQ's 28VHP leak detection and repair program, as shown in Table 3-11. Although not specifically designed for GHG emissions, LDAR programs can be used to control GHGs since GHGs are generally present in the same components that would be included in an LDAR program for VOC. TCEQ's 28VHP LDAR program will be implemented for control of fugitive VOC emissions, and this LDAR program will result in co-control of fugitive GHG emissions. It is assumed that the same control factors for VOC emissions can be applied to GHG emissions. Instrumented LDAR is the second most effective control after leakless technology components. Since leakless technology has been ruled out, INVISTA will select TCEQ's 28VHP LDAR program as BACT for GHG fugitive components.

Table 3-7. TCEQ Chemical Sources Current BACT Requirements for Equipment Leak Fugitives

Year	Source Type	Pollutant	Minimum Acceptable Control	Control Efficiency or Details
2011	Equipment Leak Fugitives	Uncontrolled VOC emissions < 10 tpy	None	
		10 tpy < uncontrolled VOC emissions < 25 tpy	28M leak detection and repair program	75% credit for 28M
		Uncontrolled VOC emissions > 25 tpy	28VHP leak detection and repair program	97% credit for valves, 85% for pumps and compressors
		VOC vp < 0.002 psia	No inspection required	No fugitive emissions expected
		Approved odorous compounds: NH3, C12, H2S, etc.	Audio/Visual/Olfactory (AVO) inspection twice per shift	Appropriate credit for AVO program

LDAR with remote sensing

LDAR with remote sensing is a less effective control than instrumented LDAR, therefore instrumented LDAR is chosen as BACT over LDAR with remote sensing.

AVO

AVO is rejected as BACT since the higher ranked instrumented LDAR program will be adopted for control of fugitive GHG emissions.

3.7.5. Selection of GHG BACT (Step 5)

GHG BACT for the fugitives is to implement a leak detection and repair program equivalent to the TCEQ 28VHP LDAR program. Any leaking component will be repaired and recorded as required in the 28 VHP program. The gas detector shall conform to requirements listed in Method 21 of 40 C.F.R., Subpart 60, Appendix A. The gas analyzer shall be calibrated with CH_4 and have a response factor no less than 10 for the pollutant or combination of pollutants being measured. Replacements for leaking components will be remonitored when placed back in service.

4. AIR QUALITY ANALYSIS

4.1. DISPERSION MODELING AND AMBIENT MONITORING REQUIREMENTS

The application does not include dispersion modeling and ambient monitoring data for GHG, consistent with EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases," which states:

> "Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21 (k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause or contribute to a violation of the NAAQS are not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO_2 or GHGs."

In addition, EPA's guidance goes on to state:

> "Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs."

5. ANALYSIS OF CLASS I AREA IMPACTS

Emissions from the project of non-GHG, NSR-regulated pollutants will have no impact on the nearest Class I area, Big Bend National Park, which is located approximately 575 km from the site.

6. ADDITIONAL IMPACTS ANALYSIS

This application does not include an assessment of impacts from GHGs in the context of an additional impacts analysis or area analysis, consistent with EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases," which states:

> "Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs."

INVISTA has focused on addressing the reduction of GHG emissions in the BACT analysis section of this application.

For the reasons set forth above, INVISTA believes that a Section 52.21(o) analysis is not required for this permit application. For the same reasons, Section 52.21(k), (m), and (p) analyses are not required this permit application. Nevertheless, and without waiving or otherwise compromising this position, INVISTA provides the following Section 52.21(o) analysis.

1. ***Impairment to visibility, soils, and vegetation.*** "The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value." 40 C.F.R. § 52.21(o)(1).

   All construction and operation associated with the proposed project will be within the existing facility and will not impact soils or vegetation having any commercial or recreational value. The project is designed to replace the current importation of ammonia and provide steam to the balance of the existing facility. No general commercial, residential, industrial, or other growth will occur as a direct result of this project. The impacts will be below the respective Significant Impact Level for all criteria pollutants for which there is an increase in allowable emissions due to this project. As such, there is no impact to visibility, soils, or vegetation from this project.

2. ***Growth analysis.*** "The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification." 40 C.F.R. § 52.21(o)(2).

The project is designed to replace the import of ammonia and provide steam to the balance of the existing facility. Although construction and operation—and in particular, increases to the local tax base—of the facility will create important, generalized economic benefits in the region, the relatively small number of incremental jobs to be added by the project is not projected to result in significant incremental industrial, commercial, or residential source growth that the region does not already have the capacity to accommodate. Therefore, there will not be any resulting emissions nor air quality impacts from general commercial, residential, industrial or other growth due to this project.

3. ***Visibility monitoring.*** "The Administrator may require monitoring of visibility in any Federal class I area near the proposed new stationary source for major modification for such purposes and by such means as the Administrator deems necessary and appropriate." 40 C.F.R. § 52.21(o)(3).

   Visibility monitoring is not required for this project because emissions from the project of non-GHG, NSR-regulated pollutants relevant to a visibility analysis will have no impact on the nearest Class I area, Big Bend National Park, which is located approximately 575 km from the site.

7. OTHER EPA AIR REGULATIONS

The proposed hydrogen/ammonia complex is to be located in Victoria County, which is currently classified as an attainment or unclassified area for all criteria pollutants.[41] The INVISTA Victoria site is an existing major stationary source of criteria pollutant emissions as defined by 40 C.F.R. § 52.21(b)(1)(i)(a), based on its classification as a chemical process plant and its potential to emit one or more criteria pollutants in excess of 100 TPY. The proposed combined hydrogen/ammonia unit is considered a major source under the PSD program, since it has the potential to emit (PTE) the following criteria pollutants in quantities greater than the respective significant emission rate (SER): carbon monoxide (CO), nitrogen oxides (NO_x), Volatile Organic Compounds (VOCs), and particulate matter (PM) including $PM_{2.5}$ and PM_{10}. Therefore, the proposed project will trigger Federal PSD review for NO_x, CO, VOC, PM, $PM_{2.5}$, and PM_{10}. Accordingly, an application for a PSD and state new source review permit for non-GHG emissions addressing each of these requirements will be submitted to TCEQ.

Applicable NSPS and NESHAP requirements will be addressed in the TCEQ PSD Permit Application submittal.

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[41] The United States Protection Agency (U.S. EPA) Green Book. Source: http://www.epa.gov/oar/oaqps/greenbk\, accessed July 2013

8. NON-CLEAN AIR ACT REQUIREMENTS

8.1. ENDANGERED SPECIES ACT

Section 7(a)(2) of the Endangered Species Act (ESA), 16 U.S.C. § 1536(a)(2), and its implementing regulations at 50 C.F.R. Part 402, requires EPA to consult with the U.S. Fish and Wildlife Service or the National Marine Fisheries Service, or both under certain circumstances, to ensure that EPA's issuance of a GHG PSD permit is not likely to jeopardize the continued existence of any federally listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. INVISTA has prepared and delivered with this application a biological assessment to support EPA's obligations under ESA Section 7.

8.2. COASTAL ZONE MANAGEMENT ACT

The Coastal Zone Management Act (CZMA) was enacted on October 27, 1972, to encourage coastal states, Great Lake States, and United States territories and commonwealths (collectively referred to as "coastal states") to develop comprehensive programs to manage and balance competing uses of and impacts to coastal resources. The CZMA emphasizes the primacy of state decision-making regarding the coastal zone. Section 307 of the CZMA, 16 U.S.C. § 1456, called the federal consistency provision, is an incentive for states to join the national coastal management program and is a tool that states use to manage coastal uses and resources and to facilitate cooperation and coordination with federal agencies. Texas has incorporated the requirements of Section 307 and its implementing regulations. *See* Texas Administrative Code, tit. 31, § 506.30(a) ("Upon filing an application for a federal agency action listed under § 506.12 of this title (relating to Federal Actions Subject to the Coastal Management Program), the applicant shall provide to the council secretary a consistency certification..."). Texas has not included EPA's issuance of PSD preconstruction permits on its list of federal license or permit activities. *See id.* § 506.12(a)(2) (listing five non-PSD EPA licenses or permits subject to the consistency requirement). Accordingly, EPA's action in issuing a PSD GHG permit does not trigger the requirement for INVISTA to obtain a consistency certification under Texas' federally-approved coastal management program. In accordance with 15 C.F.R. § 930.54(a)(2), publication of the availability of this application in the Federal Register will constitute constructive notice to Texas of the proposed permit activity.

8.3. NATIONAL HISTORIC PRESERVATION ACT

Section 106 of the National Historic Preservation Act, 16 U.S.C. § 470, and its revised regulations, 36 C.F.R. Part 800, require EPA to take into account the effects of its actions (*e.g.*, any action authorized, funded, or carried out by EPA) on historic properties, and to provide the Advisory Council on Historic Preservation a reasonable opportunity to comment on those undertakings. Historic properties are defined in Federal law as those properties that are listed in, or meet the criteria for listing in, the National Register of Historic Places. This is typically carried out through consultation with the State Historic Preservation Officer, and in the case of projects involving tribal lands, with the tribal representative. INVISTA has prepared and delivered along with this permit application a cultural resources assessment that will review the potential effects of the project's construction, operations, and air emissions on historical properties or other culturally significant features or landscapes within a designated Area of Potential Effect.

8.4. MAGNUSON-STEVENS FISHERIES CONSERVATION AND MANAGEMENT ACT

Under Section 305(b) of the Magnuson-Stevens Fisheries Conservation and Management Act ("MSA"), federal agencies must consult with the Secretary (*i.e.*, the National Marine Fisheries Service, or "NMFS") "with respect to any action authorized, funded, or undertaken, or proposed to be authorized, funded, or undertaken, by such agency that may adversely affect any essential fish habitat identified under [the MSA]." 16 U.S.C. § 1855(b)(2). NMFS has identified essential fish habitat (EFH) to include the Victoria Barge Canal, which is adjacent to the INVISTA Victoria site.

The MSA regulations define "adverse effect" to mean:

> [A]ny impact that reduces quality and/or quantity of EFH. Adverse effects may include direct or indirect physical, chemical, or biological alterations of the waters or substrate and loss of, or injury to, benthic organisms, prey species and their habitat, and other ecosystem components, if such modifications reduce the quality and/or quantity of EFH. Adverse effects to EFH may result from actions occurring within EFH or outside of EFH and may include site-specific or habitat-wide impacts, including individual, cumulative, or synergistic consequences of actions.

50 C.F.R. § 600.810.

As part of the consultation process, Federal agencies should provide early notice to NMFS of federal actions with a reasonably foreseeable adverse effect on EFH, 50 C.F.R. 600.920(a)(3), and must provide NMFS with a written EFH Assessment. 50 C.F.R. § 600.920(e). According to INVISTA's initial evaluation, it is not reasonably foreseeable that the project will result in adverse effects on EFH, including, but not limited to, effects from vessel traffic or from wastewater or stormwater discharges to the Victoria Barge Canal. To the extent its initial evaluation changes, INVISTA will prepare an EFH Assessment consistent with the requirements of MSA. INVISTA does not at this point intend to initiate contact with NMFS.

APPENDIX A: EMISSION CALCULATIONS

INVISTA S.à r.l. Victoria Site
Hydrogen and Ammonia Manufacturing Project
Victoria, Texas

Source	CO2 ton/yr	CH4 ton/yr	N2O ton/yr	CO2e ton/yr
Reformer - Normal Operations	1,679,987	0.03	0.02	1,679,987
High-Btu Offgas	194,312	1.98E+00		194,314
Reformer Stack Total	1,874,299	2.01	0.02	1,874,301

Reformer - MSS	5,255	2.08E+00	3.07E+00	5,260
WPH Boilers - Demand Increase MSS only	799	3.17E-01	4.67E-01	800
NH3 Plant Startup Heater	3,608	1.43E+00	2.11E+00	3,612
Fugitives - PSA Offgas	8.23	47.21	---	55.4
Fugitives - High-Btu Offgas	0.17	3.20	---	3.37
Fugitives - Natural Gas	0.29	1065.70	---	1,066
H2 Plant Flare - Normal	2,225	8.81E-01	1.30E+00	2,227
H2 Plant Flare - MSS	14,820	---	---	14,820
NH3 Plant Flare - Normal	2224.92	8.81E-01	1.30E+00	2,227
NH3 Plant Flare - MSS	9.17	---	---	9.17

Total - CO2e Basis (tpy) 1,904,380

Source	Data	Units
Hydrogen Plant Total NG Usage	3118000	scfh
Reformer NG to Burners	743511	scfh
NG to Duct Burner	90363	scfh
Natural Gas Heat Value (HHV)	1035	Btu/scf
Hours of Operation	8760	hrs/yr

GHG Emissions

Pollutant	Factor	Annual Emissions tpy	GWP	CO2e Emissions tpy
CO2	0.05306 tonnes CO2/total mmBtu	1,679,987	1	1,679,987
N20	0.0001 kg/mmBtu Fuel	9.49E-05	310	2.94E-02
CH4	0.001 kg/mmBtu Fuel	9.49E-04	21	1.99E-02
			Total	1,679,987

Example Calculation

CO2 Emissions

$$\frac{3118000\ \text{scf}}{\text{hr}} * \frac{1035\ \text{Btu}}{\text{scf}} * \frac{1\ \text{mmBtu}}{1000000\ \text{Btu}} * \frac{0.05306\ \text{tonnes CO2}}{\text{mmBtu}} * \frac{8760\ \text{hrs}}{\text{yr}} * \frac{1.12\ \text{ton}}{\text{tonne}} * \underset{\text{(GWP)}}{1} = \frac{1679987\ \text{tons CO2e}}{\text{yr}}$$

Notes:

1. Reformer NG Feed is from Heat and Material Balance Case 1-A-NG, stream No. 99-001. Note - based upon total plant natural gas at BL consistent with 40 CFR 98 Subpart P calculation basis. This approach captures both feed and fuel carbon, as well as PSA tailgas and flares.
2. Reformer NG to burners is from Heat and Material Balance Case 1-A-NG, stream No. 03-008 and is used solely for calculated fuel based emissions.
3. Duct burner NG is from Heat and Material Balance Case 1-A-NG, stream No. 03-010.
3. CO2 emissions factor from EPA's technical support document for hydrogen plants, page 9, Table H5. Factor is based upon the total of feed and fuel.
4. Methane and Nitrous Oxide emissions factors from 40 CFR 98 Subpart C, Table C-2.

INVISTA S.à r.l. Victoria Site
Hydrogen and Ammonia Manufacturing Project
Victoria, Texas

Reformer Max firing rate [1]	1560.31	MMBtu/hr
MSS NG firing rate [2]	624.12	MMBtu/hr
NG flowrate	603017	scfh
Heating Value [3]	1035	Btu/scf
Operating time [4]	144	hrs/yr

Pollutant	Emission Factor kg/MMBtu	Annual Emissions tpy	GWP	CO2e emissions tpy
CO2 [5]	53.06	5255	1	5,255
N2O [6]	1.00E-04	9.90E-03	310	3.1
CH4 [6]	1.00E-03	9.90E-02	21	2.080
CO2e	-	-	-	**5,260**

[1] Data provided by INVISTA: reformer max firing rate is based upon H&MB Case 1-A-NG Total Firing Rate

[2] MSS natural gas firing rate is 40% of the maximum firing rate

[3] Natural gas heating value is a site-specific factor for INVISTA's Victoria Site.

[4] Operating time is based on expected number of events per year (6 events) and duration of each event (12 hours).

[5] CO2 emissions factor from EPA's technical support document for hydrogen plants, page 9, Table H5. Factor is based upon the total of feed and fuel.

[6] Methane and Nitrous Oxide emissions factors from 40 CFR 98 Subpart C, Table C-2.

Source	Data	Units
PSA Offgas Firing Rate	790.77	mmBtu/hr
PSA Offgas Fuel Flowrate	3240874	scfh
High BTU offgas Firing Rate	728.80	mmBtu/hr
High BTU offgas to Burners	2429344	scfh
High BTU offgas to Burners	52984	lb/hr
High BTU Offgas Heating Value	300	Btu/scf
PSA Offgas Heating Value	244	Btu/scf
Hours of Operation	8760	hrs/yr
SCR NOx Removal Efficiency	90%	

NOx Emissions

Fuel	Factor		Hourly Emissions	Annual Emissions
	lb/mmBtu	lb/mmscf	lb/hr	tpy
High BTU Offgas - Average	0.338	—	—	107.89
High BTU Offgas - Maximum Hourly	0.507	---	36.95	—
PSA Offgas Fuel Firing	—	33	10.85	47.54
		Total	47.80	155.43

CO2 Emissions - High BTU Offgas Only

Pollutant	Factor lbs/lb Fuel	Annual Emissions tpy	Global Warming Potential	CO2e Emissions tpy
CO2	0.8373	194,312	1	194,312
CH4	4.06E-07	9.42E-02	21	1.98E+00
			Total	194,314

Example Calculation

NOx - High BTU Offgas

$$\frac{2429344\ \text{scf}}{\text{hr}} * \frac{300\ \text{Btu}}{\text{scf}} * \frac{1\ \text{mmBtu}}{1000000\ \text{Btu}} * \frac{0.3\ \text{lb}}{\text{mmBtu}} * \frac{8760\ \text{hrs}}{\text{yr}} * \frac{1\ \text{ton}}{2000\ \text{lb}} * \frac{10\%}{\text{SCR Removal}} = \frac{107.89\ \text{tons}}{\text{yr}}$$

Notes:

1. Reformer High BTU offgas firing rate is calculated as the difference between the maximum total reformer firing rate and the PSA tailgas firing rate provided by Uhde
2. The reformer High BTU offgas flow to the burners is calculated using the firing rate and the heating value. The flowrate is converted to a mass flow using a density of 0.0219 lb/scf
3. NOx factor for High BTU offgas is from site specific source testing, consistent with WPH basis. Max hourly emissions are based upon an expected 50% increase as worst case
4. NOx factor for supplemental fuel firing is from EPA's AP-42 Table 1.4-1, ratioed for stream heat value
5. CO2 emissions factor from High BTU offgas firing is based upon site specific factor.
6. Methane emissions factor is based upon site specific data for the High BTU offgas.
7. CO2 emissions are based upon only the High BTU offgas firing as supplemental fuel firing is accounted for in the reformer CO2 emissions basis.

INVISTA S.à r.l. Victoria Site
Hydrogen and Ammonia Manufacturing Project
Victoria, Texas

Normal Operation [10]

NG flowrate [1]	4200	scfh
Heating Value [1]	1035	Btu/scf
Operating time [1]	8760	hrs/yr

Pollutant	Emission Factor kg/MMBtu	Annual Emissions tpy	GWP	CO2e emissions tpy
CO2 [2]	53.02	2225	1	2224.923
N2O [3]	1.00E-04	4.20E-03	310	1.301
CH4 [3]	1.00E-03	4.20E-02	21	0.881
CO2e	-	-	-	**2227**

MSS

Natural Gas Flowrate	110,827	lbmol/yr
Hydrogen flowrate	7,410,443	lbmol/yr
High Btu Offgas Flowrate	345	lbmol/yr
PSA Feed Gas Flowrate	1,536,770	lbmol/yr
PSA Offgas Flowrate	252,085	lbmol/yr
Synthesis Gas Flowrate	3,435,245	lbmol/yr

Constituents	Natural Gas		Hydrogen		High BTU Offgas		PSA Feed Gas		PSA Offgas		Synthesis Gas		Total flowrate	# of Carbon atoms	Carbon flowrate
	Composition [9] mol%	Flowrate lbmol/yr	Composition [9] mol%	Flowrate lbmol/yr	Composition [9] mol%	Flowrate lbmol/yr	Composition [9] mol%	Flowrate lbmol/yr	Composition [9] mol%	Flowrate lbmol/yr	Composition [9] mol%	Flowrate lbmol/yr	lbmol/yr		lbmol/yr
CH4	91.88%	101828	0.01%	741	1.06%	4	5.25%	80680	15.78%	39779	0.01%	344	223,376	1	223,376
C2H6	2.29%	2538											2,538	2	5,076
C3H8	0.42%	465											465	3	1,396
i-C4H10	0.10%	111											111	4	443
n-C4H10	0.09%	100											100	4	399
i-C5H12	0.07%	78											78	5	388
n-C6H14	0.08%	89											89	6	532
Compound with one carbon atom					0.13%	0.45							0.45	1	0.45
Compound with two carbon atoms					0.13%	0.45							0.45	2	0.90
CO			0.00065%	48	13.47%	46.43	0.48%	7376	1.44%	3630	0.0005%	17	11,118	1	11,118
CO2	0.97%	1075	0.00065%	48	1.19%	4.10	18.72%	287683	56.36%	142075			430,886	1	430,886
H2			99.90%	7403033			74.96%	1151963	24.83%	62593	74.95%	2574716	11,192,305		
N2	1.22%	1352	0.09%	6669			0.30%	4610	0.71%	1790	25.03%	859842	874,263		
Ar											0%	344	344		
O2											0.0003%	10	10		
H2O			0%				0.29%	4457	0.88%	2218			6,675		

Total C Flowrate (lbmol/yr)	**673,615**
Total CO2 Flowrate (tpy)	**14,820**

[1] Data provided by INVISTA: NG flowrate is from Uhde gaseous emissions table rev. 3 line 3, assumes NG flow to flares is split equally between the H2 flare and the NH3 flare. Natural gas heating value is a site-specific factor for INVISTA's Victoria Site, Operating time assumes continuous operation

[2] CO2 emissions factor is from Table C-1 of 40 CFR 98, Subpart C for combustion sources.

[3] N2O and CH4 emissions factors are from Table C-2 of 40 CFR 98, Subpart C for combustion sources.

[4] Data provided by INVISTA, from Udhe gaseous emissions table. Includes Desulfurization Vessel Flaring, Desulfurization Vessel Depressurization, and Desulfurization Vessel Clearing

[5] Data provided by INVISTA, from Udhe gaseous emissions table. Includes Syngas Flaring and PSA Vessel Clearing.

[6] Data provided by INVISTA, from Udhe gaseous emissions table. Includes PSA feed flaring.

[7] Data provided by INVISTA, from Udhe gaseous emissions table. Includes PSA offgas flaring.

[8] Data provided by INVISTA, from Udhe gaseous emissions table. Includes H2 Product Flaring, H2 Product Demand Changes, and H2 Plant Clearing.

[9] Data provided by INVISTA, from Udhe gaseous emissions table.

[10] Normal operation consists of natural gas pilots plus dry gas seals flaring. However, the dry gas seals composition is mostly H2 and N2, with negligible amounts of carbon in the stream. Therefore, for purposes of GHG emission calculations, normal operation GHG emissions from the flare are just based on natural gas pilot flaring.

INVISTA S.à r.l. Victoria Site
Hydrogen and Ammonia Manufacturing Project
Victoria, Texas

Normal Operation [6]

NG flowrate [1]	4200	scfh
Heating Value [1]	1035	Btu/scf
Operating time [1]	8760	hrs/yr

Pollutant	Emission Factor kg/MMBtu	Annual Emissions tpy	GWP	CO_2e emissions tpy
CO_2 [2]	53.02	2225	1	2224.92
N_2O [3]	1.00E-04	4.20E-03	310	1.30
CH_4 [3]	1.00E-03	4.20E-02	21	0.88
CO_2e	-	-	-	**2227**

MSS

Synloop	62,112	lbmol/yr
NH_3 Fuelgas	4,553	lbmol/yr
NH_3 Flashgas	5,682	lbmol/yr
Compressor Casing Clearing	14,666	lbmol/yr
07F004 Line Purge	5,981	lbmol/yr

Constituents	Synloop		NH_3 Fuelgas		NH_3 Flashgas		Compressor Casing Clearing		07F004 Line Purge		Total flowrate	Molecular Weight	# of Carbon atoms	Carbon flowrate
	Composition [5] mol%	Flowrate lbmol/yr	Composition [5] mol%	Flowrate lbmol/yr	Composition [5] mol%	Flowrate lbmol/yr		Flowrate lbmol/yr		Flowrate lbmol/yr	lbmol/yr	(lb/lb-mol)		lbmol/yr
CH_4	0.40%	248	1.86%	85	1.03%	59	0.01%	1	0.40%	24	417	16.04	1	417
H_2	69.68%	43279	65.27%	2971	48.67%	2766	74.95%	10992	69.68%	4168	64,176	2.02		
N_2	24.91%	15472	31.80%	1448	22.91%	1302	25.03%	3671	24.91%	1490	23,382	28.01		
Ar	0.45%	280	1.05%	48	0.70%	40	0.01%	1	0.45%	27	395	39.948		
NH_3	4.56%	2832	0.0200%	1	26.69%	1517			4.56%	273	4,623	17.031		
H_2O											0	18.02		
											Total C flowrate (lbmol/yr)			**417**
											Total CO_2 flowrate (tpy)			**9.17**

[1] Data provided by INVISTA: NG flowrate is from Uhde gaseous emissions table rev. 3 line 3, assumes NG flow to flares is split equally between the H_2 flare and the NH_3 flare. Natural gas heating value is a site-specific factor for INVISTA's Victoria Site, Operating time assumes continuous operation

[2] CO_2 emissions factor is from Table C-1 of 40 CFR 98, Subpart C for combustion sources.

[3] N_2O and CH_4 emissions factors are from Table C-2 of 40 CFR 98, Subpart C for combustion sources.

[4] Data provided by INVISTA, from Udhe gaseous emissions table.

[5] Data provided by INVISTA, from Udhe gaseous emissions table.

[6] Normal operation consists of natural gas pilots plus dry gas seals flaring. However, the dry gas seals composition is mostly H_2 and N_2, with negligible amounts of carbon in the stream. Therefore, for purposes of GHG emission calculations, normal operation GHG emissions from the flare are just based on natural gas pilot flaring.

Source	Data	Units
Heater Max Firing Rate	49.57	mmBtu/hr
Natural Gas Heat Value (HHV)	1035	Btu/scf
Hours of Operation	1248	hrs/yr

Criteria Emissions

Pollutant	Factor lb/mmscf	Hourly Emissions lb/hr	Annual Emissions tpy
PM, PM10 & PM2.5	7.6	0.36	0.23
NOx	50	2.39	1.49
CO	84	4.02	2.51
SO2	0.6	0.03	0.018
VOC	5.5	0.26	0.16

CO2 Emissions

Pollutant	Factor kg/mmBtu	Annual Emissions tpy	Global Warming Potential	CO2e Emissions tpy
CO2	53.02	3,608	1	3,608
N20	1.00E-04	6.80E-03	310	2.11E+00
CH4	1.00E-03	6.80E-02	21	1.43E+00
			Total	3,612

Example Calculation

NOx

$$\frac{\underline{49.57\ \text{mmBtu}}}{\text{hr}} * \frac{\underline{1000000\ \text{Btu}}}{\text{mmBtu}} * \frac{\underline{1\ \text{scf}}}{1035\ \text{Btu}} * \frac{\underline{1\ \text{mmscf}}}{1000000\ \text{scf}} * \frac{\underline{50.0\ \text{lb}}}{\text{mmscf}} * \frac{\underline{1248\ \text{hrs}}}{\text{yr}} * \frac{\underline{1\ \text{ton}}}{2000\ \text{lb}} = \frac{\underline{1.49\ \text{tons}}}{\text{yr}}$$

Notes:

1. Heating maximum firing rate and hours of operation provided by Uhde.
2. PM factor is from EPA's AP-42 Table 1.4-2, PM (Total) value. This conservatively assumes that all PM is PM10 and PM2.5.
3. NOx factor is from EPA's AP-42 Table 1.4-1 for small boilers (< 100 mmBut/hr) with low NOx burners.
4. CO factor is from EPA's AP-42 Table 1.4-1.
5. SO2 factor is from EPA's AP-42 Table 1.4-2. Assumes pipeline grade natural gas sulfur loading of 2000 grains/mmscf.
6. VOC factor is from EPA's AP-42 Table 1.4-2.
7. CO2 emissions factor is from Table C-1 of 40 CFR 98, Subpart C for combustion sources.
8. N2O and CH4 emissions factors are from Table C-2 of 40 CFR 98, Subpart C for combustion sources.

Hours of Operation 8760 hrs/yr

Fugitive Emission Calculations:
Hydrogen Plant PSA Offgas

Emission Source	Component Count[1]	Uncontrolled Emissions Factor[2] (lb/hr-source)	Control Factor[3]	Hourly Emissions (lb/hr)
Valves - Gas	500	0.0089	97%	0.13
Valves - Gas (DM)		0.0089	75%	0.00
Valves - Light Liquid		0.0035	97%	0.00
Valves - Light Liquid (DM)		0.0035	75%	0.00
Valves - Heavy Liquid		0.0007	0%	0.00
Pumps - Light Liquid		0.0386	85%	0.00
Pumps - Heavy Liquid		0.0161	0%	0.00
Flanges - Gas	1480	0.0029	30%	3.00
Flanges - Light Liquid		0.0005	30%	0.00
Flanges - Heavy Liquid		0.00007	30%	0.00
Compressors	2	0.5027	85%	0.15
Pressure Relief Valves	20	0.2293	100%	0.00
Sampling Connections	10	0.033	97%	0.01

Total Hourly Emissions 3.30

Component Speciation:	Mole %
CH4	15.56%
H2	25.29%
N2	0.69%
CO	1.48%
CO2	56.98%

Emissions Speciation

Contaminant	Hourly Emission Rate (lb/hr)	Annual Emission Rate (tons/yr)	GWP	Annual CO2e Emissions Rate (tons/yr)
Methane	0.51	2.25	21	47.21
CO	0.05	0.21	---	---
CO2	1.88	8.23	1	8.23
			Total	55.44

Notes:
1. Component counts are based upon a similar sized hydrogen production facility provided by Trinity or preliminary P&IDs by Uhde, whichever is greater.
2. The emissions factors used are SOCMI without ethylene factors from the TCEQ Fugitive Guidance Document dated October 2000.
3. The control factors are based upon the 28VHP program from the TCEQ Fugitive Guidance Document dated October 2000. Difficult to monitor (DM) sources are monitored at least annually.
4. Relief valves are either routed to a flare for control or are equipped with a rupture disk upstream of the relief device as required by TCEQ BACT requirements.
5. Component composition is based upon the PSA tailgas composition from the Heat and Materia Balance, page 7, stream No. 06-102.

Hours of Operation 8760 hrs/yr

Fugitive Emission Calculations:
High BTU Offgas

Emission Source	Component Count[1]	Uncontrolled Emissions Factor[2] (lb/hr-source)	Control Factor[3]	Hourly Emissions (lb/hr)
Valves - Gas	560	0.0089	97%	0.15
Valves - Gas (DM)		0.0089	75%	0.00
Valves - Light Liquid	100	0.0035	97%	0.01
Valves - Light Liquid (DM)		0.0035	75%	0.00
Valves - Heavy Liquid		0.0007	0%	0.00
Pumps - Light Liquid	2	0.0386	85%	0.01
Pumps - Heavy Liquid		0.0161	0%	0.00
Flanges - Gas	1480	0.0029	30%	3.00
Flanges - Light Liquid	240	0.0005	30%	0.08
Flanges - Heavy Liquid		0.00007	30%	0.00
Compressors		0.5027	85%	0.00
Pressure Relief Valves	10	0.2293	100%	0.00
Sampling Connections	20	0.033	97%	0.02

Total Hourly Emissions 3.28

Component Speciation:	Mole %
CH4	1.06%
CO	13.47%
CO2	1.19%

Emissions Speciation

Contaminant	Hourly Emission Rate (lb/hr)	Annual Emission Rate (tons/yr)	GWP	Annual CO2e Emissions Rate (tons/yr)
CH4	0.03	0.15	21	3.20
CO	0.44	1.94	---	---
CO2	0.04	0.17	1	0.17
			Total	3.37

Notes:

1. Component counts are based upon a similar sized hydrogen production facility provided by Trinity or preliminary P&IDs by Uhde, whichever is greater.
2. The emissions factors used are SOCMI without ethylene factors from the TCEQ Fugitive Guidance Document dated October 2000.
3. The control factors are based upon the 28VHP program from the TCEQ Fugitive Guidance Document dated October 2000. Difficult to monitor (DM) sources are monitored at least annually.
4. Relief valves are either routed to a flare for control or are equipped with a rupture disk upstream of the relief device as required by TCEQ BACT requirements.
5. Component composition is based upon the offgas composition from the Heat and Material Balance, page 1, stream No. 99-021.

Hours of Operation 8760 hrs/yr

Fugitive Emission Calculations:
Natural Gas

Emission Source	Component Count[1]	Uncontrolled Emissions Factor[2] (lb/hr-source)	Control Factor[3]	Hourly Emissions (lb/hr)
Valves - Gas	1950	0.0089	97%	0.52
Valves - Gas (DM)		0.0089	75%	0.00
Valves - Light Liquid	80	0.0035	97%	0.01
Valves - Light Liquid (DM)		0.0035	75%	0.00
Valves - Heavy Liquid		0.0007	0%	0.00
Pumps - Light Liquid		0.0386	85%	0.00
Pumps - Heavy Liquid		0.0161	0%	0.00
Flanges - Gas	5650	0.0029	30%	11.47
Flanges - Light Liquid	130	0.0005	30%	0.05
Flanges - Heavy Liquid		0.00007	30%	0.00
Compressors		0.5027	85%	0.00
Pressure Relief Valves	30	0.2293	100%	0.00
Sampling Connections	10	0.033	97%	0.01

Total Hourly Emissions 12.05

Component Speciation:	Mole %
CH4	96.12%
C2H6	2.40%
C3H8	0.35%
i-C4H10	0.10%
n-C4H10	0.08%
i-C5H12	0.06%
n-C6H14	0.09%
N2	0.25%
CO2	0.55%

Emissions Speciation

Contaminant	Hourly Emission Rate (lb/hr)	Annual Emission Rate (tons/yr)	GWP	Annual CO2e Emissions Rate (tons/yr)
Methane	11.59	50.75	21	1065.70
CO2	0.07	0.29	1	0.29
			Total	1065.99

Notes:

1. Component counts are based upon a similar sized hydrogen production facility provided by Trinity or preliminary P&IDs by Uhde, whichever is greater.
2. The emissions factors used are SOCMI without ethylene factors from the TCEQ Fugitive Guidance Document dated October 2000.
3. The control factors are based upon the 28VHP program from the TCEQ Fugitive Guidance Document dated October 2000. Difficult to monitor (DM) sources are monitored at least annually.
4. Relief valves are either routed to a flare for control or are equipped with a rupture disk upstream of the relief device as required by TCEQ BACT requirements.
5. Component composition is based upon the PSA tailgas composition from the Heat and Material Balance, page 1, stream No. 99-001.

APPENDIX B: CCS COST EFFECTIVENESS

Appendix B

INVISTA Victoria Combined Hydrogen/Ammonia Unit

Carbon Capture and Sequestration Capital Costs Summary

Line No.	Description	Units	Denbury Case	Denver City Case
1	CO2 Captured	Tons/Yr	1,686,871	1,686,871
2	Pipeline	Miles	120	350
3	CO2 Capital	$MM	$500	$500
4	Pipeline Capital	$MM	$240	$770
5	Total CO2 Capital	$MM	$740	$1,270

Notes:

1. The CO2 capital costs have been estimated consistent with the approach found in the U.S. Department of Energy National Energy Technology Laboratory document "Assessment of Hydrogen Production with CO2 Capture Volume 1: Baseline State-of-the-Art Plants."
2. Pipeline capital costs have been estimated consistent with the approach found in the U.S. Department of Energy National Energy Technology Laboratory document "Estimating Carbon Dioxide Transport and Storage Costs" document.

APPENDIX C: RBLC SEARCH RESULTS

RBLC Search Results for Reformer GHG

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY COUNTY	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME CONDITION	CASE-BY-CASE BASIS	STANDARAD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION
LA-0263	ALLIANCE REFINERY	PHILLIPS 66 COMPANY	PLAQUEMINES	LA	07/25/2012 ACT	STEAM METHANE REFORMER (2291-SMR, EQT 0196)	REFINERY FUEL GAS	216	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	SELECTION OF MOST EFFICIENT H2 PURIFICATION PROCESS - PRESSURE SWING ADSORPTION, HEAT RECOVERY AIR PREHEATER (UNLESS HEAT FROM SMR STACK IS RECOVERED ELSEWHERE), ADIABATIC PRE-REFORMER, MAINTENANCE AND FOULING CONTROL, COMBUSTION AIR AND FEED/STEAM PREHEAT, COMBUSTION AIR CONTROLS (LIMITING EXCESS AIR), PROCESS INTEGRATION, FURNACE CONTROLS (GOOD COMBUSTION PRACTICES), NEW BURNER DESIGNS	183784	T/YR	12-MONTH ROLLING AVERAGE	BACT-PSD	0.05	LB/SCF H2 PRODUCTION	12-MONTH ROLLING AVERAGE

RBLC Search Results for Fugitives GHG

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY COUNTY	FACILITY STATE	PERMIT NUM	PERMIT ISSUANCE DATE	FACILITY DESCRIPTION	PROCESS NAME	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME CONDITION	CASE-BY-CASE BASIS	OTHER APPLICABLE REQUIREMENTS
LA-0263	ALLIANCE REFINERY	PHILLIPS 66 COMPANY	PLAQUEMINES	LA	PSD-LA-760	07/25/2012 ACT	PETROLEUM REFINERY. THE PROJECT ENTAILS CONSTRUCTION OF A NEW 20 MM SCF/DAY STEAM METHANE REFORMER TO MAKE HYDROGEN NEEDED TO PRODUCE ULTRA LOW SULFUR DIESEL.	HYDROGEN PLANT FUGITIVES (2291-FF, FUG 0026)	Carbon Dioxide Equivalent (CO2e)	IMPLEMENTATION OF THE LOUISIANA REFINERY MACT LEAK DETECTION AND REPAIR PROGRAM; MONITORING FOR TOTAL HYDROCARBON CONTENT INSTEAD OF VOC	0			BACT-PSD	
LA-0257	SABINE PASS LNG TERMINAL	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	CAMERON	LA	PSD-LA-703(M3)	12/06/2011 ACT	A liquefaction section of the terminal which will include 24 compressor turbines, two generator turbines, two generator engines, flares, acid gas vents, and fugitives	Fugitive Emissions	Carbon Dioxide Equivalent (CO2e)	conduct a leak detection and repair (LDAR) program	89629	TONS/YR	ANNUAL MAXIMUM	BACT-PSD	
OH-0281	RUMPKE SANITARY LANDFILL, INC	RUMPKE SANITARY LANDFILL, INC	HAMILTON	OH	14-05824, 14-05292	06/10/2004 ACT	HAMILTON COUNTY LANDFILL WITH LANDFILL GAS PRODUCTION	FUGITIVE EMISSIONS FROM LANDFILL AND GAS COLLECTION SYSTEM	Methane		45029	T/YR		BACT-PSD	NSPS , SIP

RBLC Search Results for Flares GHG

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY COUNTY	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME CONDITION	CASE-BY-CASE BASIS	OTHER APPLICABLE REQUIREMENTS	EMISSION LIMIT 2	EMISSION LIMIT 2 UNIT	EMISSION LIMIT 2 AVGERAGE TIME CONDITION
AK-0076	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	NORTH SLOPE	AK	08/20/2012 ACT	Combustion (Flares)	Fuel Gas	35	MMscf/yr	Carbon Dioxide	Good Combustion Practices	0			BACT-PSD		0		
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	HOOSIER ENERGY REC INC. MEROM GENERATING STATION	SULLIVAN	IN	11/10/2011 ACT	COAL BED METHANE-FIRED STANDBY FLARE W/PROPANE FIRED PILOT	COAL BED METHANE	25	MMBTU/H	Carbon Dioxide	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	3235	LB/MW-H		OTHER CASE-BY-CASE	N/A	4852	T/12 CONSEC MONTHS	12 MONTH CONSECUTIVE PERIOD
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	HOOSIER ENERGY REC INC. MEROM GENERATING STATION	SULLIVAN	IN	11/10/2011 ACT	COAL BED METHANE-FIRED STANDBY FLARE W/PROPANE FIRED PILOT	COAL BED METHANE	25	MMBTU/H	Methane	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	0.06	LB/MW-H		OTHER CASE-BY-CASE	N/A	0.08	T/12 CONSEC MONTHS	12 MONTH CONSECUTIVE PERIOD
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	HOOSIER ENERGY REC INC. MEROM GENERATING STATION	SULLIVAN	IN	11/10/2011 ACT	COAL BED METHANE-FIRED STANDBY FLARE W/PROPANE FIRED PILOT	COAL BED METHANE	25	MMBTU/H	Nitrous Oxide (N2O)	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	0.05	LB/MW-H		OTHER CASE-BY-CASE	N/A	0.08	T/YR	12 CONSECUTIVE MONTH PERIOD
LA-0257	SABINE PASS LNG TERMINAL	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	CAMERON	LA	12/06/2011 ACT	Marine Flare	natural gas	1590	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	2909	TONS/YR	ANNUAL MAXIMUM	BACT-PSD		0		
LA-0257	SABINE PASS LNG TERMINAL	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	CAMERON	LA	12/06/2011 ACT	Wet/Dry Gas Flares (4)	natural gas	0.26	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	133	TONS/YR	ANNUAL MAXIMUM	BACT-PSD		0		
OH-0330	RUMPKE SANITARY LANDFILL	RUMPKE SANITARY LANDFILL	BROWN	OH	12/23/2008 ACT	CANDLESTICK FLARE (5)	LANDFILL GAS			Methane	FLARE IS CONTROL	25	LB/H		N/A	NSPS , SIP	109.45	T/YR	
OH-0330	RUMPKE SANITARY LANDFILL	RUMPKE SANITARY LANDFILL	BROWN	OH	12/23/2008 ACT	OPEN FLARE	LANDFILL GAS			Methane	FLARE IS CONTROL	25	LB/H		N/A	NSPS , SIP	109.45	T/YR	