INVISTA™

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VIA FEDEX

March 12, 2012

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Mr. Jeff Robinson
Chief, Air Permits Section (6PD-R)
U. S. EPA Region 6
Fountain Place 12th Floor, Suite 1200
1445 Ross Avenue
Dallas, TX 75202-2733

Dear Mr. Robinson:

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

On behalf of INVISTA S.à r.l., I am submitting the enclosed application for a Greenhouse Gas PSD permit for the INVISTA Victoria West Powerhouse (WPH). As discussed during our meeting of January 13, 2012, installation of pollution controls to reduce NO_x emissions from the WPH boilers is required by a Consent Decree among INVISTA, the U.S. Environmental Protection Agency (U.S. EPA), the U.S. Department of Justice, and various state plaintiffs entered on July 28, 2009, which resolves alleged failure to procure PSD permits for projects implemented by the prior owner, from whom INVISTA purchased the Victoria facility in 2004. INVISTA also entered into a parallel compliance agreement with the Texas Commission on Environmental Quality. Pursuant to the Consent Decree and Texas Compliance Agreement, NO_x controls must be installed on the first of the WPH boilers by December 31, 2013. Therefore, permit authorization to begin construction is requested by no later than May 1, 2013.

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, "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers," October 2010, the RACT/BACT/LAER Clearinghouse, and other materials.

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

1) Installation of technologies to reduce NO_x emissions from the WPH boilers,
2) Modifications to the existing WPH boilers, including retubing, operational flexibility and efficiency improvements, and modernization, as necessary, and
3) Associated modifications to fuel system piping.

If you have any questions regarding this submittal, please call Pete Buckman at 361.580.5954 or e-mail peter.g.buckman@invista.com.

Sincerely,

Stephen W. Harvill

Stephen W. Harvill
Plant Manager

SWH/pgb
Enclosure

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

WAID ENVIRONMENTAL

United States Environmental Protection Agency
Greenhouse Gas Permit Application

INVISTA S.à r.l.
Victoria Site / West Powerhouse

Victoria, Victoria County, Texas

March 2012

Approved by:

Chris L. Bauer, P.E.

Chris L. Bauer, P.E.
Principal Engineer

STATE OF TEXAS
CHRISTOPHER LEE BAUER
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3-12-2012

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1.0 Introduction

INVISTA S.à r.l.'s (INVISTA's) Victoria Plant is a nylon intermediates plant which includes an operating unit known as the West Powerhouse (WPH). The West Powerhouse (WPH) includes four boilers (Numbers 1, 2, 3, and 4) which provide destruction of various liquid and gaseous process wastes in accordance with various applicable laws and regulations. In addition to destroying the process wastes, the boilers recover the energy generated by the combustion of the process wastes (also referred to as 'fuels' here) and supplemental natural gas, as needed, and use that energy to generate steam required by the process units at the Victoria Plant. The process is, therefore, inherently efficient. All four boilers are tangentially fired, Combustion Engineering Model VU-60 water-tube boilers. The WPH boilers currently operate under TCEQ Air Permit Number 812. The proposed project is addressed in more detail in Section 1.3 of this application.

Both the WPH and this particular project are unique. As set forth in detail in the technical sections of this application below, the WPH boilers are unique in that they burn combinations of low-BTU gaseous fuels, high-BTU gaseous fuels, liquid wastes and supplemental natural gas, which vary significantly on a short term basis. The boilers maximize energy recovery by generating steam from process derived waste streams. Due to their high destruction efficiency, the WPH boilers are used as primary and backup control devices for the destruction of liquid and gaseous fuels from the processes at the site. Accordingly, while INVISTA proposes as BACT to install most of the design and operational energy efficiency measures set forth as BACT for boilers in EPA guidance, INVISTA also proposes a CO_2e tons per year emission limitation. The project is unique in that its primary purpose is installation of pollution controls to reduce NO_x emissions on a very tight schedule pursuant to a Consent Decree with EPA resolving alleged failures to procure PSD permits for projects implemented by the prior owner from whom INVISTA purchased the facility in 2004. To meet the Consent Decree deadlines, INVISTA must begin actual construction of the project on or about May 1, 2013.

1.1 Facility Location

The INVISTA Victoria Plant is located at 2695 Old Bloomington Highway North, south of the city of Victoria in Victoria County, Texas. The plant is situated in a rural area approximately 10 miles south of the city of Victoria at Latitude 28°40'41" North, Longitude 96°57'17" West.

1.2 Area Map

The INVISTA Victoria plant is located in an area of primarily agricultural use, although residential and industrial properties are scattered throughout the area. The primary land use of properties immediately adjacent to the plant is listed below. An area map is included in Appendix A.

East: Agricultural/Undeveloped
South: Agricultural/Undeveloped
West: Agricultural/Undeveloped
North: Agricultural/Undeveloped

1.3 Requested Authorizations and Project Description

INVISTA is submitting this Greenhouse Gas (GHG) permit application to EPA Region 6 to obtain a prevention of significant deterioration (PSD) permit and is also submitting a separate application to the Texas Commission on Environmental Quality (TCEQ) to amend the existing TCEQ permit for the WPH. These applications seek to authorize the following:

1) Installation of technologies to reduce NO_x emissions from the WPH boilers,
2) Modifications to the existing WPH boilers, including retubing, operational flexibility and efficiency improvements, and boiler modernization, as necessary, and
3) Associated modifications to fuel system piping.

Installation of NO_x controls for the WPH boilers is required by a Consent Decree among INVISTA, the U.S. Environmental Protection Agency (U.S. EPA), the U.S. Department of Justice, and various state plaintiffs (not including Texas), entered on July 28, 2009 (the "Consent Decree"). The requirements of the Consent Decree, and thus the installation of NO_x control technologies for the WPH boilers are incorporated into a Compliance Agreement between INVISTA and the Texas Commission on Environmental Quality (TCEQ) entered on March 31, 2010 (the "Texas Compliance Agreement").

GHG emission rates from the WPH following this project are shown in Table 1(a) in Appendix B.

The NO_x controls installation and boiler modifications are planned to be conducted over a period of approximately four years beginning in 2013. The installation of NO_x controls on the first boiler is required to be completed by December 31, 2013. The installation of NO_x controls on the remaining three boilers must be complete on or before December 31, 2016.

Other Emission Sources

The project may include the addition of new fugitive emission components and the replacement of some existing fugitive emission components associated with the WPH fuel systems. Although the fuel system piping is not part of the boilers, the emissions of GHG compounds from these fugitive emission components are also addressed in this permit application because they may be included as part of the project.

2.0 Process Description

The INVISTA Victoria Plant consists of several process units that produce nylon intermediates. These process units generate various liquid and gaseous fuel streams that are combusted in the WPH boilers. The WPH boilers provide destruction of six liquid and eight gaseous fuels from the processes and produce steam for use in the process units.

There are four boilers in the WPH. Boilers 1 and 2 share a common stack (Emission Point Number (EPN) 15STK-005) and Boilers 3 and 4 share a common stack (EPN 15STK-006). The nominal steam production capacity of Boilers 1 and 2 is 300,000 lbs/hr each and the nominal steam production capacity of Boilers 3 and 4 is 400,000 lbs/hr each. A diagram of the WPH fuel streams is provided in Appendix C.

There are four primary fuel types combusted in the WPH boilers:

- Low-BTU gaseous fuels,
- High-BTU gaseous fuels,
- Liquid waste fuels, and
- Natural gas (which includes molecular sieve regeneration streams that are composed primarily of natural gas).

The quantities and compositions of the fuels can vary significantly on a short-term basis and the combustion of some fuels is intermittent in nature. The combination of fuels combusted in the boilers can also vary significantly.

The low-BTU (i.e., <100 BTU/scf) gaseous fuels provide little heat input to the boilers and are combusted in the boilers primarily to ensure destruction of potential air contaminant compounds in these streams to meet regulatory requirements. The quantities and compositions of low-BTU gaseous fuels combusted in the WPH boilers can vary significantly based on plant operations. Also, the low-BTU gaseous fuels can significantly impact GHG emission rates from the boilers on a short-term basis due to intermittent streams that contain N_2O.

High-BTU gaseous fuels are process gases sent to the boilers to recover the fuel value of these streams, as well as to ensure destruction of potential air contaminants in these streams. The quantities and compositions of the high-BTU gaseous fuels combusted in the WPH boilers can vary significantly based on plant operations. Although the high-BTU gaseous fuels generally produce less GHG emissions than the low-BTU gaseous fuels per unit of heat input to the boilers, the GHG emissions resulting from combustion of the high-BTU gaseous fuels can vary significantly due to the variation in the combinations and compositions of these fuels.

Liquid waste fuels are sent to the boilers to recover the fuel value of these streams and to ensure destruction of these waste streams in accordance with regulatory requirements. The quantities and compositions of liquid waste fuels combusted in the WPH boilers, and hence the GHG emissions resulting from the combustion of these fuels, can vary significantly based on plant operations.

In addition to the gaseous and liquid fuels from the process units, the boilers combust natural gas as supplemental fuel, as needed, to generate sufficient steam to meet site steam demand. The quantity of natural gas combusted in the WPH boilers can vary significantly due to changes in plant steam demand and the availability and composition of the gaseous and liquid fuels from the process units.

Because they combust waste liquids, the WPH boilers are subject to permit requirements for Boilers and Industrial Furnaces (BIFs) burning hazardous waste under the Resource Conservation and Recovery Act (RCRA) and the Hazardous Waste Combustor rules in 40 CFR Part 63, Subpart EEE. These requirements have a significant effect on the manner in which the WPH boilers must be operated, including operating in a manner that ensures destruction of the waste fuels in accordance with the RCRA permit for BIF units and the Subpart EEE requirements.

Recovering the heating value of the liquid and gaseous fuels from the process units is inherently energy efficient. While ensuring compliance with the permit requirements for BIF units, and 40 CFR Part 63, Subpart EEE, the WPH boilers provide energy recovery to produce steam for use in the site's process units. Combustion of the liquid and gaseous fuels from the process units in the boilers for energy recovery avoids generation of GHG and other criteria pollutant emissions that would otherwise result from incineration and/or flaring of the fuels from the process units and the combustion of greater quantities of supplemental natural gas or other traditional fuels in the WPH boilers to provide sufficient steam to the plant operations.

As part of routine operation, the boilers may be fired with 100% natural gas as well as various combinations of natural gas and gaseous and liquid fuels from the process units.

During startup or shutdown, the boilers are fired with 100% natural gas at rates no greater than the maximum rates during time periods other than startup or shutdown. Therefore, GHG emissions during boiler startup and shutdown will not be greater than the maximum rates that may occur during other operations.

3.0 Prevention of Significant Deterioration (PSD) Review

INVISTA is submitting an application to amend the existing WPH permit to authorize the following:

1. The installation of Selective Non-Catalytic Reduction (SNCR) to increase control of NO_x emissions from the WPH boilers to meet Consent Decree and Texas Compliance Agreement requirements;
2. Modifications to the existing WPH boilers, including installation of low-NO_x burners, retubing, operational flexibility and efficiency improvements, and boiler modernization, as necessary; and
3. Associated modifications to fuel system piping.

The INVISTA Victoria site is an existing major source of criteria pollutant emissions under PSD. The proposed project/changes to the WPH will not result in any criteria pollutant (NO_x, CO, $PM/PM_{10}/PM_{2.5}$, VOC and SO_2) emission rate increases that are greater than the PSD significance levels. A minor new source review permit amendment application is being submitted to the TCEQ for this project.

The INVISTA Victoria site is a major source of GHG emissions as defined by 40 CFR 52.21(b)(1)(i). As defined under the U.S. EPA GHG Tailoring Rule, the proposed changes to the WPH boilers will constitute a major modification for GHG emissions. Therefore, 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. Furthermore, 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.

3.1 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 and is not considering contemporaneous decreases because INVISTA does not expect to be able to demonstrate that the project is not subject to PSD by a Step 2 contemporaneous netting analysis.

Table 3.1
GHG PSD Applicability Determination

	GHG CO_2e Basis (TPY)	GHG Mass Basis (TPY)
Total Project Emissions Increase*	696,144	628,258
PSD Major Modification Threshold	75,000	0
Is PSD Permitting Required?	Yes	Yes

*Detailed calculations are provided in Section 6.

3.2 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."

3.3 Additional Impacts Analysis

The permit application addresses proposed changes to existing facilities, including the addition of boiler emission control systems to reduce NO_x emissions, as previously described. This application does not include a new "grass roots" facility. In addition, the proposed changes do not result in any criteria pollutant emission rate increases that are greater than the PSD significance levels. Therefore, the proposed changes are not expected to result in any significant additional impacts. The closest Class I area is Big Bend National Park located approximately 224 miles (360 km) from the site.

This application does not include an assessment of impacts from GHGs in the context of an additional impacts analysis or Class I 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.

3.4 Endangered Species Act and National Historic Preservation Act Analysis

Analyses of any potential impacts of the proposed project with respect to the Endangered Species Act (ESA) and National Historic Preservation Act (NHPA) will be addressed in separate submittals to U.S. EPA Region 6.

4.0 Best Available Control Technology (BACT)

Under the Clean Air Act (CAA) and applicable regulations, a PSD permit must contain emissions limitations based on application of BACT for each regulated NSR pollutant. This permit application is for a PSD permit for greenhouse gas (GHG) emissions associated with the WPH. GHG emissions of CO_2 are produced by the boilers due to combustion of fuels that contain carbon. In addition, small quantities of CH_4 and N_2O that do not undergo complete combustion are also emitted from the boilers. Some N_2O and CO_2 emissions are also produced by the Selective Non-Catalytic Reduction (SNCR) technology proposed to control NO_x emissions.

The PSD definition of BACT from 40 CFR Part 52, §52.21(b)(12) is shown below.

Best available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

This project involves the installation of NO_x emissions controls for the WPH waste fuel boilers as required by the Consent Decree and Texas Compliance Agreement and modifications to the WPH boilers. The WPH boilers are subject to RCRA permit requirements for Boilers and Industrial Furnaces (BIFs) burning hazardous waste, as well as 40 CFR Part 63, Subpart EEE requirements for Hazardous Waste Combustors. These requirements affect the manner in which the WPH boilers must be operated, including waste destruction efficiency and boiler tuning and optimization. The fundamental purpose of the WPH boilers is to combust waste fuels from process operations at the site and, in so doing, to recover the energy value of those fuels. As a result, consideration of off-site disposal or on-site flaring of those fuels, and instead firing additional natural gas or other fuels in the boilers would result in fundamentally "redesigning the source." As explained below, control measures that would require fundamental redesign of the source are not required to be considered in a BACT analysis.

In *Sierra Club v. EPA*, 499 F3d 653 (7th Cir. 2007), Prairie State Generating Company proposed to build a "mine-mouth" coal-fired power plant, meaning that the plant was purposely sited at the location of a coal seam so that the plant could simply build a conveyer belt system to take the coal a half mile to the plant. The coal at the proposed location was high-sulfur coal, so Sierra Club sued claiming that EPA's BACT determination was deficient because the Agency should have required the plant to burn low sulfur coal. Burning low-sulfur coal would have required coal to be brought in from more than a thousand miles away, and would have required changes to the design of the plant.

The court rejected Sierra Club's claim, and upheld EPA's determination that while clean fuels is something that must be considered in the BACT analysis, to require Prairie to use low-sulfur coal from Montana or Wyoming would be a fundamental change to the "mine-mouth" nature of the plant, and hence need not be considered in the BACT analysis. INVISTA believes that this case is analogous to the WPH project and that to require Victoria to burn natural gas, other than as supplemental fuel, or another fuel such as biomass in the WPH boilers would call for a fundamental redesign of the boilers, and hence need not be considered in the BACT analysis.

The fundamental redesign concept is also expressed in numerous EAB opinions and EPA guidance. For example, in EPA's March 2011 "PSD and Title V Permitting Guidance for Greenhouse Gases," at 27, EPA states:

"The CAA includes "clean fuels" in the definition of BACT. (footnote omitted). Thus, clean fuels which would reduce GHG emissions should be considered, but EPA has recognized that the initial list of control options for a BACT analysis does not need to include "clean fuel" options that would fundamentally redefine the source. Such options include those that would require a permit applicant to switch to a primary fuel (i.e., coal, natural gas, or biomass) other than the type of fuel that an applicant proposes to use for its primary combustion process. For example, when an applicant proposes to construct a coal-fired steam electric generating unit, EPA continues to believe that permitting authorities can show in most cases that the option of using natural gas as a primary fuel would fundamentally redefine a coal-fired electric generating unit. (footnote omitted)"

In this case, in addition to being a fundamental redesign of the source, off-site disposal and on-site flaring of the fuels generated by the process units would result in burning additional natural gas to produce the steam required at the site. Burning larger quantities of natural gas in lieu of burning the fuels from process operations would result in an overall increase in GHG emissions and, therefore, would not be considered BACT.

In accordance with EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases," the BACT Analysis should follow a five-step "top-down" approach consisting of the following: 1) Identify all available control options; 2) Eliminate technically infeasible options; 3) Rank the remaining controls; 4) Beginning with the top-ranked option, evaluate the economic, energy, and environmental impacts to determine whether the option is not achievable and, if so, repeat this step for lower ranked options until an achievable option is determined; and 5) Select the highest ranked achievable option as BACT.

4.1 BACT for the Boilers

4.1.1 Identify All Available Control Options for Boiler BACT for GHG

Based on a query of EPA's RACT/BACT/LAER Clearinghouse (RBLC) in February 2012, there are no BACT entries for GHG emissions from boilers firing the various types of fuels that are fired in the INVISTA Victoria WPH boilers. With regard to GHG emissions in general, the RBLC query indicated that BACT is typically one or more of the following: proper operation, good combustion practices, energy integration, good operation practices to maintain low levels of fuel consumption, or no control method. The most comprehensive documentation for GHG BACT identified was EPA's guidance document "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers," October 2010. INVISTA examined this guidance document and other sources. Based on all of these sources, as well as INVISTA process knowledge, the following available control options have been identified for the INVISTA WPH boilers.

Summary of Available GHG Emission Reduction Measures

GHG Emission Reduction Measure	Description
Design Energy Efficiency Measures	Measures that may be included in the design of and subsequent modifications to the boilers to increase combustion efficiency or the recovery of available heat energy.
Operational Energy Efficiency Measures	Methods of operating the boilers so as to maintain optimal energy efficiency and energy recovery.
Carbon Capture and Storage (CCS)	Systems that capture CO_2 from the exhaust and transfer the CO_2 to permanent storage.

The following options already have been implemented by INVISTA, or will be implemented as part of this project.

Design Energy Efficiency Measures

- Replace/Upgrade Burners
- Economizer
- Air Preheater
- Insulation and Insulating Jackets
- Capture energy from boiler blowdown
- Condensate return system
- Reduce slagging and fouling of heat transfer surfaces

Operational Energy Efficiency Measures

- Tuning
- Optimization
- Instrumentation & Controls
- Reduce air leakages
- Reduce steam trap leaks

Per the prior discussion, the following measures that were listed in EPA's guidance on available and emerging technologies for reducing GHG emissions from boilers will not be addressed further because they would require the existing WPH boilers to be fundamentally redesigned and are thus outside the scope of the project.

- Alternative fuels—biomass; not applicable because the boilers are liquid waste and process gas fueled boilers.
- Fuel switching – to natural gas, for example; not applicable because the boilers are liquid waste and process gas fueled boilers, although natural gas is used as supplemental fuel.
- Create turbulent flow within firetubes; not applicable because the WPH boilers are water tube boilers.
- Combined heat and power; not applicable because the WPH boilers are designed and operated to provide steam to the site's process units and not to generate electricity.

4.1.2 Eliminate Technically Infeasible Options for Boiler BACT

In the second step of the top-down BACT analysis, the technically infeasible options are eliminated. As explained in EPA's 1990 Draft New Source Review Manual at B.17,

"[I]f the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible. For control technologies that are not demonstrated in the sense indicated above the analysis is somewhat more involved."

"Two key concepts are important in determining whether an undemonstrated technology is feasible: 'availability' and 'applicability.' . . . . a technology is considered 'available' if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is 'applicable' if it can reasonably be installed and operated on the source type under construction. A technology that is available and applicable is technically feasible."

EPA's 1990 Draft New Source Review Manual further explains, at B.18, that, "Commercial availability by itself, however, is not necessarily sufficient for concluding a technology to be applicable and therefore technically feasible. Technical feasibility . . . also means a control option may reasonably be deployed on or 'applicable' to the source type under consideration."

The following GHG emissions reduction measure has been determined to be technically infeasible.

Carbon Capture and Storage (CCS)

CCS is not a technically feasible control technology for the WPH boilers. First, CCS has not been installed and operated successfully (i.e., demonstrated) on a source similar to the WPH boilers (e.g., an integrated hazardous waste boiler burning process streams for energy recovery). Second, although CCS is considered an "available" technology, as that term is used for the purpose of a PSD BACT analysis, because it has the potential for practical application to the control of CO_2 emissions from industrial boilers, CCS is not "applicable" to the INVISTA Victoria WPH boilers because there is no specific evidence that there is a commercially available CCS system of the scale that would be required to control the CO_2 emissions from the WPH boilers.

This conclusion is supported by the *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010. The Task Force was composed of 14 Executive Departments and Federal Agencies and was co-chaired by the Department of Energy (DOE) and the Environmental Protection Agency (EPA). The purpose of the Task Force was to propose "a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within ten years." The Task Force report summarized the status of CCS technology, listed difficulties associated with implementing the technology, and stated that, although CCS technology is available, it is not ready for widespread implementation. Difficulties discussed in the report that would be applicable to this project include:

- A high volume of gas would have to be treated due to the low CO_2 concentration in the exhaust stream (approximately three to ten percent by volume in the WPH boiler exhaust);
- The boiler exhaust gas is at a low pressure (additional pressure would be required to process the exhaust in the CO_2 capture system);
- Contaminants in the exhaust gas, including oxides of nitrogen, particulate matter, and sulfur dioxide, could degrade the materials used to capture the CO_2; and
- The captured CO_2 would have to be compressed to the high CO_2 pipeline pressure.

In addition to the difficulties identified in the Task Force report, the methods of capturing CO_2 from the exhaust are not technically feasible for the WPH boilers. These methods include scrubbing, O_2/CO_2 Recycle, and membrane contactors. Each of these methods is discussed below.

Scrubbing: When utilizing a scrubbing system (i.e. amine scrubbing) CO_2 is captured through the use of a solvent to absorb CO_2 from the exhaust stream. Additional energy is required to compress the exhaust so that the stream can be fed into the scrubber. Also, a large quantity of steam is required to regenerate the scrubbing solvent. In INVISTA Victoria's case, the steam required for solvent regeneration would make it necessary for the site to install an auxiliary boiler or another source of additional steam. Generating that steam would create additional emissions of GHGs and other criteria air pollutants, and would consume additional natural gas. Although a scrubber can capture as much as 90% of the exhaust stream CO_2, after accounting for additional CO_2 that would be produced to operate the scrubbing system and to convey the captured CO_2 to storage, the net percentage of CO_2 emissions avoided would be less than 90%. In the case of the WPH boilers, the scrubbing solvent and the scrubbing system would be degraded by the contaminants in the fuels from the process units. A CO_2 scrubber system is not a demonstrated technology for integrated hazardous waste boilers, such as the WPH boilers.

O_2/CO_2 Recycle: An alternative to capturing CO_2 through the use of scrubbing would be to replace combustion air with oxygen, and use flue gas recirculation to limit combustion temperatures. This method, known as "O_2/CO_2 recycle," significantly increases the CO_2 concentration in the exhaust, so that the exhaust stream can be conveyed to storage (sequestration) as is, or after only moderate additional purification, for example through a flash unit. In the case of the WPH boilers, due to the presence of significant concentrations of fuel-bound nitrogen and other constituents in the fuels from the site's process units, capturing and sequestering the entire exhaust stream without further treatment is not technically feasible.

Membrane Contactor: Another technology for capturing CO_2 involves the use of membrane contactors. In a system utilizing this technology, CO_2 would pass through the membrane into a solvent with high selectivity for CO_2. The use of this technology on exhaust streams from boilers combusting the variety of streams that are combusted in the INVISTA WPH boilers has not been demonstrated and, due to the constituents of the process waste streams combusted (i.e., ash and other particulates), the membrane may become plugged or coated with materials that would degrade the CO_2 flux rate through the membranes. Therefore, membrane technology is not a technically feasible technology for the WPH boilers.

4.1.3 Rank the Remaining Options for Boiler BACT

In the third step of the top-down BACT analysis, the remaining options for boiler BACT are ranked. As explained in Section 4.1.2, CCS is not technically feasible for the WPH boilers. Nevertheless, INVISTA ranks it here and addresses the associated economic, energy, and environmental impacts in the next section. The CCS cost analysis is based on the assumption that, if technically feasible, CCS could potentially capture and store up to approximately 90% of the CO_2 emissions generated by the WPH boilers. INVISTA does not rank the energy efficiency measures identified above because INVISTA proposes to adopt them.

4.1.4 Evaluate Economic, Energy, and Environmental Impacts for Boiler BACT

CCS is evaluated below for economic, energy, and environmental impacts.

Economic Evaluation

In addition to its technical infeasibility, INVISTA proposes rejecting CCS on the basis of economic infeasibility. Carbon capture and storage would require that the CO_2 in the boiler exhaust streams be captured, compressed and conveyed to a suitable long-term CO_2 storage facility. The economic feasibility of CCS has been evaluated based on the scrubbing method of CO_2 capture.

In addition to a CO_2 capture system, CCS would also require the installation of a large pipeline that would convey the captured CO_2 to an existing pipeline or to a suitable long-term CO_2 storage facility. Potentially suitable storage facilities include deep un-minable coal seams, deep saline formations, depleted oil basins, depleted gas fields, and oil fields where CO_2 can be injected for the purpose of enhanced oil recovery (EOR). No long-term CO_2 storage facilities are located near the INVISTA Victoria site. The Denbury Green Pipeline, the nearest commercially available CO_2 pipeline, and the Denbury West Hasting oil field where CO_2 could be used for EOR, are located more than 100 miles from the INVISTA Victoria site. Further evaluation of CCS is based on the assumption that the Denbury System will accept the captured CO_2 from this project.

INVISTA has reviewed current cost information for CCS including the "Report of the Interagency Task Force on Carbon Capture and Storage," the U.S. Department of Energy National Energy Technology Laboratory (NETL) document "Estimating Carbon Dioxide Transport and Storage Costs, and a document regarding the industrial design and optimization of CO_2 capture, dehydration, and compression facilities.[1] Based on these documents, annualized and capital costs of CCS have been developed.

[1] Aboudheir, A. and G. McIntyre, "Industrial Design and Optimization of CO_2 Capture, Dehydration, and Compression Facilities."

Annualized Costs: The total annualized cost of CO_2 capture, transport and storage associated with the WPH project is estimated to be in the range of $57 million to $134 million. The CO_2 annualized capture, transport and storage cost analysis is provided in the table entitled "Approximate Annual Costs of Carbon Capture, Transport and Storage" in Appendix D.

Capital Cost: The capital cost of CCS for the WPH boiler project has been estimated to be in the range of approximately $293 million to $375 million, including approximately $219 million to $300 million for CO_2 capture and approximately $75 million for a pipeline to connect to the Denbury pipeline. Detailed calculations and references are provided in Appendix D.

Economic Infeasibility: In order to determine the economic feasibility of CCS, the estimated annualized and capital costs of CCS are compared to the projected WPH boiler capital cost. The annualized CCS cost has been estimated to be more than 150% of the estimated WPH boiler project capital cost. The capital cost of CCS has been estimated to be more than four times the estimated WPH boiler project capital cost. The cost of the capture system alone has been estimated to be more than three times the estimated WPH boiler project capital cost. Therefore, INVISTA submits that CCS based on capture costs alone is not an economically feasible control option for the proposed project. Additional transportation and storage costs would make CCS even less economically feasible or reasonable.

Energy and Environmental Impacts

A CCS system would also cause significant adverse energy and environmental impacts. The scrubbing system used to capture CO_2 emissions would consume large amounts of energy. As previously discussed, a large quantity of steam would also be required to regenerate the scrubbing solvent. Generating that steam would create additional emissions of GHGs and other criteria air pollutants, 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.

4.1.5 Select BACT for the Boilers

The WPH boilers already employ energy efficiency measures. Refurbishing and modernizing the boilers will restore and improve the energy efficiency measures that are already in place. INVISTA proposes the following energy efficiency measures that already have been implemented, or that will be implemented as part of this project, as BACT for the GHG emissions from the WPH boilers.

Design Energy Efficiency Measures

Energy Efficiency Measure	Description
Replace/Upgrade Burners	The WPH boilers must provide the required destruction efficiency for BIF units when combusting the waste fuels from the process units. This requirement creates certain constraints with respect to the burners used in the boilers. Additionally, to achieve BACT for NO_x emissions, as required under Texas minor NSR rules, low-NO_x burners will be installed as part of this project. Although INVISTA plans to seek low-NO_x burners that would maximize energy efficiency for that type of burner, low-NO_x burners may be less energy efficient from a GHG perspective than typical burners that do not reduce NO_x emissions. EPA has indicated that, to the extent that criteria pollutant emission rates and GHG emission rates cannot be concurrently minimized, minimization of criteria pollutants should take precedence. This is especially true here, where the main purpose of the project is to increase the control of NO_x emissions from the WPH boilers. Therefore, INVISTA proposes to install energy efficient low-NO_x burners that are capable of properly destructing the waste fuels that will be combusted in the WPH boilers.
Economizer	The WPH boilers are not equipped with economizers, but stage heaters that pre-heat boiler feed water with excess steam are utilized when excess steam is available.
Air Preheater	The WPH boilers are equipped with air preheaters that reduce the energy required to heat the combustion air to the required combustion temperature.
Insulation and Insulating Jackets	The WPH boilers are insulated to reduce heat loss from the boilers and improve thermal efficiency. Improving thermal efficiency results in decreased supplemental natural gas requirements and decreased GHG emissions. Insulation will be replaced as necessary.
Capture energy from boiler blowdown	INVISTA already implements this energy saving measure by recovering energy from the boiler blowdown to reduce the quantity of supplemental natural gas required and, therefore, reduce GHG emissions.

Energy Efficiency Measure	Description
Condensate return system	The condensate return system includes steam traps and return headers for high-pressure systems.
Reduce slagging and fouling of heat transfer surfaces	Soot blowers are utilized and maintained to help minimize heat transfer surface fouling.

Operational Energy Efficiency Measures

Energy Efficiency Measure	Description
Tuning	Boiler operation will be tuned upon start-up after the project is implemented. The boilers will be tuned by monitoring CO and O_2 concentrations and boiler operation will be adjusted as necessary. The fuel flow rates to the boilers are monitored and adjusted as necessary to maintain operating conditions that optimize energy efficiency while ensuring adequate destruction of the waste fuels to meet BIF unit requirements. Periodic inspections of the boilers are also conducted to detect and correct conditions that would reduce energy efficiency, when necessary.
Optimization	The boiler operation is optimized in order to reduce energy consumption while ensuring adequate destruction of the waste fuels to meet requirements applicable to BIF units.

Energy Efficiency Measure	Description
Instrumentation & Controls, Including Oxygen Trim Control	The WPH boilers are equipped with process control technology to monitor and control boiler operating parameters such as excess oxygen, carbon monoxide, pressure, combustion air flow, fuel flow, and temperature to optimize boiler energy efficiency while ensuring destruction of waste fuels in accordance with RCRA permit requirements. In addition, the boilers are equipped with safety systems, including automatic waste fuel cut-off in the event that boiler operation falls outside of specified limits. Oxygen analyzers and excess oxygen automated controls, are utilized, as necessary, to optimize boiler efficiency. Oxygen analyzers and excess oxygen automated controls will minimize excess oxygen, while ensuring there is sufficient oxygen for complete combustion and safe operation. Minimizing excess oxygen will increase boiler energy efficiency and reduce the usage of supplemental natural gas.
Reduce Air Leakages	The preheaters are maintained to reduce air leakage. In addition the firebox is periodically monitored to minimize leakage and heat loss. Reduced air leakage improves boiler thermal efficiency.
Reduce Steam Trap Leaks	INVISTA has a steam trap program on site to detect and repair steam trap leaks and avoid the energy losses associated with unrepaired leaking stream traps.

INVISTA proposes to employ the measures described in the tables above to maximize the energy efficiency of the boilers and, as a result, to minimize GHG emissions. INVISTA proposes to implement these measures through compliance with an annual CO_2e emission limit of 1,371,684 TPY. This quantity of CO_2e emissions is based on the projected annual average boiler efficiency and the projected quantity of each fuel on an annual basis.

The WPH boilers combust a variety of fuels from the site's process units as described in Section 2.0. The fuels from the site's process units include both liquids and gases. The gaseous fuels include both high and low BTU streams. In addition, the boilers combust natural gas to the extent necessary to provide adequate steam production for the site. There is a wide range in the potential GHG emissions associated with the liquid fuels, the low and high-BTU gaseous fuels, and natural gas. During any short-term time period, many different combinations of fuels, with varying compositions, could be burned depending upon the operating rate of the site process units. As a result, GHG emissions can vary significantly on a short-term basis making it difficult to develop a meaningful GHG emission limit for any time period less than twelve months. However, on an annual basis the quantity of each fuel burned and the total GHG emissions are more predictable.

4.2 BACT for Fuel System Fugitive Emissions

Some of the fuels associated with the WPH boilers contain CH_4, CO_2, and N_2O. Based on a query of EPA's RACT/BACT/LAER Clearinghouse (RBLC) in February 2012, BACT for GHG fugitive emissions is a gas and leak detection system or a leak detection and repair program. INVISTA proposes that monitoring and repairing fuel system components that contain significant concentrations of CH_4 under a TCEQ 28VHP LDAR program, as applicable, will be BACT. In addition, INVISTA proposes to monitor components on fuel systems that contain significant concentrations of GHG, but that are not monitored under 28VHP, by means of weekly walkthrough audio/visual/olfactory (AVO) inspection methods. INVISTA proposes that these methods will meet BACT.

5.0 Basis of Emission Calculations

5.1 Boilers (FIN 15BLR001, 15BLR002, 15BLR003 and 15BLR004)

Projected actual emission (PAE) rates of GHG from the boilers were calculated based on the projected boiler fuel firing rates and GHG emission factors associated with those fuels. Baseline actual emission (BAE) rates were calculated based on actual fuel flow rates and GHG emission factors associated with each of the fuels. The project emission increases were calculated by subtracting the BAE rates from the PAE rates.

The PAE rates of CO_2 were calculated based on projected flow rates and the typical carbon content of each fuel stream, with 100% conversion of carbon to CO_2 assumed through combustion. For natural gas, methane (CH_4) and nitrous oxide (N_2O) emissions were calculated based on projected flow rates and the CH_4 and N_2O factors for natural gas combustion from 40 CFR Part 98, Subpart C, Table C-2. For other fuel streams, CH_4 and N_2O emissions were calculated based on the projected flow rate and the CH_4 and N_2O content of each fuel stream and the boilers' destruction efficiencies for CH_4 and N_2O.

In addition, the SNCR technology used to control NO_x emissions is expected to produce N_2O emissions. The N_2O emission calculations are based on the emission rates that are predicted to occur after the installation of SNCR on all four boilers. EPA's Air Pollution Control Technology Fact Sheet for SNCR (EPA-452/F-03-031) states that, at most, 10% of the NO_x reduced in urea-based SNCR will be converted to N_2O. To be conservative, the PAE N_2O emission calculations in this application are based on 10% of the SNCR NO_x reduction being converted to N_2O. SNCR NO_x reduction efficiency is estimated to be 27-45% for the WPH boilers. For the purpose of calculating projected actual N_2O emissions, the annual average SNCR NO_x reduction has been estimated at 45% to provide a conservative basis for N_2O emissions. This estimated SNCR NO_x reduction does not represent a limit on the actual SNCR NO_x reduction that the WPH boiler SNCR systems will be required to achieve.

INVISTA has also considered the potential formation of CO_2 from urea injection that would be used in SNCR systems. To be conservative, CO_2 emissions are estimated based on conversion of 100% of the carbon in urea being converted to CO_2 and on projected urea injection rates.

The BAE rates were calculated in the same manner as PAE rates, except that actual fuel flow rates were used. Additionally, no SNCR-related emissions were included in the BAE rates because the boilers did not have SNCR systems during the baseline time period.

The flow rates and concentrations shown in the calculations are typical values. Although individual stream flow rates and concentrations may vary higher or lower than the typical values in the calculations, the total annual GHG emissions will not exceed those represented in this permit application. The values shown on the Table 1(a) are the maximum expected annual GHG emissions from the WPH Boilers. The detailed emissions calculations in Section 6 show the emission bases, but the flow rates, concentrations, and other representations in the detailed calculations are not meant to be binding representations. Though the flow rates of the streams are monitored for informational purposes, the total annual GHG emission rate from the four WPH Boilers (1,371,684 TPY) is the only factor that INVISTA proposes to use for demonstrating compliance with the permit.

5.2 Fuel System Fugitive Emissions (FIN 15FUG; EPN 15FUG)

Fuel system fugitive components include new valves, pumps, flanges, and other potential leaking components. Emissions from these sources were calculated using estimated component counts for the various streams associated with the fuel system piping. SOCMI without ethylene emission factors from the TCEQ fugitive emission guidance document were used to estimate fugitive GHG emissions. Emission reduction credits for the TCEQ 28VHP LDAR program (described Appendix D) have been applied where appropriate. The GHG emissions are estimated based on the weight concentration of each GHG in each stream.

6.0 Emission Calculations

TABLE 1: SUMMARY OF EMISSION FACTORS

Fuel	Carbon Content Factors (lb Carbon/ lb Fuel)	CO_2 Emission Factors Due to Combustion (lb CO_2/ lb Fuel)	CO_2 Emission Factors Due to Urea Use in SNCR (lb/lb Fuel)	CH_4 Emission Factors (lb/lb Fuel)	N_2O Emission Factors Due to N_2O in Fuel (lb/lb Fuel)	N_2O Emission Factors Due to NOx Reduction by SNCR (lb/lb Fuel)	CO_2e Total Emission Factors (lb/lb Fuel)
LIQUID FUELS	0.6190	2.2681	0.002062	0	0	0.0002750	2.3554
GASEOUS FUELS (Low BTU)	0.0387	0.1418	0.000493	6.499E-10	2.34E-04	0.0000657	0.2352
GASEOUS FUELS (High BTU)	0.2586	0.9476	0.001406	2.713E-06	0	0.0001875	1.0072
NATURAL GAS (including MS REGEN)	0.7299	2.6744	0.000861	4.495E-05	4.49E-06	0.0001148	2.7132

Note: The values shown represent a potential scenario, are used to estimate maximum emission rates, and are not intended to be permit limits. The permit limits are the emission rate limits. The estimated ratio of urea to NOx reduced, the SNCR NOx reduction as a percentage of the pre-control NOx emission rate, and the N_2O due to SNCR NOx reduction have all been estimated so as to provide conservative (i.e., reasonably high) emission rate estimates.

Sample Calculations:

CO2 factor, low-BTU gas fuel combustion =	0.0387 lbs of carbon / lb fuel	lb-mole of carbon / 12.011 lbs of carbon	1 lb-mole CO2 / 1 lb-mole of carbon	44.01 lbs CO2 / 1 lb-mole CO2	=	0.1418 lbs CO2/lb fuel
CO2 from SNCR urea for low-BTU gas fuels =	0.000687 lbs NOx controlled / lb fuel	1 lb-mole NOx / 46.006 lbs of NOx	0.75 lb-mole CO2 / 1 lb-mole NOx	44.01 lbs CO2 / 1 lb-mole CO2	=	0.000493 lbs CO2/lb fuel
CH4 factor for low-BTU gas fuels =	2.21E-06 kg CH4 / MMBTU of low-BTU gas fuel	2.2046 lbs CH4 / 1.0000 kg CH4	133.5 Btu / lb of low-BTU gas fuel	1 MMBTU / 1,000,000 BTU	=	6.499E-10 lbs CH4/lb fuel
N2O factor for low-BTU gas fuels =	0.795 kg N2O / MMBTU of low-BTU gas fuel	2.2046 lbs N2O / 1.0000 kg N2O	133.5 Btu / lb of low-BTU gas fuel	1 MMBTU / 1,000,000 BTU	=	2.338E-04 lbs N2O/lb fuel
N2O from SNCR for low-BTU gas fuels =	0.000687 lbs NOx controlled / lb fuel	1 lb-mole NOx / 46.006 lbs of NOx	0.1 lb-mole N2O / 1 lb-mole NOx	44.013 lbs of N2O / 1 lb-mole N2O	=	0.0000657 lbs N2O/lb fuel

TABLE 2: SUMMARY OF PROPOSED WPH ANNUAL AVERAGE PARAMETERS AND EMISSION RATES

Fuel	Scenario Annual Average Flow Rates to Boilers (Mpph)	CO_2 Emissions Due to Combustion (TPY)	CO_2 Emissions Due to Urea in the SNCR (TPY)	CO_2 Total Emissions (TPY)	CH_4 Emissions (TPY)	N_2O Emissions Due to Fuels (TPY)	N_2O Emissions Due to SNCR (TPY)	N_2O Total Emissions (TPY)	CO_2e Emissions (TPY)	GHG Emissions (TPY)
LIQUID FUELS	41.62	413,467	376	413,843	0	0	50.134	50.13	429,385	413,893
GASEOUS FUELS (Low BTU)	170.08	105,666	367	106,033	0.00048	174.18	48.972	223.16	175,212	106,257
GASEOUS FUELS (High BTU)	28.54	118,461	176	118,636	0.339	0	23.442	23.44	125,910	118,660
NATURAL GAS (including MS REGEN)	53.95	632,013	203	632,217	10.62	1.06	27.123	28.19	641,177	632,256
Total Projected Actual Emission (PAE) Rates		**1,269,607**	**1,122**	**1,270,730**	**10.961**	**175.25**	**149.67**	**324.92**	**1,371,684**	1,271,066
Global Warming Potential Factor				1	21			310		
CO_2e (tons/yr)				1,270,730	230			100,724	1,371,684	
CO_2e (metric tons/yr)				1,152,799	209			91,376	1,244,384	
Boiler Baseline Actual Emission (BAE) Rates (September 2009 - August 2011)				642,708	5.272			108.65	676,500	642,822
PAE Rates minus BAE Rates									695,184	628,243
Fugitive emissions Increase				1.66	10.65			2.37	959	15
Total Project Emissions Increase									696,144	628,258
PSD Significance Level									75,000	

Note: The values shown represent a potential scenario, are used to estimate maximum emission rates, and are not intended to be permit limits. The permit limits are the emission rate limits. The estimated ratio of urea to NOx reduced, the SNCR NOx reduction as a percentage of the pre-control NOx emission rate, and the N2O due to SNCR NOx reduction have all been estimated so as to provide conservative (i.e., reasonably high) emission rate estimates.

Note: Mpph = 1000 pounds per hour, TPY = tons per year, and M lbs = 1000 pounds

Sample Calculations:

CO2 from combustion of low-BTU gas fuels =	170.08 M lbs of fuel / hr	1000 lbs / M lbs	0.1418 lbs CO2 / lb of fuel	8760 hr / yr	1 ton / 2000 lbs	=	105,666 tons/yr
CO2 from SNCR urea for low-BTU gas fuels =	170.08 M lbs of fuel / hr	1000 lbs / M lbs	0.000493 lbs CO2 / lb of fuel	8760 hr / yr	1 ton / 2000 lbs	=	367 tons/yr
CH4 emissions from low-BTU gas fuels =	170.08 M lbs of fuel / hr	1000 lbs / M lbs	6.499E-10 lbs CH4 / lb of fuel	8760 hr / yr	1 ton / 2000 lbs	=	0.00048 tons/yr
N2O emissions from low-BTU gas fuels =	170.08 M lbs of fuel / hr	1000 lbs / M lbs	2.338E-04 lbs N2O / lb of fuel	8760 hr / yr	1 ton / 2000 lbs	=	174.18 tons/yr
N2O from SNCR for low-BTU gas fuels =	170.08 M lbs of fuel / hr	1000 lbs / M lbs	0.0000657 lbs N2O / lb fuel	8760 hr / yr	1 ton / 2000 lbs	=	48.97 tons/yr

EXISTING WEST POWERHOUSE GHG FUGITIVE EMISSIONS

	Streams			Fuels (Low BTU)	Fuels (High BTU)	Natural Gas (Including MS Regen)
	Monitoring Program			28VHP Monitoring Where Applicable	28VHP or Annual Monitoring Where Applicable	28VHP Monitoring Where Applicable
Emission Source	SOCMI w/out C2 Factor[1] (lb/hr/ source)	28VHP Control Factor [2]	Annual 500 ppm Monitoring Control Factor [3]	Source Count	Source Count	Source Count
Valves (light liquid)	0.0035	97%	75%	39	28	24
Valves (gas stream)	0.0089	97%	75%	341	150	589
Pumps (light liquid)	0.0386	85%	75%	3	4	0
RV (gas)	0.2293	97%	75%	1	0	12
Flanges/Conn (light liquid)	0.0005	30%	75%	167	66	60
Flanges/Conn (vapor)	0.0029	30%	75%	902	352	1729
Closed Vent Flange/Conn (gas)	0.0029	30%	75%	0	0	418
TOTALS				1453	600	2832

		Fuels (Low BTU)	Fuels (High BTU)	Natural Gas (Including MS Regen)	Total
Emission Source		Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)
Valves (light liquid)		0.075	0.098	0.003	0.176
Valves (gas stream)		2.517	0.903	0.157	3.578
Pumps (light liquid)		0.116	0.1544	0.000	0.270
RV (gas)		0.229	0	0.083	0.312
Flanges/Conn (light liquid)		0.073	0.033	0.021	0.127
Flanges/Conn (vapor)		2.460	0.775	3.510	6.74
Closed Vent Flange/Conn (gas)		0.000	0.000	0.849	0.849
TOTALS		5.470	1.964	4.622	12.06

SPECIATION (Effective Weighted-Average Compositions):

Chemical	Weight %	Weight %	Weight %
N_2O	33.38	0	0
CO_2	4.94	5.94	4.81
CH_4	0.013	4.76	100*

*To be conservative, natural gas is assumed to contain up to 100% methane.

SPECIATED EMISSIONS (Average Annual):

CHEMICAL	Emissions (ton/yr)	Emissions (ton/yr)	Emissions (ton/yr)	Total (ton/yr)
N_2O	8.00	0	0	8.00
CO_2	1.184	0.511	0.974	2.67
CH_4	0.003	0.409	20.24	20.66
CO_2e				2916.1

Notes:

(1) Emission Factors are from the TCEQ Technical Guidance Document "Equipment Leak Fugitives," dated October 2000

(2) Pumps, valves, and other affected components will be monitored in accordance with a 28VHP LDAR program. Therefore, the 28VHP control factors from the TCEQ Document Technical Guidance "Equipment Leak Fugitives," dated October 2000 are used. A weekly walkthrough inspection will be done on flanges/connectors

(3) For components not subject to 28VHP but monitored annually at a 500 ppmv leak definition, a 75% control credit is applied per the TCEQ Technical Guidance Document "Equipment Leak Fugitives," dated October 2000, and related guidance from TCEQ. Under the alternative 28VHP program, the HON monitoring frequency may be used. Therefore, the lower control factor for annual monitoring is used.

(4) The Mole Sieve Gas ADN counts include the entire natural gas system for the WPH Boilers (except for the C12 and pilot gas systems). The Mole Sieve Gas ADN and Mole Sieve Gas C12 streams are primarily natural gas with small amounts of the material purged from the mole sieves.

PROPOSED WEST POWERHOUSE GHG FUGITIVE EMISSIONS

	Streams			Fuels (Low BTU)	Fuels (High BTU)	Natural Gas (Including MS Regen)
	Monitoring Program			28VHP Monitoring Where Applicable	28VHP or Annual Monitoring Where Applicable	28VHP Monitoring Where Applicable
Emission Source	SOCMI w/out C2 Factor(1) (lb/hr/ source)	28VHP Control Factor (2)	Annual 500 ppm Monitoring Control Factor (3)	Source Count	Source Count	Source Count
Valves (light liquid)	0.0035	97%	75%	73	70	30
Valves (gas stream)	0.0089	97%	75%	545	376	963
Pumps (light liquid)	0.0386	85%	75%	4	10	0
RV (gas)	0.2293	97%	75%	2	0	15
Flanges/Conn (light liquid)	0.0005	30%	75%	298	166	75
Flanges/Conn (vapor)	0.0029	30%	75%	1457	882	2167
Closed Vent Flange/Conn (gas)	0.0029	30%	75%	0	0	1046
TOTALS				2379	1504	4296

		Fuels (Low BTU)	Fuels (High BTU)	Natural Gas (Including MS Regen)	Total
Emission Source		Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)
Valves (light liquid)		0.099	0.245	0.003	0.347
Valves (gas stream)		3.556	2.259	0.257	6.071
Pumps (light liquid)		0.154	0.386	0.000	0.540
RV (gas)		0.459	0	0.103	0.562
Flanges/Conn (light liquid)		0.122	0.083	0.026	0.232
Flanges/Conn (vapor)		3.836	1.940	4.399	10.17
Closed Vent Flange/Conn (gas)		0.000	0.000	2.123	2.123
TOTALS		8.226	4.913	6.912	20.05

SPECIATION (Effective Weighted-Average Compositions):

Chemical	Weight %	Weight %	Weight %
N_2O	28.77	0	0
CO_2	4.42	5.93	4.81
CH_4	0.017	4.76	100*

*To be conservative, natural gas is assumed to contain up to 100% methane.

SPECIATED EMISSIONS (Average Annual):

CHEMICAL	Emissions (ton/yr)	Emissions (ton/yr)	Emissions (ton/yr)	Total (ton/yr)
N_2O	10.37	0	0	10.37
CO_2	1.594	1.277	1.455	4.33
CH_4	0.006	1.025	30.28	31.31
CO_2e				3875.5

Notes:

(1) Emission Factors are from the TCEQ Technical Guidance Document "Equipment Leak Fugitives," dated October 2000.

(2) Pumps, valves, and other affected components will be monitored in accordance with a 28VHP LDAR program. Therefore, the 28VHP control factors from the TCEQ Document Technical Guidance "Equipment Leak Fugitives," dated October 2000, are used. A weekly walkthrough inspection will be done on flanges/connectors

(3) For components not subject to 28VHP but monitored annually at a 500 ppmv leak definition, a 75% control credit is applied per the TCEQ Technical Guidance Document "Equipment Leak Fugitives," dated October 2000, and related guidance from TCEQ. Under the alternative 28VHP program, the HON monitoring frequency may be used. Therefore, the lower control factor for annual monitoring is used.

(4) The Mole Sieve Gas ADN counts include the entire natural gas system for the WPH Boilers (except for the C12 and pilot gas systems). The Mole Sieve Gas ADN and Mole Sieve Gas C12 streams are primarily natural gas with small amounts of the material purged from the mole sieves.

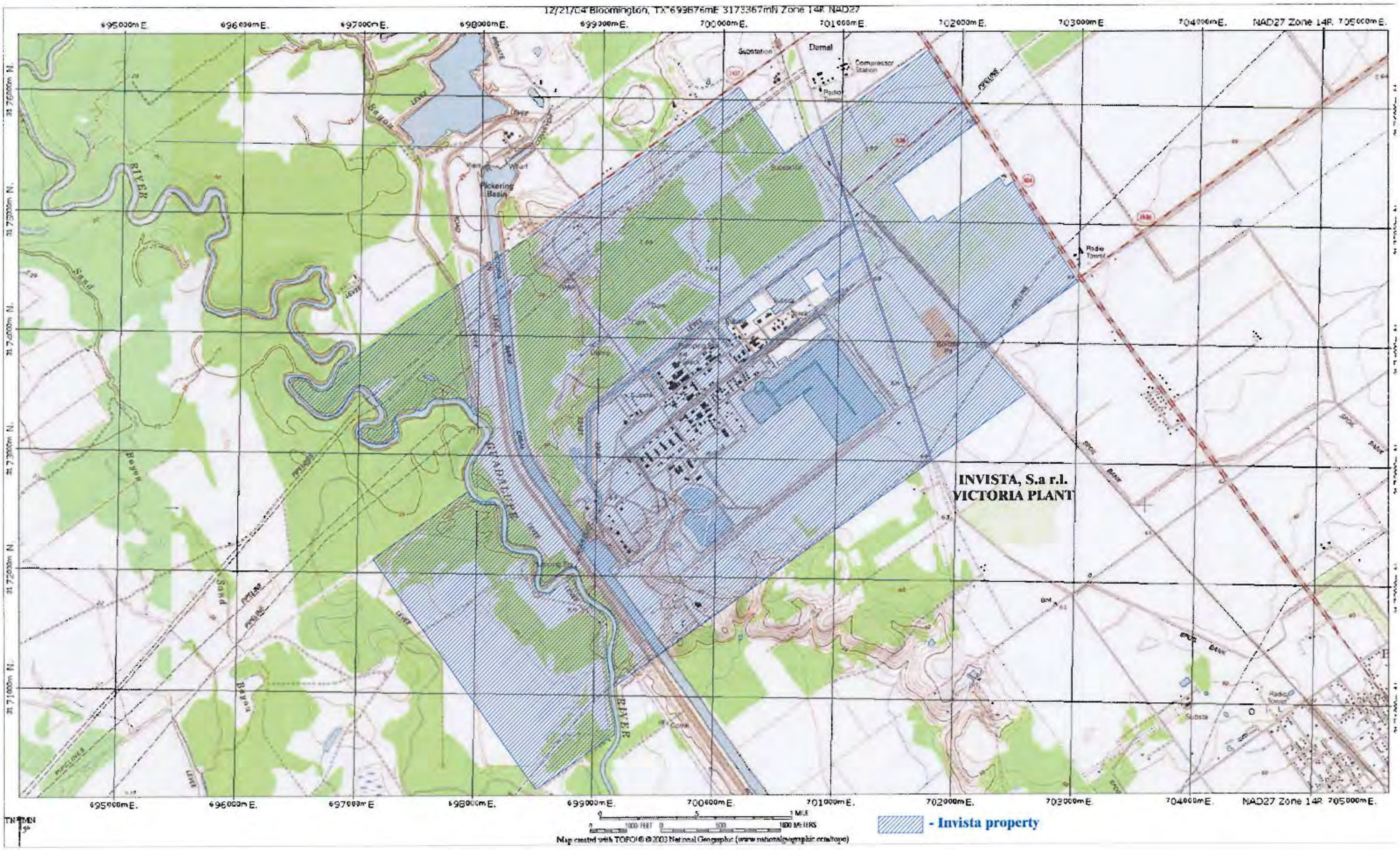
PROPOSED WEST POWERHOUSE GHG FUGITIVE EMISSIONS INCREASES

	Streams			Fuels (Low BTU)	Fuels (High BTU)	Natural Gas (Including MS Regen)
	Monitoring Program			28VHP Monitoring Where Applicable	28VHP or Annual Monitoring Where Applicable	28VHP Monitoring Where Applicable
Emission Source	SOCMI w/out C2 Factor[1] (lb/hr/ source)	28VHP Control Factor [2]	Annual 500 ppm Monitoring Control Factor [3]	Source Count	Source Count	Source Count
Valves (light liquid)	0.0035	97%	75%	34	42	6
Valves (gas stream)	0.0089	97%	75%	204	226	374
Pumps (light liquid)	0.0386	85%	75%	1	6	0
RV (gas)	0.2293	97%	75%	1	0	3
Flanges/Conn (light liquid)	0.0005	30%	75%	131	100	15
Flanges/Conn (vapor)	0.0029	30%	75%	555	530	438
Closed Vent Flange/Conn (gas)	0.0029	30%	75%	0	0	628
TOTALS				926	904	1464

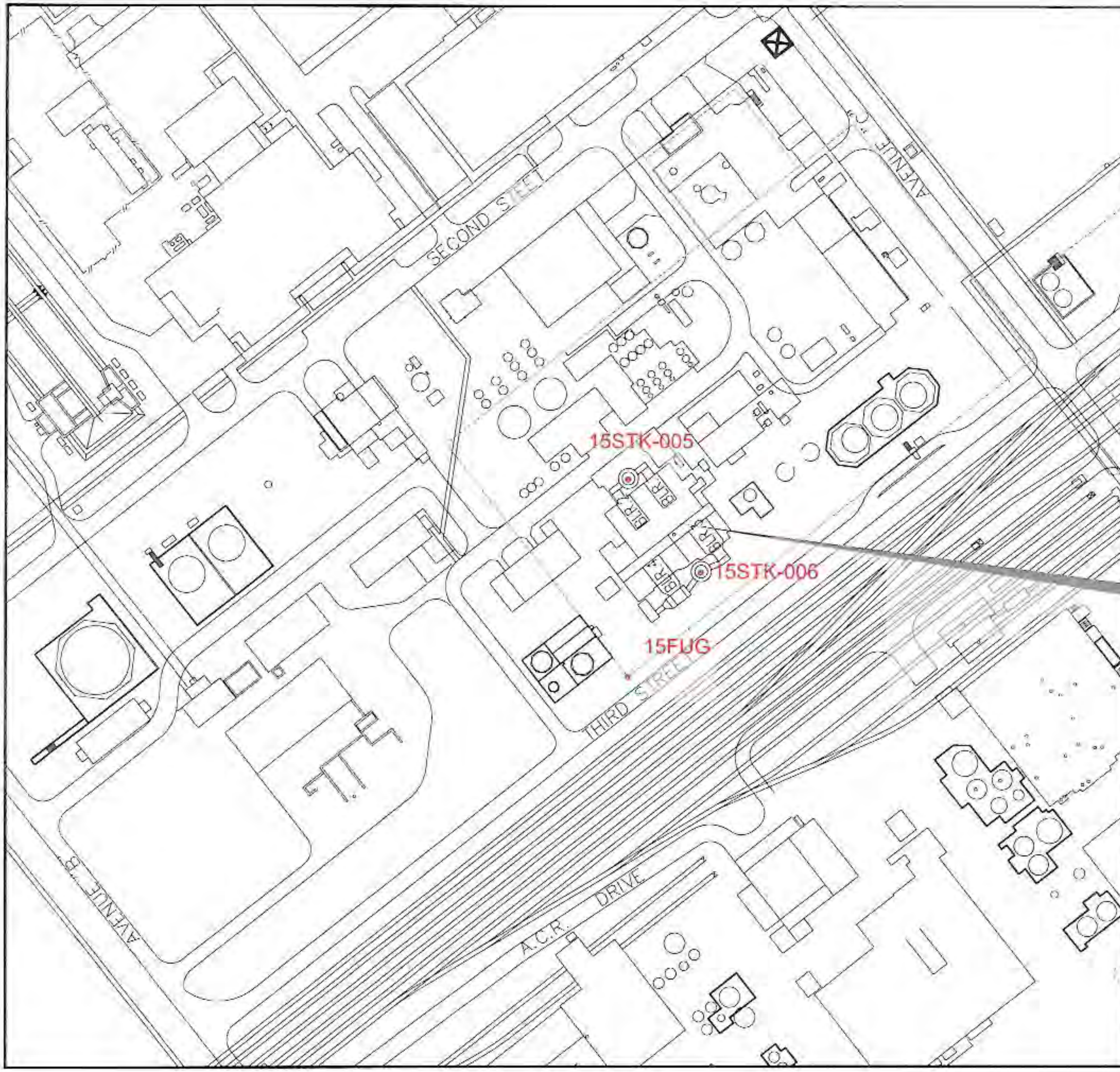
SPECIATED EMISSIONS (Average Annual):

CHEMICAL	Emissions (ton/yr)	Emissions (ton/yr)	Emissions (ton/yr)	Total (ton/yr)
N_2O	2.37	0	0	2.37
CO_2	0.410	0.766	0.481	1.66
CH_4	0.003	0.616	10.03	10.65
CO_2e				959.4

Appendix A - Area Map and Plot Plan



12/21/04 Bloomington, TX 699876mE 3173367mN Zone 14R NAD27
INVISTA, S.a r.l.
VICTORIA PLANT
- Invista property
Substation
Dernal
Compressor Station
Radio Tower
Pickering Basin
Wharf
GUADALUPE
RIVER
Sand
Bayou
LEVEE
PIPELINE
SPOIL BANK
NAD27 Zone 14R
Map created with TOPO!® ©2003 National Geographic (www.nationalgeographic.com/topo)



WEST POWERHOUSE
AREA LOCATION

Emission Point Number	Location Easting, Northing
15FUG	699718, 3173642
15STK-005	699718, 3173708
15STK-006	699742, 3173677

WAID ENVIRONMENTAL

Appendix B - Forms and Tables

- PI-1
- Table 1(a): Emission Rates

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*):		
B. Company Official Contact Name: Stephen W. Harvill		
Title: Plant Manager		
Mailing Address: PO Box 2626		
City: Victoria	State: TX	ZIP Code: 77902-2626
Telephone No.: (361) 572-1201	Fax No.: (361) 572-1515	E-mail Address: stephen.w.harvill@invista.com
C. Technical Contact Name: Peter G. Buckman		
Title: Sr. Air Permitting Engineer		
Company Name: INVISTA S.à r.l.		
Mailing Address: PO Box 2626		
City: Victoria	State: TX	ZIP Code: 77902-2626
Telephone No.: (361) 580-5954	Fax No.: (361) 580-6908	E-mail Address: peter.g.buckman@invista.com
D. Site Name: Victoria Plant		
E. Area Name/Type of Facility: Utilities/West Powerhouse		☑ Permanent ☐ Portable
F. Principal Company Product or Business: Industrial Organic Chemicals		
Principal Standard Industrial Classification Code (SIC): 2869		
Principal North American Industry Classification System (NAICS): 325199		
G. Projected Start of Construction Date: May 1, 2013		
Projected Start of Operation Date: First boiler on or before December 31, 2013; last boiler on or before December 31, 2016.		
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° 40' 41"	Longitude (nearest second): 96° 57' 17"	

Table 1(a) Emission Point Summary

Date: March 2012	**Permit No.:** To be assigned	**Regulated Entity No.:**	**RN102663671**
Area Name: **West Powerhouse**		**Customer Reference No.:**	**CN602582231**

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

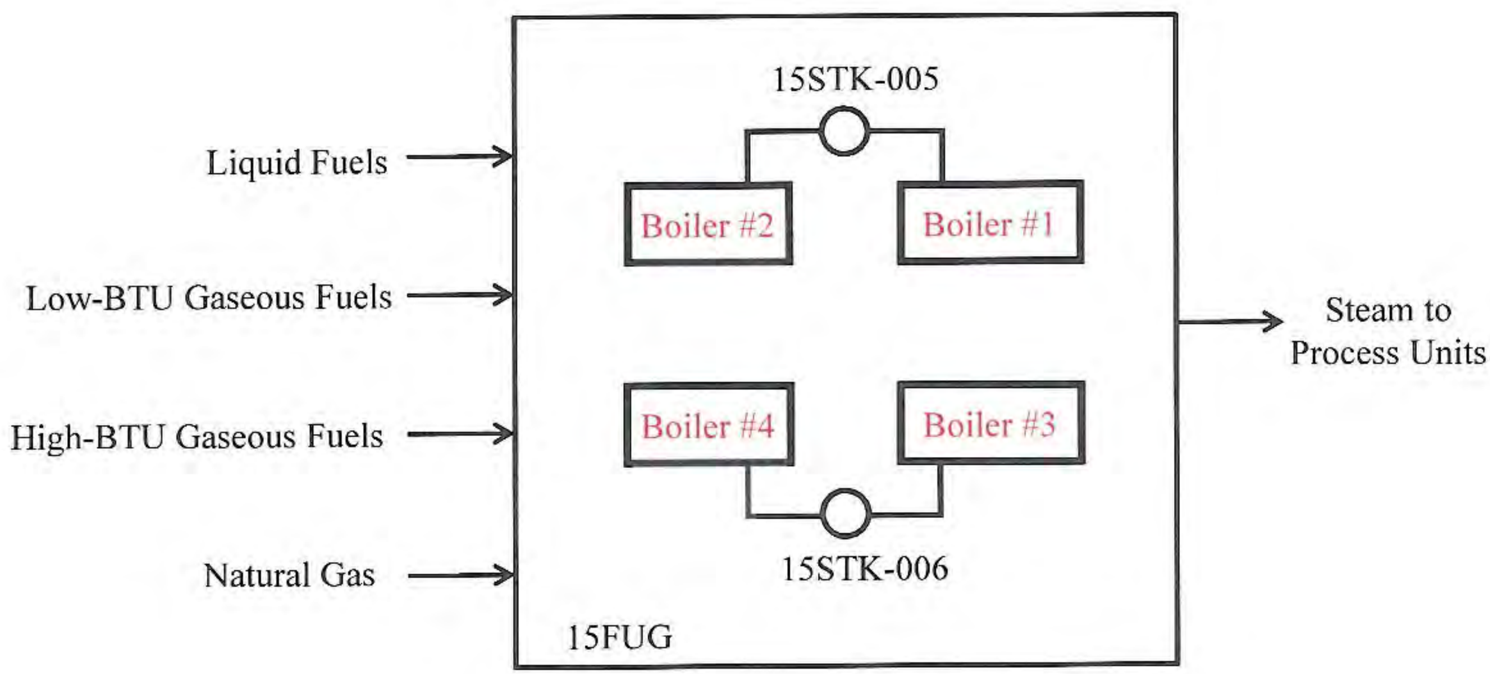
AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		Metric Tons of CO_2e per Year	TPY
15STK-005 15STK-006	15BLR001 15BLR002 15BLR003 15BLR004	Boiler No. 1 Boiler No. 2 Boiler No. 3 Boiler No. 4	CO_2	1,152,799	1,270,730
			CH_4	209	11
			N_2O	91,376	325
			CO_2e	1,244,384	1,371,684
15FUG	15FUG	Fugitives	CO_2	3.92	4.33
			CH_4	596.4	31.31
			N_2O	2915.5	10.37
			CO_2e	3,515.9	3,875.5

EPN = Emission Point Number

FIN = Facility Identification Number

Appendix C – General Process Flow Diagram

Victoria West Power Boilers Area Diagram



Appendix D – Best Available Control Technology (BACT) Reference Information

- Approximate Costs of Carbon Capture and Transport Systems
- TCEQ 28VHP Leak Detection and Monitoring Program
- U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) Search Results

Approximate Annual Costs of Carbon Capture, Transport, and Storage [1]

Parameter	Value
Approximate CO_2 Production (tons)	1,371,684
Estimated CO_2 Capture Efficiency [2]	90%
Annual CO_2 Captured (tons)	1,234,516
Minimum Length of Pipeline (km) [3]	161

Parameter	Approximate Cost Factors	Approximate Annual Cost ($)
Post-Combustion CO_2 Capture and Compression		
Minimum Cost	$ 44.45 / ton CO_2 captured[4]	$54,877,315
Maximum Cost	$ 86.18 / ton CO_2 captured[4]	$106,394,795
Average Cost	$ 65.32 / ton CO_2 captured[4]	$80,636,055
CO_2 Transport		
Minimum Cost	$ 0.91 / ton CO_2 transported per 100 km[3]	$1,803,112
Maximum Cost	$ 2.72 / ton CO_2 transported per 100 km[3]	$5,409,335
Average Cost	$ 1.81 / ton CO_2 transported per 100 km[6]	$3,606,224
CO_2 Storage (including monitoring)		
Minimum Cost	$ 0.51 / ton CO_2 stored[4,5]	$627,169
Maximum Cost	$ 18.14 / ton CO_2 stored[4,5]	$22,398,904
Average Cost	$ 9.33 / ton CO_2 stored[6]	$11,513,037
Total Cost for Capture, Compression, Transport, and Storage Combined		
Minimum Cost	$ 46.42 / ton CO_2 captured and stored	$57,307,596
Maximum Cost	$ 108.71 / ton CO_2 captured and stored	$134,203,034
Average Cost	$ 77.57 / ton CO_2 captured and stored[6]	$95,755,315

[1] This table is based on a similar table in the LCRA Statement of Basis Document found on the EPA Region 6 Internet site http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/lcra_sob.pdf and has revised with site-specific changes.

[2] Capture efficiency value as per LCRA GHG PSD Permit Application Statement of Basis document p 17.

[3] The length of the pipeline needed was based on the distance to the closest active CO_2 pipeline based on the Texas Railroad Commission's pipeline database (http://gis2.rrc.state.tx.us/public/startit.htm).

[4] These cost factors are from *Report of the Interagency Task Force on Carbon Capture and Storage*, pp. 34, 37, and 44 (Aug 2010) (http://www.epa.gov/climatechange/policy/ccs_task_force.html). The factors from the report in the form of $/tonne of CO2 emissions avoided, transported, or stored and have been converted to $/ton. Per the report, the factors are based on the increased cost of electricity (COE; in $/kW-h) of an energy-generating system, including all the costs over its lifetime.

[5] "Cost estimates [for geologic storage of CO_2] are limited to capital and operational costs, and do not included potential" costs associated with long-term liability (from the *Report of the Interagency Task Force on Carbon Capture and Storage*, p. 44).

[6] The average cost factors are the arithmetic mean of the minimum and maximum factors for each CCS component system and for the total of all systems combined.

Estimated Capital Costs for Carbon Capture and Storage (CCS)

Estimated CCS capital costs include the following primary items:

1. CO_2 capture
2. Pipeline

1. CO_2 capture capital cost estimate

Reference: Aboudheir, A. and G. McIntyre, "Industrial Design and Optimization of CO2 Capture, Dehydration, and Compression Facilities."

Table IV in the reference provides capital costs for a coal power plant and for a NCGG power plant, each of which produces 3307 ton/day of CO2. The capital cost of the CO2 capture system for the WPH boilers is estimated based on multiplying the costs from the reference by the ratio of CO2 production rates raised to the 0.6 power.

Basis:	CO2 production capacity in reference:	3307	ton/day
	Capital Cost for CO2 capture from a coal power plant:	$165	million
	Capital Cost for CO2 capture from a NGCC power plant:	$227	million
	INVISTA WPH boiler estimated CO2 daily maximum production capacity:	5287	ton/day

Capital costs are scaled based on the ratio of CO2 daily average production rates to the 0.6 power:

Minimum estimate = ($165 million) (5286.756 / 3307)^0.6 =	$219	million.
Maximum estimate = ($227 million) (5286.756 / 3307)^0.6 =	$301	million.

2. Pipeline capital cost estimate

Reference: U.S. Department of Energy National Energy Technology Laboratory, "Estimating Carbon Dioxide Transport and Storage Costs," March 2010.

Basis:	INVISTA WPH boiler CO2 daily maximum production capacity:	5287 ton/day
	Pipeline minimum length (L):	100 miles
	Pipeline diameter (D), based on Figure 4 in the reference =	10 inches
	Materials cost = \$64,632 + \$1.85 x L x (330.5 x D^2 + 686.7 x D + 26960) =	$12.4 million
	Labor cost = \$341,627 + \$1.85 x L x (343.2 x D^2 + 2074 x D + 170,013) =	$42.0 million
	Miscellaneous = $150,166 + $1.58 x L x (8,417 x D + 7,234) =	$14.6 million
	Right of Way = $48,037 + $1.20 x L x (577 x D + 29788) =	$4.3 million
	CO2 Surge Tank =	$1.2 million
	Pipeline Control System =	$0.1 million
	Total	$74.6 million

Estimated Minimum Grand Total for CCS =	$293 million
Estimated Maximum Grand Total for CCS =	$375 million

TCEQ 28VHP Leak Detection and Monitoring Program

A. These conditions shall not apply where the (1) VOC has an aggregate partial pressure or vapor pressure of less than 0.044 pound per square inch, absolute (psia) at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made readily available upon request.

The exempted components may be identified by one or more of the following methods:

(1) piping and instrumentation diagram (PID);

(2) a written or electronic database;

(3) color coding;

(4) a form of weatherproof identification; or

(5) designation of exempted process unit boundaries.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked buried connectors shall be welded.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), shall be identified in a list to be made readily available upon request. The difficult-to-monitor and unsafe-to-monitor valves may be identified by one or more of the methods described in Subparagraph A above. If an unsafe-to-monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times. A difficult-to-monitor component for which quarterly monitoring is specified may instead be monitored annually.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the removal of a component or equipment for repair or replacement results in an open ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

(1) a cap, blind flange, plug, or second valve must be installed on the line or valve; or

(2) the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once at the end of the 72 hour period following the creation of the open ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings 500 ppmv above background and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

A check of the reading of the pressure-sensing device to verify disc integrity shall be performed weekly and recorded in the unit log or equivalent. Pressure-sensing devices that are continuously monitored with alarms are exempt from recordkeeping requirements specified in this paragraph.

The gas analyzer shall conform to requirements listed in Method 21 of 40 CFR Part 60, Appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the process fluid. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured.

Replacements for leaking components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 parts per million by volume (ppmv) or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor, and agitator seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days. Records of the first attempt to repair shall be maintained.

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC § 115.782(c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown as calculated in accordance with 30 TAC § 115.782 (c)(1)(B)(i)(I), the TCEQ Regional Manager and any local programs shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

J. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings Records of physical inspections shall be noted in the operator s log or equivalent.

K. Alternative monitoring frequency schedules of 30 TAC §§ 115.352 - 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable NESHAPS and does not constitute approval of alternative standards for these regulations.

EPA RACT/BACT/LAER CLEARINGHOUSE (RBLC) QUERY RESULTS

RBLCID	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	POLLUTANT	CONTROL METHOD CODE	CONTROL_METHOD_DESCRIPTION
AL-0231	06/12/2007 ACT	VACUUM DEGASSER BOILER	NATURAL GAS	Carbon Dioxide	N	
LA-0148	05/28/2008 ACT	MULTIPLE HEARTH FURNACES / AFTERBURNERS	COAL	Carbon Dioxide	A	Afterburner and good combustion practices
*LA-0248	01/27/2011 ACT	DRI-108 - DRI Unit #1 Reformer Main Flue Stack	Iron Ore and Natural Gas	Carbon Dioxide	B	the best available technology for controlling CO2e emissions from the DRI Reformer is good combustion practices, the Acid gas separation system, and Energy integration. BACT shall be good combustion practices, which will be adhered to maintain low levels of fuel consumption by the LNB burners.
*LA-0248	01/27/2011 ACT	DRI-208 - DRI Unit #2 Reformer Main Flue Stack	Iron ore and Natural Gas	Carbon Dioxide	B	the best available technology for controlling CO2e emissions from the DRI Reformer is good combustion practices, the Acid gas separation system, and Energy integration. BACT shall be good combustion practices, which will be adhered to maintain low levels of fuel consumption by the LNB burners.
*LA-0254	08/16/2011 ACT	AUXILIARY BOILER (AUX-1)	NATURAL GAS	Methane	P	Proper operation and good combustion practices
*LA-0254	08/16/2011 ACT	AUXILIARY BOILER (AUX-1)	NATURAL GAS	Nitrous Oxide (N2O)	P	Proper operation and good combustion practices
*LA-0254	08/16/2011 ACT	AUXILIARY BOILER (AUX-1)	NATURAL GAS	Carbon Dioxide	P	Proper operation and good combustion practices
*LA-0254	08/16/2011 ACT	EMERGENCY DIESEL GENERATOR	DIESEL	Methane	P	Proper operation and good combustion practices
*LA-0254	08/16/2011 ACT	EMERGENCY DIESEL GENERATOR	DIESEL	Nitrous Oxide (N2O)	P	Proper operation and good combustion practices
*LA-0254	08/16/2011 ACT	EMERGENCY DIESEL GENERATOR	DIESEL	Carbon Dioxide	P	Proper operation and good combustion practices
*LA-0254	08/16/2011 ACT	EMERGENCY FIRE PUMP	DIESEL	Methane	P	Proper operation and good combustion practices
*LA-0254	08/16/2011 ACT	EMERGENCY FIRE PUMP	DIESEL	Nitrous Oxide (N2O)	P	Proper operation and good combustion practices
*LA-0254	08/16/2011 ACT	EMERGENCY FIRE PUMP	DIESEL	Carbon Dioxide	P	Proper operation and good combustion practices
OK-0135	02/23/2009 ACT	CARBON DIOXIDE VENT		Carbon Dioxide	N	Good operation practices.
TX-0347	10/16/2001 ACT	REGENERATION HEATER, DDB-201		Carbon Dioxide	N	None Indicated
TX-0347	10/16/2001 ACT	DECOKE STACK, DDF-101		Carbon Dioxide	N	None Indicated
TX-0481	11/02/2004 ACT	EMERGENCY GENERATOR		Carbon Dioxide	N	
TX-0550	02/10/2010 ACT	N-11, REACTOR REGENERATION EFFLUENT	METHANE	Carbon Dioxide	N	
TX-0550	02/10/2010 ACT	N-18, DECOKING DRUM	METHANE	Carbon Dioxide	N	
TX-0550	02/10/2010 ACT	N-10, CATALYST REGENERATION EFFLUENT	METHANE	Carbon Dioxide	N	

Control method*: The method was used to achieve the emission limits. The choices which may be entered are:

P – Pollution prevention techniques, e.g., any required process modification, change in raw material, or management practice designed to decrease or prevent pollutant emissions;

A – Add-on control equipment;

B – Both pollution prevention and add-on equipment; and

N – No feasible controls.