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Bishop, TX 78343
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Bishop, TX 78343-0428/

Telephone: (361) 443-8238

Celanese

August 29, 2014

Mike Wilson
Air Permits Director
Texas Commission on Environmental Quality (TCEQ) - MC163
12100 Park 35 Circle
Austin, Texas 78753

Wren Stenger
Multimedia Planning and Permitting
Environmental Protection Agency
Region VI,
1445 Ross Avenue
Dallas, TX 75202

Re: Boiler Project Greenhouse Gas PSD Initial Permit Application
Ticona Polymers, Inc – Bishop Plant
TCEQ RN: 101625721, TCEQ CN: 600124184

Dear Ms. Stenger and Mr. Wilson;

Ticona Polymers, Inc. (Ticona) is planning to construct and operate three new boilers at its plant located in Bishop, Texas. Ticona is submitting the enclosed application to address the Best Available Control Technology requirements for Greenhouse Gases (GHG) that will be emitted from the proposed boilers. The Boiler project is also a major source for several criteria pollutants. The authorization for non-GHG criteria pollutants has been submitted under a separate cover to the TCEQ.

The EPA is currently in the process of delegating permitting authority to the TCEQ. Ticona respectfully requests that, should the delegation be completed prior to public notice, subsequent review of our application be transferred to the TCEQ, so that the TCEQ would be the permit issuing authority for the GHG permit. To expedite this, we are submitting this application to both EPA and the TCEQ. We understand that you will coordinate permit review to avoid double work, and we will work with either or both agencies, as you may request.

If you have any questions or need additional information, please contact Bill Chidester at 361-584-6614 or William.Chidester@celanese.com. Thank you for your time and consideration regarding this matter.

Sincerely,

David W. Townsend

David Townsend
Engineering Fellow

Attachments

cc: Jeffrey Robinson, USEPA

RECEIVED
14 SEP -3 PM 4: 06
AIR PERMITS SECTION
6PD-R

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ENVIRONMENTAL CONSULTING

Greenhouse Gas Prevention of Significant Deterioration Permit Application for New Boilers

Ticona Polymers, Inc.
Bishop Facility

August 2014

715 DISCOVERY BLVD., SUITE 301 • CEDAR PARK, TEXAS • 78613 • 512/258-8500 • FAX 512/258-7522

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SECTION 1
INTRODUCTION

1.1 Introduction

Ticona Polymers, Inc. (Ticona) is hereby requesting a Prevention of Significant Deterioration (PSD) permit for greenhouse gases (GHG) that will be emitted from three new boilers to be located at its Bishop Facility in Bishop, Texas. The boilers will provide steam to existing steam users at the Bishop Facility as well as a new methanol production unit proposed in a separate application.

1.2 Background

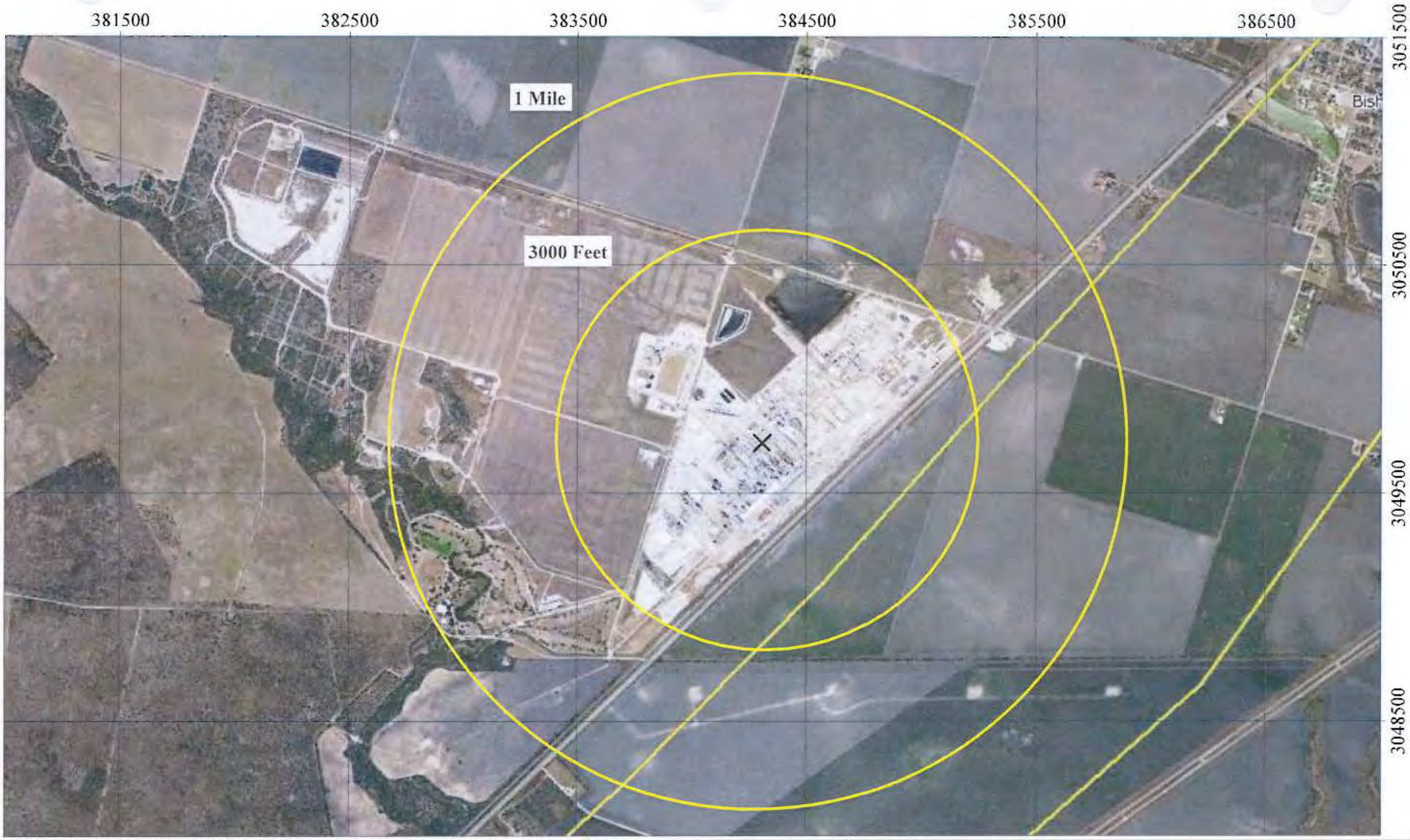
Ticona owns and operates multiple manufacturing units at the Bishop Facility located at 5738 County Road 4, Bishop, Nueces County, Texas. An Area Map, Figure 1-1, of the Bishop Facility and surrounding area has been included at the end of this section. The Bishop Facility includes numerous chemical production units. A new methanol production unit is proposed in a separate application. Steam demand from the new methanol unit, a new air separation unit, and existing facilities, will be supplied by the new boilers proposed in this application.

The Ticona Bishop Facility is an existing major source under the federal PSD program. Therefore, physical changes and changes in the method of operation are potentially subject to PSD permitting requirements. The project to construct new boilers and the project to construct a new methanol unit will be evaluated as a single PSD project. However, two separate applications are being submitted for two GHG PSD permits to facilitate potential transfer of ownership of some of the equipment in the future. A PSD review is required because GHGs are expected to increase by more than 75,000 tons per year (tpy) expressed as CO_2 equivalent (CO_2e) and emissions of at least one of non-GHG PSD criteria pollutants are expected to increase above its respective PSD threshold. The PSD application for non-GHG pollutants will be submitted in a separate application to the Texas Commission on Environmental Quality (TCEQ).

This GHG permit application has been prepared based upon Environmental Protection Agency's guidance, including the "New Source Review Workshop Manual," the March 2011 document, "PSD and Title V Permitting Guidance for Greenhouse Gases (EPA-457/B-11-001) and the memo dated October 15, 2012, "Timely Processing of Prevention of Significant Deterioration Permits When EPA or PSD-Delegated Air Agency Issues the Permit."

1.3 Project Scope

The proposed project will emit GHG emissions, and thus Ticona is applying for a GHG PSD permit covering the following activities:



SCALE (meters)

0 500 1000 1500 2000

UTM Zone 14

NORTH

FIGURE 1-1
SITE LOCATION ON Aerial Photo from Google Earth
TICONA POLYMERS, Inc.
BISHOP PLANT

SAGE
ENVIRONMENTAL CONSULTING
"Friendly Service, No Surprises!"

DATE: August 2014

PROJECT: 400-61-8-4-2-1

FILE NAME: Aerial Photo.srf

SECTION 2
PROPOSED PROJECT DESCRIPTION

This project proposes to construct and operate three new gas-fired package boilers. Each will use either pipeline-quality natural gas or a mixture fuel with process gas, as fuel to a design firing capacity of 452 MMBtu/hour. These boilers will provide steam for various processes at the Bishop Facility, including a new Methanol Unit. Each boiler may operate on hot standby or minimal rates depending upon facility steam demand.

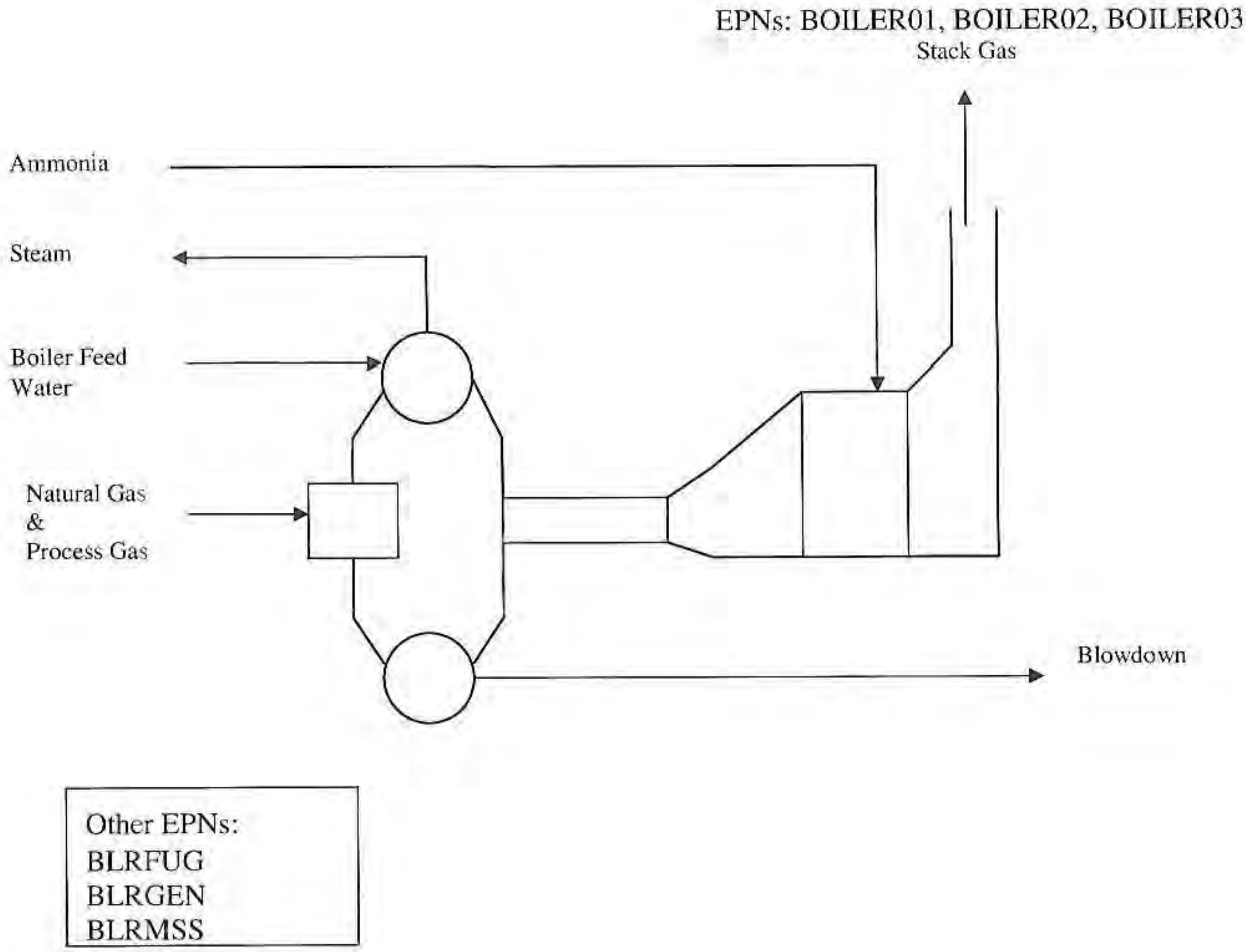
The fuel will consist of pipeline quality natural gas as well as process gases generated at the Bishop Facility. The use of process gas reduces natural gas usage at the facility as well as provides highly efficient control of VOC in the process vents.

Selective Catalytic Reduction (SCR) will be used as a post-combustion control method of NOx emission reduction when required. SCR involves injecting ammonia into the flue gas in the presence of a catalyst to convert NOx to nitrogen and water. Anhydrous ammonia will be utilized for the SCR system, which will be stored nearby in a pressure vessel that will have no emission to atmosphere during normal operations. The injected ammonia that is not consumed in the SCR reaction will be emitted to the atmosphere as ammonia "slip."

Sources of GHG emissions from the process include carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) from the boilers (EPNS: BOILER1, BOILER2, BOILER3), CH_4 fugitive emissions from piping connections (EPN: BLRFUG) and CH_4 from various MSS events required to assure proper operation of the boilers and associated equipment (EPN: BLRMSS). A diesel fueled emergency generator and associated diesel storage (EPN: BLRGEN) will be installed and used to provide back-up to power when needed.

A simplified process flow diagram is provided in Figure 2-1 at the end of this section.

Figure 2-1: Simplified Process Flow Diagram (PFD)
Ticona Polymers
Bishop Plant
New Boilers



SECTION 3
EMISSIONS ESTIMATE METHODOLOGY

Projected emissions of the CO_2, CH_4, and N_2O were calculated for the boilers, fugitive equipment in CH_4 service, and maintenance activities. CO_2, CH_4, and N_2O have a global warming potential (GWP) of 1, 25, and 298, respectively, which are used to determine the total CO_2e emissions.

3.1 Boilers (EPNs: BOILER01, BOILER02, BOILER03)

The burners in the firebox of each boiler combust a mixture of ambient air and gaseous fuel, resulting in GHG products of combustion. Gaseous fuel will be provided by either pipeline-quality sweet natural gas or natural gas combined with process gas from existing processes.

Process Gas Contribution:

The combustion of the process gas produces CO_2, CH_4, and N_2O. CO_2 is created by the stoichiometric conversion of the carbon containing compounds in the process gas stream. Complete conversion of the carbon components of the purge gas fuel to CO_2 is used to calculate the worst case emissions via the Tier 3 equation in the EPA GHG Mandatory Reporting Rule, 40 CFR Part 98, Subchapter C. N_2O and CH_4 emissions from the combustion of the process gas were calculated from the fuel gas factors in 40 CFR Part 98, Subchapter C, Table C-2.

Natural Gas Contribution:

CO_2 resulting from the combustion of natural gas was calculated using the maximum firing rate and the factor from the EPA GHG Mandatory Reporting Rule, 40 CFR Part 98, Subchapter C, Table C-1. N_2O and CH_4 emissions from the combustion of the natural gas fuel were calculated using the maximum firing rates and the natural gas factors from the EPA GHG Mandatory Reporting Rule, 40 CFR Part 98, Subchapter C, Table C-2.

3.2 Fugitive Equipment (EPN: BLRFUG)

Fugitive GHG emissions from the boiler fugitive components in CH_4 service were estimated in accordance with the TCEQ Technical Guidance Package for Equipment Leak Fugitives, October 2000. Emissions were estimated using the SOCMI AP-42 emission factors for SOCMI processes without Ethylene and estimated stream compositions. Reduction credits were taken for the TCEQ 28VHP leak detection and repair program for streams with greater than 10% CH_4 by weight.

3.3 Emergency Engine (EPN: BLRGEN)

Emissions from the emergency generator were estimated in accordance with the EPA GHG Mandatory Reporting Rule. Per 40 CFR Part 63 Subpart ZZZZ, emergency engines are only allowed to run up to 100 hours per year in non-emergency situations. GHG emissions were calculated based on the worst case annual heat input for 100 hours of non-emergency use per year.

3.4 MSS Activities of Methane Containing Equipment (EPN: BLRMSS)

The GHG Emissions from MSS activities were calculated based on a representative maximum volume vented when isolating sections of pipe or equipment for the purposes of maintenance, start-up or shutdown.

SECTION 4
GHG BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

GHG emissions from the new boilers will be greater than 75,000 tpy expressed as CO_2e, subject to PSD review; therefore, a Best Available Control Technology (BACT) analysis must be conducted for GHG pollutants and applicable emission sources. The following sources are subject to BACT review:

- Boilers (EPNs: BOILER01, BOILER02, BOILER03)
- Fugitive Emissions (EPN: BLRFUG)
- Emergency Generator (EPN: BLFGEN)

The new boilers will be designed with many inherent energy efficiency features. The following evaluation focuses on how the design incorporates elements that minimize the formation of GHG pollutants.

4.1 BACT Analysis Methodology

BACT for GHG emissions from the project has been evaluated via a "top-down" approach that includes the steps outlined in the following subsections.

U.S. EPA has issued limited guidance documents related to the completion of GHG BACT analyses. The following guidance documents were utilized as resources in completing the GHG BACT evaluation for the proposed project:

- PSD and Title V Permitting Guidance For Greenhouse Gases (hereafter referred to as General GHG Permitting Guidance); and
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boiler (hereafter referred to as GHG BACT Guidance for Boilers).

4.2 BACT Top-Down Approach

4.2.1 Step 1 – Identify Control Technology

Available control technologies with the practical potential for application to the emission units and regulated air pollutants in question were identified. Available control options include the application of alternate production processes and control methods, systems, and techniques including fuel cleaning and innovative fuel combustion, when applicable and consistent with the proposed project. The application of demonstrated control technologies in other similar source categories to the emission unit can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts; control technologies with potential application to the emission unit under review are identified 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 Rate (LAER) Clearinghouse (RBLC) database;
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 or trade organizations.

In addition, Ticona utilized the following additional resource:

- *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers*

Ticona completed a search of the RBLC and GHG Mitigation Strategies Databases with the following results:

- RBLC database – The database is a more mature list of options for the control traditional criteria pollutants such nitrogen dioxide and carbon monoxide than it is for GHG. However, there are some entries under the 11.310 Fuel Combustion Process Code that include CO_2e worth noting for the purposes for this GHG BACT analysis. Best Operational Practices ("Proper operation," RBLC ID IA-0106), Selection of Lowest Carbon Fuel ("use of natural gas," RBLC ID IA-0106, "use of natural gas or sng," RBLC ID IN-0166), and Installation of Energy Efficiency Options ("improved combustion measures," RBLC ID LA-0266, "energy efficiency boiler design" RBLC ID IN-0166) consistent with the options discussed in this analysis are found in the RBLC.

- GHG Mitigation Strategies Database - The GHG Mitigation Strategies Database did not contain any information for emission sources presented in this analysis.

4.2.2 Step 2 – Eliminate Technically Infeasible Options

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling the PSD pollutant emissions above threshold limits from the source. The first question in determining whether or not a technology is feasible, is whether it is a "demonstrated" technology. Demonstrated means that it has been installed and operated successfully elsewhere on a similar facility. 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.

An undemonstrated technology is only technically feasible if it is "available" and "applicable". A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available". Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emission streams from similar sources successfully implementing the control alternative. The 1990 New Source Review Workshop Manual explains the concept of applicability as follows: "An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration." Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the 1990 New Source Review Workshop Manual.

4.2.3 Step 3 – Rank Remaining Control Technologies

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

4.2.4 Step 4 – Evaluate the 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 identified.

According to 40 CFR §52.21 (b)(49)(ii), CO_2e emissions must be calculated by scaling the mass of each of the six GHGs by the gas's associated GWP, which is established in Table A-1 of Subpart A of 40 CFR Part 98. Therefore, to determine the most appropriate strategy for prioritizing the control of CO_2 and CH_4 emissions, Ticona considered each component's relative GWP. As shown in Table 4-1, the GWP of CH_4 is 25 times the GWP of CO_2. Therefore, one ton of atmospheric CH_4 emissions equates to 25 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 approximately 2.7 tons of CO_2e emissions. Since the combustion of CH_4 decreases GHG emissions by approximately 89 percent on a CO_2e basis, combustion of CH_4 is preferential to direct emission of CH_4.

Table 4-1 Global Warming Potentials

Pollutant	GWP
CO_2	1
CH_4	25
N_2O	298

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 relatively higher CO emissions.

4.2.5 Step 5 – Selection of BACT

In the final step, BACT 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 reductions achievable with the selected control technology.

4.3 GHG BACT Evaluation for Boilers

The following section presents BACT evaluations for GHG emissions generated from the new boilers.

4.3.1 Step 1 – Identification of Potential GHG Control Technologies

The following potential GHG control strategies for the boilers were considered as part of this BACT analysis:

- Selection of the Lowest Carbon Fuel;
- Installation of Energy Efficiency Options;
- Best Operational Practices; and
- Carbon Capture and Storage (CCS).

4.3.1.1 *Section of the Lowest Carbon Fuel*

For GHG BACT analyses, low-carbon fuel or non-carbon based fuels are the primary control option that can be considered for a lower emitting process as low-carbon fuels have less carbon that will be converted to CO_2. The boilers will combust natural gas as the primary fuel and may combust process gas from existing process units as low carbon fuels when practicable and available. Natural gas is the lowest emitting GHG fuel on a direct carbon basis compared to other typical purchased fossil fuels.

Hydrogen rich process gas would have a lower carbon content than natural gas. A methanol process unit proposed under a separate permit application will produce some hydrogen rich process gas; however, the stream will be used to reduce GHG emissions from the reformer and will therefore not be available to the boilers.

In summary the available fuel options are:

- High carbon content fuels;
- Natural gas; and
- Process gas.

4.3.1.2 *Installation of Energy Efficiency Options*

This section describes the energy efficiencies that will be incorporated into the design of Ticona's boilers to reduce GHG emissions.

Boiler feed water for the boilers will be heated in a deaerator with low pressure steam and will be further heated by recovering waste heat from hot flue gas in an economizer.

Process gas will be captured and utilized as fuel in the boilers. This allows the process to be more energy efficient by reducing the amount of natural gas fuel usage.

Ticona will utilize efficient low-NO_x design burners to reduce emissions from non-GHG pollutants. The burners will be designed to accomplish good mixing of air and fuel for proper combustion and minimize excess oxygen.

The firebox will be designed to maximize thermal efficiency. The walls of the firebox will be insulated with appropriate insulation material to reduce heat loss.

4.3.1.3 *Best Operational Practices*

Ticona will maintain a thermal efficiency of at least 77% on a 12-month rolling basis. Ticona will also monitor stack excess O_2 to ensure efficient combustion. The fuel requirements increase as the facility operates with more excess air. Maintenance activities will be implemented to ensure the boilers are kept in good working condition. These activities range from instrument calibration to cleaning of dirty or fouled mechanical parts. With respect to GHG emissions potential, these activities maintain performance as opposed to enhancing performance. Performing proper maintenance on the system will increase thermal efficiency on average by 10% as identified in the Energy Star document *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry.*

4.3.1.4 *Carbon Capture and Storage*

Carbon Capture and Storage (CCS) involves separation and capture of CO_2 emissions from the flue gas, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and/or injection and long-term geologic storage of the captured CO_2. Several different technologies have demonstrated the potential to separate and capture CO_2. To date, some of these technologies have been demonstrated at the laboratory scale only, while others have been proven effective at the slip-stream or pilot-scale. Numerous projects are currently planned for the full-scale demonstration of CCS technologies.

According to U.S. EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA-457/B-11-001):

> For the purposes of a BACT analysis for GHG, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).

The boilers proposed in this application will not produce the same amount of CO_2 as a fossil fuel-fired power plant that is used to directly serve the energy grid, nor will CO_2 purity of the exhaust stream be comparable to the types of production listed in this guidance. Therefore, CCS is not considered by this guidance to be an "available" add-on control technology for this flue gases from the boilers. However, this discussion treats the technology as "available" for completeness. Currently there are two options for CO_2 capture for high purity CO_2 streams: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes.

Capture or separation of the CO_2 stream alone is not a sufficient control technology, but instead requires the additional step of permanent storage. After separation, storage could involve sequestering the CO_2 through various means such as enhanced oil recovery (EOR), saline aquifers, or sequestration in un-minable coal seams.

There are additional methods of sequestration such as potential direct ocean injection of CO_2 and algae capture and sequestration (and subsequent conversion to fuel). However, these methods are not as widely documented in the literature for industrial scale applications. As such, while capture-only technologies may be technologically available at a small-scale, the limiting factor is the availability of a mechanism (pipeline or geologic formation) to permanently sequester, store, or inject the captured gas. As discussed below, the Ticona Bishop Facility is not located near a permanent CO_2 sequester option; therefore, EOR, Saline Aquifers, or un-minable coal seams are not a technically feasible option.

The Bishop Facility is located approximately 200 miles from a conceivable recipient of recovered CO_2 gases, the Denbury Green Pipeline. However, the distance from the pipeline, the excessive site-specific cost of designing, constructing, and operating the pipeline to transport compressed CO_2 to the Denbury Green Pipeline as documented in this application and lack of similar demonstrated projects make this sequestration option infeasible for this project.

In addition to the U.S. EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases*, white papers for GHG reduction options were reviewed for discussion of CCS technologies. In the GHG BACT Guidance for Boilers white paper, a brief overview of the CCS process is provided and the guidance cites the Interagency Task Force on Carbon Capture and Storage for the current development status of CCS technologies. In the Interagency Task Force report on CCS technologies, a number of pre- and post-combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects). Capture-only technologies are technically available; however, not commercially demonstrated. In addition, the limiting factors in CCS projects are typically the lack of a geologic formation or pipeline for the carbon to be permanently sequestered or the extremely high cost of the design, construction, and operation of a CCS project.

Beyond Power Plant CCS demonstration projects, the Interagency Task Force (ITF) Report also discusses three relevant industrial CCS projects that are being pursued under the Industrial Carbon Capture and Storage (ICCS) program for the following companies/installations:

- Leucadia Energy: a methanol plant in Louisiana where 4 million tonnes per year of CO_2 will be captured and used in an enhanced oil recovery (EOR) application;
- Archer Daniels Midland (AMD): an ethanol plant in Illinois where 900,000 tonnes per year of CO_2 will be captured and stored in a saline formation directly below the plant site; and
- Air Products: a hydrogen-production facility in Texas where 900,000 tonnes per year of CO_2 will be captured and used in an EOR application.

These industrial deployments are not yet demonstrated and are capturing CO_2 streams that are drastically different from the Ticona Boiler project. The ICCS projects are capturing CO_2 from process streams with either a high concentration of CO_2 or process streams at high pressure with a high partial pressure of CO_2. Ticona's boiler flue gas has a relatively low concentration of CO_2 compared to fermentation process gas of the ADM plan). Ticona's boiler flue gas also has a low partial pressure of CO_2 compared to the Air Products and Leucadia processes. In addition, the Department of Energy is providing significant financial assistance for these projects to offset the cost and make these projects economically feasible.

The August 2010 Federal Interagency Task Force for Carbon Capture and Storage (CCS) report noted the following four fundamental near-term and long-terms concerns of CCS as a potential control technology:

1. The existence of market failures, especially the lack of a climate policy that sets a price on carbon and encourages emission reductions;
2. The need for a legal/regulatory framework for CCS projects that facilitates project development, protects human health and the environment, and provides public confidence that CO_2 can be stored safely and securely;
3. Clarity with respect to the long-term liability for CO_2 sequestration, in particular regarding obligations for stewardship after closure and obligations to compensate parties for various types and forms of legally compensable losses or damages; and
4. Integration of public information, education, and outreach throughout the lifecycle of CCS projects in order to identify key issues, foster public understanding, and build trust between communities and project developers.

4.3.2 Step 2 – Elimination of Technically Infeasible Control Options

4.3.2.1 *Selection of the Lower Carbon Fuel*

Natural gas, the lowest carbon fuel, is a technically feasible option for CO_2 control of the boilers. In addition, process gas may be used when practicable and available, which will back out the amount of natural gas equivalent to the heat release of the process gas.

4.3.2.2 *Installation of Energy Efficiency Options*

The energy efficiency options presented in Section 4.3.1.2 such as high efficiency burner design, economizer, and firebox insulation are all technically feasible.

4.3.2.3 *Best Operational Practices*

Ticona will utilize several best operation practices as described above in Section 4.3.1.3 to minimize the potential for future GHG emissions. The best operational practices from proper equipment maintenance to operational monitoring will be utilized to ensure the boilers are able to operate efficiently. All the best operational practices described are technically feasible.

4.3.2.4 *Carbon Capture and Storage*

Capture and Compression – CO_2 capture is achieved by separating CO_2 from emission sources where it is then recovered in a concentrated stream that can be sequestered. Currently there are a few options for CO_2 capture from combustion device flue gas streams: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes. Post-combustion capture uses solvent scrubbing, typically using monoethanolamine (MEA) as the solvent, is a commercially mature technology. Solvent scrubbing has been used in the chemical industry for separation of CO_2 in process streams and is an available technology for this application. However, this technology is typically used at high pressure (with high CO_2 partial pressure) and not on very low pressure flue gas streams that have low CO_2 partial pressure. This technology has not been demonstrated to be feasible in large scale industrial boiler flue gas applications.

Post-combustion membranes technology may also be used to separate or adsorb CO_2 in an exhaust stream. It has been estimated that 80 percent of the CO_2 could be captured using this technology. The captured CO_2 would then be purified and compressed for transport. Per the National Energy Technology Laboratory (owned and operated by the US Department of Energy), the use of membranes for CO_2 capture is still in the development phase.[1] All listed R&D efforts are still in bench scale or pilot plant phase. Demonstration on an industrial scale level is not anticipated until 2018. Since the current state of this technology is primarily in the research stage, post-combustion membranes are not currently feasible.

Sequestration - Lack of Sequestration Sink (Geologic or Pipeline)

While capture-only technologies may be available and demonstrated on pilot scales, a remaining hurdle is the availability of a mechanism (pipeline or geologic formation) to permanently sequester the captured gas.

Figure 4-1 (at the end of this section) and Table 4-2 (below) demonstrate the potential CO_2 Storage facilities near the Bishop facility.

[1] http://www.netl.doe.gov/technologies/coalpower/ewr/co2/PostCombustion.html

Table 4-2 Potential CO_2 Storage/EOR Sites[2]

Source	Type	Distance	Capacity	Status
Gulf of Mexico Miocene CO_2 Site Characterization Mega Transect	Storage	113 miles	68 million tonnes	Research – not commercially viable yet.
ConocoPhillips Sweeny Polygeneration Plant	Capture	162 miles	27,400 tonnes/day	Potential – Planned
Hunton Energy Freeport Plant	Capture and Storage	177 miles	21,920 tonnes/day	Potential – In Development
NRG Energy W.A. Parish Plant	Capture and Storage	185 miles	1,096 tonnes/day	Active – Existing
CEMEX Inc. Cement CO_2 Capture Project	Capture and Storage	200 miles	N/A	Terminated
Denbury Green Pipeline	Transport (Storage)	200 miles	N/A	Active - Existing

As seen in Table 4-2, no sites with a distance of less than 200 miles from the Bishop Facility are suitable candidates for CO_2 storage/EOR. The four sites closer than the Denbury Green Pipeline are unsuitable for the following reasons:

- Gulf of Mexico Miocene CO_2 Site Characterization Mega Transect - this site is still currently in research operations. Therefore it is not currently a long term commercially viable option for permanent CO_2 storage.
- ConocoPhillips Sweeny Polygeneration Plant – ConocoPhillips Sweeny is a chemical manufacturing facility. This site is currently only capturing CO_2 and does not have storage facilities for commercial use.
- Hunton Energy Freeport Plant: site is still in the development phase and is not yet ready for commercial use.
- NRG Energy W.A. Parish Plant: site does not have the CO_2 storage capacity needed to store all of the CO_2 captured from the boilers.

As stated above, the closest existing commercial CO_2 pipeline is approximately 200 miles from the Bishop Facility. The distance from the pipeline, the excessive cost of designing, constructing, and operating the CCS project to transport compressed CO_2 to the Denbury Green Pipeline, and lack of similarly demonstrated projects should all be taken into consideration.

The aforementioned technical challenges and lack of demonstrated technology associated with capture, compression and storage of CO_2 impart substantial uncertainties to the feasibility of CCS as BACT for reducing CO_2 emissions from the boilers. However, for the purposes of providing a more thorough and site-specific determination, CCS will be considered technically feasible in this analysis.

[2] Information obtained from the National Carbon Sequestration Database and Geographic Information System (NATCARB), http://www.natcarbviewer.com

4.3.3 Step 3 – Rank of Remaining Control Technologies

The various options described above for controlling and minimizing GHG emissions may be combined. Those options that are technically feasible and mutually exclusive of one another are ranked based on their overall control effectiveness:

- Carbon Capture and Storage – may reduce CO_2 by up to 90%.
- Lowest Carbon Fuel – utilizing natural gas and process gas as fuel in the boilers may reduce CO_2e by up to 14.25 kg CO_2/MMBtu (compared to Distillate Fuel Oil) or up to 19% per MMBtu of fuel used.
- Installation of Energy Efficiency Options & Best Operation Practices - implementing these design elements and best operation practices is effective at minimizing formation of CO_2 in the boilers by at least 13%.

4.3.4 Step 4 – Evaluation of Most Stringent Controls

4.3.4.1 *Carbon Capture and Storage*

To evaluate the cost effectiveness of CCS as a combined system, a discussion of the capture, transport and storage of CO_2 in boiler flue gases is presented.

As noted in Section 4.3.2.4 above, the method of CO_2 capture that is conceivable for the boiler flue gases are separation by absorption into an amine solvent. Amine solvent absorption has been proven in natural gas purification and ammonia production applications.

The cost figures for the amine treating system and compression system were included in the cost scenario evaluated by Ticona. The cost scenario is comprised of a new amine treating system and a new boiler for the amine treating system as well as compression for CO_2 transport to a nearby abandoned gas field, storage cavern, or equivalent, pipeline materials, operation and maintenance costs associated with these components, and other costs such as property taxes and insurance. The costs associated with storage of CO_2 are not included in the cost estimates.

An additional new steam boiler would be required to operate CCS technology for the proposed Ticona Facility, because even with the three new boilers, the facility does not have sufficient excess steam. Ticona estimates that CCS would require 405,546 lbs/hr of steam in order to regenerate MEA. Ticona's existing and new steam capacity is sized for its current and expanded (i.e. Methanol) plant operations, and thus does not have enough excess steam to support CCS. Thus, a new steam boiler would be required to ensure CCS operation. The capital cost for the amine treating system and the compression system were estimated based on engineering estimates. The costs are summarized in the discussion below.

The estimated capital cost of an amine treating system used to capture 90% of flue gas CO_2 is $125,832,000 to provide a steam system (boiler, deaerator, condensate receiver, boiler feedwater pumps, condensate return pumps, etc.) producing of 90-psig saturated steam to regenerate the MEA in the system. The cost of natural gas for the boiler would be $11,724,000/yr, assuming a natural gas price of $2.77/MMBtu, an 80% boiler efficiency, and an operational period of 8,760 hr/yr. The MEA system would require 6,786 HP, of electricity for pumps and air coolers. An additional 7,230 HP would be required for CO_2 compression. Assuming $27.70 per MW-hr, the electricity costs of capture and compression are a total $2,790,000/yr. Labor costs associated with capture and compression are estimated at $1,000,000/yr. Maintenance, property taxes, and insurance are based on 3.2% of the capital cost, and equal $4,027,000/yr.

An assumed 200 miles of pipeline would be required to transport the captured CO_2 to an abandoned gas field, storage cavern, or equivalent (such as the Denbury pipeline). The costs associated with 8" pipeline transfer were estimated using the methodology established in guidance from the National Energy and Technology Laboratory's *Carbon Dioxide Transport and Storage Costs in NETL Studies* (DOE/NETL-2013/1614)[3]. The materials, labor, right of way, pipeline control system and miscellaneous costs total a capital cost of $139,300,000 with an additional $1,690,800/yr for operation and maintenance.

Thus, the future annualized cost for a CCS System would be:

Cost Item	Cost ($/yr)	
30-year amortized capital cost of capture including new boiler	$	8,186,000
Annual cost for operation, maintenance, taxation, and insurance of capture	$	19,540,000
30-year amortized capital cost of pipeline transfer	$	9,062,000
Annual cost of operation and maintenance of pipeline transfer	$	1,691,000
Total	**$**	**38,479,000**

90% of captured CO_2 from boiler flue gas is estimated to be at 634,276 tpy. The new boiler required for an amine system would generate an additional 250,413 tpy CO_2; therefore, the CO_2 emissions avoided by capture would be a difference of approximately 383,863 tpy. CCS is determined to not be cost effective as the annualized costs equate to ~ $100.24 per ton CO_2 avoided and would increase current project capital costs by more than 100%.

4.3.4.2 *Selection of the Lowest Carbon Fuel*

Natural gas is the lowest emitting carbon fuel that could be relied upon for the proposed operation. The natural gas usage will be offset when practicable with process gas.

[3] http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/QGESS_CO2T-S_Rev2_20130408.pdf

4.3.4.3 *Installation of Energy Efficiency Options on the Boilers*

The design of the new boilers will incorporate the energy efficiencies described in Section 4.3.1.2. The technologies being employed are proven and can be implemented to increase the energy efficiency from the unit. All technologies described above will be utilized in the process design.

4.3.4.4 *Best Operational Practices*

The implementation of regular maintenance, monitoring, and minimizing uncontrolled emissions during start-up, shutdown and maintenance will be utilized to maintain the system performance and minimize GHG emissions.

4.3.5 Step 5 – Selection of GHG BACT

Based on the top-down process described above for control of GHG emissions from the boilers, Ticona is proposing that BACT the use of natural gas as the primary fuel and the above described energy efficiency and best operational practices options. This is consistent with other control options found in the RBLC Clearinghouse.

4.4 GHG BACT Evaluation for Fugitives Emissions

The following section proposes appropriate GHG BACT emission limitations for fugitive CO_2 and CH_4 emissions. The fugitive emission controls presented in this analysis will provide similar levels of emission reduction for both CO_2 and CH_4, therefore, the BACT evaluation for these two pollutants has been combined into a single analysis.

4.4.1 Step 1 – Identify all Control Technologies

In determining whether a technology is available for controlling GHG emissions from fugitive components, permits and permit applications and U.S. EPA's RBLC were consulted. Based on these resources, the following available control technologies were identified:

- Installation of leakless technology components to eliminate fugitive emission sources;
- Implementing various LDAR programs in accordance with applicable state and federal air regulations;
- Implement alternative monitoring program using a remote sensing technology such as infrared camera monitoring;
- Implementing an audio/visual/olfactory (AVO) monitoring program for compounds; and
- Design and construct facilities with high quality components, with materials of construction compatible with the process.

4.4.2 Step 2 – Technical Feasibility Analysis

Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some leakless technologies, such as bellows valves, if they fail, cannot be repaired without a unit shutdown that often generates additional emissions.

LDAR programs have traditionally been developed for control of VOC emissions. BACT determinations related to control of VOC emissions rely on economic reasonableness for these instrumented programs. The adverse impact of fugitive emissions of CH_4 and CO_2 due to their global warming potential has not been quantified, and no reasonable cost effectiveness has been determined. Monitoring direct emissions of CO_2 is not feasible with the normally used instrumentation for fugitive emissions monitoring. Instrumented monitoring is technically feasible for components in CH_4 service.

Alternate monitoring programs such as remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.

Leaking fugitive components can be identified through Audio/Visual/Olfactory (AVO) methods. Ticona's pipeline natural gas does not have Mercaptan added for leak detection. Thus, leaks from natural gas components cannot be detected by olfactory methods. Therefore AVO is not a technically feasible method of control.

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. For example, a valve that has been manufactured under high quality conditions can be expected to have lower run out on the valve stem, and the valve stem is typically polished to a smoother surface. Both of these factors greatly reduce the likelihood of leaking. The boilers at Ticona's Bishop Facility will be constructed with compatible components and designed with gaskets and other materials of construction for the service for which they are intended.

4.4.3 Step 3 – Rank of Remaining Control Technologies by Effectiveness

The most effective control issuing Leakless technologies. Leakless technologies are highly effective in eliminating fugitive emissions from the specific interface where installed, however leak interfaces remain even with leakless technology components in place. In addition the sealing mechanism, such as a bellows valve, is not repairable online and may leak in the event of a failure until the next unit shutdown.

Instrumented monitoring is effective for identifying leaking CH_4, but may not be effective for finding leaks of CO_2. With CH_4 having a global warming potential greater than CO_2, instrumented monitoring of the fuel and feed systems would be the second most effective method for control of GHG emissions. TCEQ's 28VHP LDAR monitoring program is stated as BACT for facilities emitting greater than 25 tpy of VOC in TCEQ BACT guidance. The 28VHP programs requires a quarterly instrumented monitoring with a leak definition of 500 ppmv for valves and connectors and 2,000 ppmv for pumps and compressor seals, and has a control effectiveness of 97% and 85%, for valves/connectors and pumps/compressors respectively. For uncontrolled SOCMI service without ethylene, the leak rate for gas/vapor valves is 0.0089 lb/hr and for gas/vapor connectors the rate is 0.0029 lb/hr. Component reductions are therefore 0.0086 lb/hr and 0.0028 lb/hr with quarterly 28VHP instrumented monitoring.

Remote sensing using infrared imaging has proven effective for identification of leaks. The process has been the subject to EPA rulemaking for an alternative monitoring method to Method 21. Effectiveness is likely comparable to EPA Method 21 with cost being included in the consideration.

Use of high quality components is effective in preventing emissions of GHGs, relative to use of lower quality components.

4.4.4 Step 4 – Top-Down Evaluation of Control Options

Leakless technologies have not been adopted as BACT, or even as Maximum Achievable Control Technology (MACT) Standards meant for hazardous compounds. Given methane's low toxicity relative the hazardous compounds regulated by MACT, it is reasonable to state that these technologies are impractical for control of GHG emissions whose impacts have not been quantified. Any further consideration of available leakless technologies for GHG controls is unwarranted.

The use of instrumented leak detection and infrared monitoring are technically feasible for methane. Both detection methods have been demonstrated to be comparable, based on EPA's presentation of the infrared monitoring as an acceptable alternative.

Design to incorporate high quality components is effective in providing longer term emissions control because components with greater mechanical integrity are less apt to leak.

4.4.5 Step 5 – Selection of CH4 BACT for Fugitive Emissions

Ticona proposes to utilize Method 21 instrumented monitoring equivalent to TCEQ VOC BACT as GHG BACT. Ticona proposes to monitor via instrumented Method 21 monitoring components in greater than 10% by weight of CH_4.

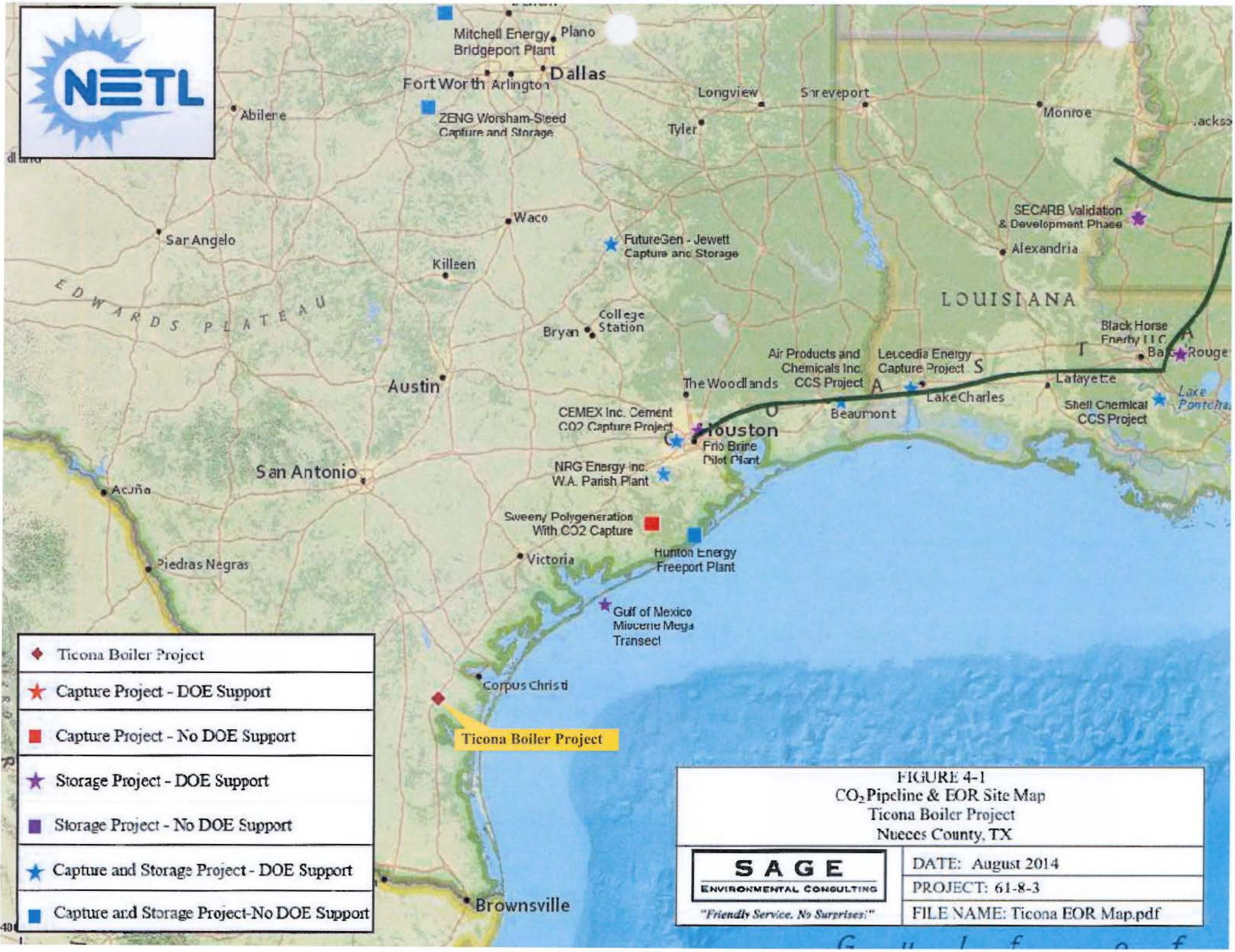


FIGURE 4-1
CO_2 Pipeline & EOR Site Map
Ticona Boiler Project
Nueces County, TX

SECTION 5
MONITORING AND COMPLIANCE DEMONSTRATION

Ticona proposed the following compliance demonstrations that will be utilized during the boilers normal operation to show compliance with GHG emission limits and BACT requirements. Table 5-1 summarizes the proposed compliance demonstrations.

5.1 Boilers (EPNs: BOILER01, BOILER02, BOILER03)

The boilers emit almost all of the GHG emissions in the proposed application and will be equipped with monitoring and instrumentation sufficient to demonstrate the following:

- The boilers meet an annual CO_2e limit of 705,469 tpy; and
- The boilers' efficiency based on stack temperature.

Natural gas fed as fuel and/or raw material to the boilers and composition in combination with HHV for the fuel gas components, will be used to calculate the hourly heat input associated with boilers on a 12 month basis. The natural gas flow to the boilers will be continuously monitored and recorded in a data historian. Per 40 CFR § 98.34(b)(1)(ii), the GHG Mandatory Reporting Rule, the fuel flow meter will be calibrated at least annually, or at the minimum frequency established per manufacturer's recommendation, or at the interval specified by industry standard practice. The natural gas composition will be determined by sampling and analysis in accordance with 40 CFR § 98.34(b)(3) or per the natural gas vendor. The concentration of the fuel gas components will be used to determine CO_2e emissions on a 12-month rolling basis.

Heat input, composition, and flow will be used to calculate GHG emissions from the boilers consistent with the methodology found in this application on calendar month basis. Compliance with the annual permitted emission limits will be evaluated against the rolling 12-month actual emission rate.

Thermal efficiency will be calculated monthly to demonstrate if it is at or above 77%.

O_2 will be measured by an O_2 CEMS in the stack. Reliability of the measurement will be ensured by a weekly zero and span and a semi-annual cylinder gas audit and/or relative accuracy audit test (RATA).

The flow meters, analyzers, and temperature monitoring equipment used for boiler compliance will be operated at least 95% of the time when the boilers are operational, averaged over a calendar year.

5.2 Fugitives (EPN: BLRFUG)

The CO_2e emissions estimated from equipment leaks in new and modified piping and equipment amount to 17 tpy, or less than 0.01% of the total CO_2e emissions from the project.

Tracking emissions against a numeric limit is considered infeasible due to the insignificant quantity of emissions expected and the unpredictability of component leaks. Ticona proposes follow the monitoring, recordkeeping, and repair practices of Texas's 28VHP fugitive monitoring program to ensure the minimization of GHG emissions from fugitive components containing greater than 10%-wt CH_4. The 28VHP monitoring program meets and/or exceeds BACT requirements for equipment fugitive components.

5.1 Emergency Engine (BLRGEN)

A diesel-fueled emergency generator with a rating no greater than 350 KW will be installed to supply power to critical sources during an emergency. Estimated CO_2e emissions from these engines are insignificant compared to that of the project, and compliance with a CO_2e limit is considered infeasible. The non-emergency hours that the engine will operate will be limited to 100 hours per year each, in accordance with applicable NSPS IIII and MACT ZZZZ requirements, and will be monitored and recorded by a non-resettable run time meter.

Table 5-1 Proposed Compliance Demonstration By Source

GHG Emission Unit	EPN	Emission Limit or Standard	Monitoring/Testing	Recordkeeping
Fugitives	BLRFUG	None - Limit infeasible because emissions < 0.01 % of total	28VHP Fugitive emission monitoring program for streams containing > 10% wt CH_4.	Data will be maintained in accordance with the 28VHP program.
Boilers	BOILER01, BOILER02, BOILER03	705,469 tpy CO_2e, 12 month rolling	Natural gas composition will be determined by semiannual sampling and analysis or obtained quarterly from vendor's analysis. Process gas composition will be based initially on the application information, then updated with representative gas samples taken during any required CO_2 testing. Flow meters will continuously measure the fuel flows to the boilers. The flow meters will be calibrated per manufacturer's recommendation. The monitoring equipment will have at least 95% online reliability when the boilers are in operation and not being calibrated, averaged over a calendar year.	Block one-hour fuel flow records and all concentration data will be maintained. CO_2e emission will be calculated on a 12-month rolling average.
		N/A	An O_2 CEMS will be installed on each boiler's stack and record O_2 concentration daily. Zero and span calibrations will be performed weekly. In additional, semi-annual cylinder gas audits and/or RATA will be performed.	Daily O_2 measurements will be recorded.
		77% Thermal Efficiency on HHV basis	Fuel flows, fuel heat content, O_2 concentration, and stack temperature will be used to calculate the thermal efficiency.	Data will be calculated monthly.

GHG Emission Unit	EPN	Emission Limit or Standard	Monitoring/Testing	Recordkeeping
Emergency Engine	BLRGEN	CO_2e limit infeasible because emissions < 0.01% of total CO_2e.	A non-resettable runtime meter will be installed on each engine.	Monthly engine runtimes meter reading.
		100 hr/calendar year non-emergency use.		

SECTION 6
OTHER ADMINISTRATIVE REQUIREMENTS

6.1 Other Administrative Information

The following administrative information related to this permit application is provided in the following Table:

- Company name:

  Ticona Polymers, Inc.

- Company official and associated contact information:

  Brian E. Connelly

  Brian.Connelly@Ticona.com

- Technical contact and associated contact information:

  William Chidester

  361-584-6614

  William.Chidester@celanese.com

- Project location, Standard Industrial Code (SIC), and North American Industry Classification System (NAICS) code:

  5738 County Road 4, Bishop, TX 78343

  SIC: 2869; NAICS: 325199

- Projected start of construction and start of operation dates; and

  Start of Construction: January 2016

  Start of Operation: March 2017

APPENDIX A
GHG EMISSION CALCULATIONS

The following tables are included in this appendix in the following order:

- GHG Emissions Summary by Source;
- Boiler Emissions Calculations;
- Carbon Content Calculations;
- Fugitive Emissions Calculations;
- MSS Emissions Calculations; and
- Carbon Transfer and Storage Cost Calculations.

GHG Emissions Summary

EPN	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	CO_2e (tpy)
BOILER01	234,917	4	0.44	235,156
BOILER02	234,917	4	0.44	235,156
BOILER03	234,917	4	0.44	235,156
BLRFUG	0.06	0.66	-	16.54
BLRMSS	-	0.96	-	24.11
BLRGEN	33.29	0.00	0.00	33.41
Total	704,785	15	1	705,543.08

Boilers (EPNs: BOILER01, BOILER02, BOILER03)

GHG Emissions Summary

EPN	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	CO_2e (tpy)
BOILER01	234,917	4	0.44	235,156
BOILER02	234,917	4	0.44	235,156
BOILER03	234,917	4	0.44	235,156

GHG Emission Calculations

Fuel component	GHG	Formula	Eq.	Applicability	Fuel flow[1] (scf/yr)	HHV[2] (MMBtu/scf)	CC[3]	MW[3]	Emissions (tonne/yr)	GWP factor	CO_2e (tonne/yr)	CO_2e (ton/yr)
Off gas	CO_2	44/12 * Fuel flow * CC * MW $_{fuel}$/836.6 scf/kg-mol * 0.001	C-5	98.33(b)(3)(ii)	350,400,000	0.0008604	0.55	22.49	19,017.65	1	19,018	20,963
	CH_4	0.001 * Fuel flow * HHV * 0.001	C-8	98.33(c)(1)					0.30	25	8	8
	N_2O	0.001 * Fuel flow * HHV * 0.0001	C-8	98.33(c)(1)					0.03	298	9	10
Natural Gas	CO_2	0.001 * scf fuel/yr * MMBtu/scf * 53.06	C-2a	98.33(b)(2)(ii), 98.33(b)(3)(ii)(A)	3,565,342,356	0.001026	-	-	194,095.67	1	194,096	213,954
	CH_4	0.001 * Fuel flow * HHV * 0.001	C-8	98.33(c)(1)					3.66	25	91	101
	N_2O	0.001 * Fuel flow * HHV * 0.0001	C-8	98.33(c)(1)					0.37	298	109	120
										Total	213,330	235,156

Example calculation (off gas CO_2):

44/12 *350400000 scf/yr * 0.55 kg C/kg fuel * 22.49/836.6 scf/kg-mol * 0.001 * = 19018 tonne/yr

Notes:

1. Fuel flow to boiler based on maximum heating value. The actual flows may vary, but the calculations represent maximum emissions.
2. Estimated heating value fonatural gas factor from Table C-1, 40 CFR Part 98.
3. See Carbon Content calculation.

Carbon Content (CC) Calculations
Process Gas[1,2]

Basis:

$CC = 12 * \Sigma(Ni * Xi) / \Sigma(Xi * Mi)$

where

CC =	Carbon content of process fuel (lb carbon/lb fuel)
Ni =	Number of carbons per molecule
Xi =	mole fraction of component
Mi =	MW of component

Component	Puge gas composition[2]	# carbons	MW	Purge gas	
	mol-frac		lb/lbmol	Ni * Xi	Xi * Mi
Methane	0.5792	1	16.04	0.5792	9.2908
Nitrogen	0.0501	0	28.01	0.0000	1.4044
Hydrogen Sulfide	0.0000	0	34.08	0.0000	0.0004
Carbon Dioxide	0.0731	1	44.01	0.0731	3.2173
Carbonyl Sulfide	0.0000	1	60.07	0.0000	0.0013
Hydrogen	0.1080	0	2.02	0.0000	0.2177
Ethanol	0.0008	2	46.07	0.0015	0.0346
Butanol	0.0001	4	74.12	0.0006	0.0108
Ethyl Acetate	0.0002	4	88.11	0.0006	0.0139
Acetaldehyde	0.1884	2	44.05	0.3769	8.3013
			Σ =	1.0319	22.4928
				Fuel Gas MW =	22.4928
				Fuel Gas Carbon Content =	**0.5505**

Notes:

1. As required by the GHG Monitoring and Reporting Rule, carbon content will be used to calculate GHG emissions for the process gas because the process gas in not a fuel listed in 40 CFR Part 98, Subpart C, Table C-1.
2. The values used in and determined by this calculation are estimations only, not limits upon which compliance shall be based.

Fugitive Emission Calculations
EPN: BLRFUG

			Valves	Connections - Flanges or Screwed	Relief Valves	Open-ended Lines	wt% Composition		Emissions					
Stream	LDAR Program	SOCMI Type	Gas/Vapor	Gas/Vapor	Gas/Vapor		Methane	Carbon Dioxide	Total Fugitives		Carbon Dioxide		Methane	
Factors		SOCMI w/o C2	0.0089	0.0029	0.2293	0.0038	%	%	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Factors	AVO*		97%	97%	97%	0%								
Factors	28VHP		97%	30%	97%	97%								
Process Gas	28VHP	SOCMI w/o C2	193	297	2	3	41.31	14.30	0.10	0.45	0.01	0.06	0.04	0.19
Natural Gas	28VHP	SOCMI w/o C2	181	371	4	0	100	0.00	0.11	0.47			0.11	0.47
GHG Total			374	668	6	3			-	-	0.01	**0.06**	**0.15**	**0.66**

Note:

*AVO factors are for odorous inorganic process lines.

Emission rates less than 0.005 lb/hr or tpy are represented as 0.00.

Does not represent all operating scenarios.

Zero emission components (double seal with barrier fluid, PSVs routed to control, PSVs with a rupture disk, etc) are not represented above.

MSS Emissions (CO_2e)
EPN: BLRMSS

Emissions Basis
Maximum volume vented when isolating section of natural gas pipe for maintenance, start-up or shutdown

Annual volume cleared	15000	ft^3/yr	
Pressure	44.7	psia	
Temperature	60	F	
Gas Constant	10.73	ft3 * psia / (R * lbmol)	
Methane MW	16.04	lb/lbmol	
Methane Annual emissions	1928.75	lb/yr	0.96 tpy
Total CO2(e)	24.11	tpy	

Notes:
Emissions vented to atmosphere determined using Ideal Gas Law and volume of system cleared.
Actual conditions including temperature and pressure may vary.

Example calculation:
15000 ft^3 * 44.7 psia / 10.73 ((ft^3- psia) / (R-lbmol)) / (60 + 459.67 R) * 16.04 lb/lbmol *1 ton/2000 lb * 25 = 24.11 tpy CO_2e

Estimated Cost for Carbon Transfer and Storage

CO_2 Transfer and Storage Data

Pipeline Length	200	miles
Pipeline Diameter	8	inches

Equations below from: The National Energy Technology Laboratory guidance, "Carbon Dioxide Transport and Storage Costs in NETL Studies," DOE/NETL - 2013/1614, March 2013

Cost Type	Units	Cost		
Pipeline Costs				
Pipeline Materials	$ Diameter (inches), Length (miles)	$70,350+ $2.01 x L x (330.5 x D^2 + 686.7 x D + 26,920)	$	21,603,721
Pipeline Labor	$ Diameter (inches), Length (miles)	$371,850 + $2.01 x L x (343.2 x D^2 + 2,074 x D + 170,013)	$	84,216,910
Pipeline Miscellaneous	$ Diameter (inches), Length (miles)	$147,250 + $1.55 x L x (8,417 x D + 7,234)	$	23,263,950
Pipeline Right of Way	$ Diameter (inches), Length (miles)	$51,200 + $1.28 x L x (577 x D + 29,788)	$	8,858,624
Other Pipeline Capital				
CO_2 Surge Tank	$	1,244,724	$	1,244,724.00
Pipeline Control System	$	111,907	$	111,907
		Total Pipeline Capital	$	139,299,836
O&M Pipeline				
Fixed O&M	$/mile/year	$8454 x L	$	1,690,800
		Total O&M Pipeline	$	1,690,800