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18 February 2013

Mr. Jeff Robinson
Chief, Air Permit Section
Air Permits Division
U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202

RE: Initial Greenhouse Gas Air Permit Application for New Natural Gas to Gasoline Plant
Natgasoline, LLC, Beaumont, Texas Facility

Dear Mr. Robinson:

On behalf of Natgasoline, LLC, Weston Solutions, Inc (WESTON®) submits the enclosed electronic copy of the initial Prevention of Significant Deterioration (PSD) greenhouse gas (GHG) air permit application for a new natural gas to gasoline plant to be constructed and operated in Beaumont, Texas.

A separate PSD air permit application for pollutants other than regulated GHG pollutants was delivered to the Texas Commission on Environmental Quality (TCEQ) Austin office on 16 January 2013. A copy of the TCEQ application was also provided to your attention.

If you have any questions regarding this submittal, please contact me at (512) 651-7148 or via email at Blake.Soyars@westonsolutions.com.

Very truly yours,
WESTON SOLUTIONS, INC.

Blake Soyars

Blake Soyars, P.E.
Client Service Manager

INITIAL EPA GHG AIR PERMIT APPLICATION FOR A NEW NATURAL GAS TO GASOLINE PLANT

Prepared for

Natgasoline, LLC
Beaumont, Texas

Prepared by

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February 2013

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ASU	air separation unit
BACT	Best Available Control Technology
bbl	barrel
CFR	Code of Federal Regulations
CO	Carbon Monoxide
DME	dimethyl ether
DRE	destruction removal efficiency
dscf	Dry Standard Cubic Foot
EPN	Emission Point Number
GHG	greenhouse gas
GtG	Gas to Gasoline
HAP	hazardous air pollutants
H_2S	Hydrogen Sulfide
HGT	heavy gasoline treatment
IFR	internal floating roof
IR	infrared
LAER	Lowest Achievable Emission Rate
Lb/hr	pounds per hour
LDAR	leak detection and repair
LEL	lower explosive limit
LPG	liquid petroleum gas
MACT	Maximum Achievable Control Technology
MeOH	Methanol
MMBtu/hr	10^6 British Thermal Units per hour
MMgal/yr	10^6 gallons per year
MSS	maintenance, startup, and shutdown
MtG	Methanol to Gasoline
NAAQS	National Ambient Air Quality Standards
NNSR	Non-attainment New Source Review
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
NSR	New Source Review
NSRPD	New Source Review Permits Division

PM	Particulate Matter
ppmvd	Parts Per Million, Volumetric Dry
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
PTE	potential to emit
RN	regulated entity number
RVP	Reid Vapor Pressure
SCR	selective catalytic reduction
SO_2	Sulfur Dioxide
TAC	Texas Administrative Code
TCAA	Texas Clean Air Act
TCEQ	Texas Commission on Environmental Quality
tpy	short ton per year
VCU	vapor combustion unit
VFR	vertical fixed roof
VOCs	volatile organic compounds

1. INTRODUCTION

Natgasoline, LLC (Natgasoline) proposes to construct a new motor-grade gasoline production facility in Nederland, Texas that uses natural gas as feedstock. The proposed new facility will include two main process units. The first process unit is identified herein as the "Methanol Unit" and it will convert natural gas and water into methanol. The second process unit is identified herein as the "Methanol-to-Gasoline (MtG) Unit" and it will convert methanol into motor vehicle gasoline and water. With this substantial investment in the Beaumont area, Natgasoline plans to:

- create over 130 permanent new jobs;
- construct the first Gas to Gasoline (GtG) plant in the United States (U.S.); and
- create a new commercially viable pathway to reduce foreign oil demand by leveraging natural gas (the fastest growing domestic energy resource in the U.S.) to manufacture gasoline.

With this application, Natgasoline requests a Greenhouse Gas (GHG) air quality permit authorization to construct and operate the proposed new GtG facility in Nederland, Texas. This initial GHG permit application is provided consistent with the requirements in Title 40, Part 52 of the Code of Federal Regulations (40 CFR 52) and specifically with the §52.21 Prevention of Significant Deterioration (PSD) requirements. The new GtG facility will be an independent source for purposes of the PSD permitting rules as discussed in Section 1.2 below.

An area map showing the location of the proposed new GtG facility is included in this section as Figure 1-1. A facility plot plan for the proposed new GtG plant is included as Figure 1-2.

1.1 PROJECT OVERVIEW

Natgasoline is proposing to construct a motor-grade gasoline production plant in Nederland, Texas. The new plant will have two primary process units:

- A 5,500-metric ton per day (tpd) methanol production unit that synthesizes refined methanol using natural gas feedstock and water; and
- A 22,000-barrel per day (bpd) gasoline production unit that synthesizes gasoline and water using the refined methanol from the proposed new methanol production unit or other off-site sources.

New process equipment associated with this project includes external combustion sources (ex. process heaters), flare, cooling tower, storage tanks, and liquid loading with associated piping and other equipment components. The new GtG facility will be authorized under a new PSD permit.

1.2 DEFINITION OF STATIONARY SOURCE

For purposes of air permitting, the Natgasoline GtG plant is proposed as a separate, new stationary source. Natgasoline is a recently incorporated company that does not own or operate any other facility in the area of the proposed GtG plant. Ownership, operational control, and management of the Natgasoline GtG plant will be entirely independent from any other existing facility. As a stand-alone new source, the proposed new GtG plant will constitute a major source for PSD applicability evaluation purposes, as discussed in Section 1.3 below.

1.3 PSD APPLICABILITY EVALUATION

This application is to request PSD permit authorization as required for emissions of GHG air pollutants as regulated under 40 CFR §52.21. The new GtG facility must be evaluated to determine whether it is a "major source" as defined in §52.21(b)(49)(iv)(*b*). Therefore, the steps to determine PSD applicability for GHG emissions were completed as follows:

1. Because this is a proposed new source, the emissions increases associated with the proposed new GtG facility were estimated to determine if project-related increases would exceed the major source threshold for regulated PSD pollutants. The major source threshold is 100 ton per year (tpy) because the proposed facility is a chemical manufacturing facility, which is one of the categories listed in §52.21(b)(1)(i)(*a*).

2. Project-related emissions increases of several regulated PSD pollutants were determined to exceed the PSD Significance Levels. Therefore, the proposed source construction meets the PSD applicability criteria of being considered a "major source."

3. Because it will be located on a completely new site, there will be no projects to evaluate for netting other than the new emissions from the proposed new plants. Therefore, the project-related emission increases are equal to the net emission increases.

4. The project-related emissions increase totals were determined to exceed the PSD Significance Levels of the regulated GHG pollutants; therefore, the proposed project is subject to PSD permitting requirements for GHG pollutant emissions.

PSD applicability tables are included in Appendix C, and project-related emissions are detailed in Appendix D. Because this is a proposed new source and there are no contemporaneous projects to evaluate, the PSD netting tables are not included in Appendix C. Table D-1 (in Appendix D) summarizes the project-related emission increases, and Appendix C provides additional PSD emission summaries and PSD applicability analysis information.

The proposed Natgasoline project will be subject to PSD permitting for regulated air pollutants other than GHG pollutants, and the project will comply with all applicable PSD permitting requirements for all pollutants that are subject to PSD as specified in 40 CFR §52.21. On 16 January 2013, Natgasoline delivered a separate PSD air permit application to the Texas Commission on Environmental Quality (TCEQ) covering all regulated PSD pollutants except for GHG pollutants. Natgasoline will provide air pollutant dispersion modeling analyses to the TCEQ to demonstrate that the proposed new source will not cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) as specified in §52.21(k). Based on §52.21 and related EPA guidance documents, Natgasoline understands the following with regard to other evaluations that are required for PSD permitting of regulated GHG pollutants:

- EPA has not established NAAQS specific to regulated GHG pollutants.
- Air dispersion modeling of the regulated GHG pollutants is not required under §52.21(k) at this time.
- Preconstruction air quality monitoring of regulated GHG pollutants is not required under §52.21(m)(1)(ii) at this time.

Additional impacts analysis of regulated GHG pollutants on designated Class I areas is not required under §52.21(o) at this time. In any case, the proposed project is located more than 500 kilometers from the nearest designated Class I area, which is the Caney Creek Wilderness Area in Arkansas.

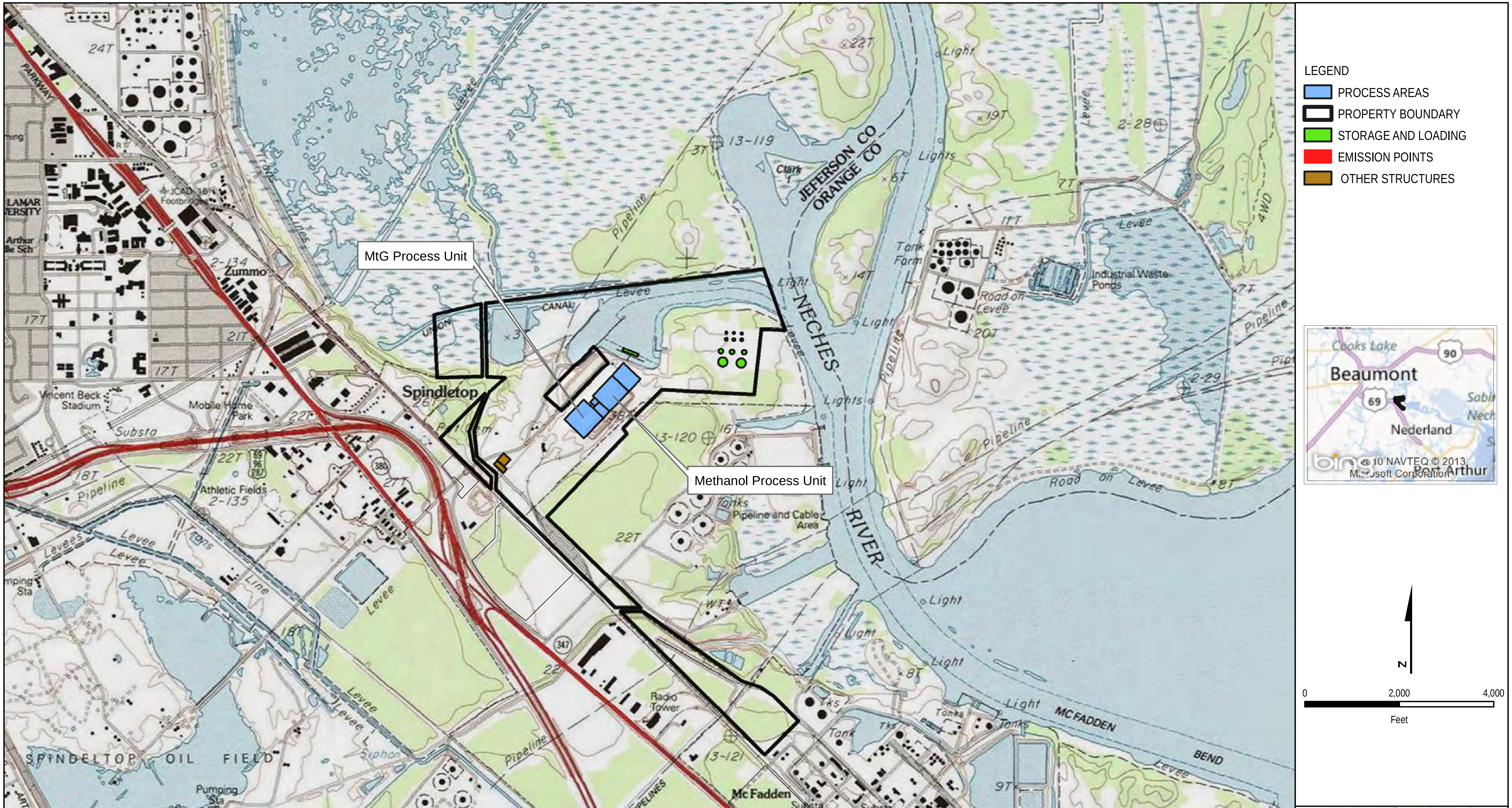

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FIGURE 1-1

GtG PLANT

NATGASOLINE, LLC
NEDERLAND, TX

DATE	PROJECT NO	SCALE
FEB 2013	15089.001.001	AS SHOWN

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FIGURE 1-2

PLANT LAYOUT

NATGASOLINE, LLC
NEDERLAND, TX

DATE	PROJECT NO	SCALE
FEB 2013	15089.001.001	AS SHOWN

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2. PROCESS DESCRIPTION

The proposed new GtG facility will be composed of two main process operations: the methanol unit and the MtG unit. The methanol unit will be designed to produce 5,500 ton per day of methanol from natural gas feedstock. The MtG unit will be designed to produce 22,000 barrels per day of gasoline from methanol feedstock. The GtG Plant will also be supported by utility operations and other ancillary equipment as described below. Process flow diagrams for the methanol unit and MtG unit are provided at the end of this section as Figures 2-1 and 2-2, respectively.

2.1 METHANOL UNIT PROCESS DESCRIPTION

The proposed new methanol unit will synthesize methanol using natural gas as feedstock. Natural gas will be delivered to the methanol unit by pipeline. The majority of the natural gas received by the facility will be used as chemical feedstock for the methanol process, and a portion of the natural gas will be burned as fuel. The chemical feedstock portion of the natural gas will first be treated to remove sulfur compounds and then otherwise pretreated for use in the methanol process.

The pretreated natural gas feedstock will be combined with steam and recycled process gases and routed to the reforming section of the methanol unit. The reforming section will convert the methane, steam, and other compounds into synthesis gas (or “syngas”). Syngas is a gaseous mixture that includes varying concentrations of hydrogen, carbon monoxide, and carbon dioxide. The reforming section will include one primary reformer and one secondary reformer. The primary reformer will include a gas-fired combustion source (EPN: B-01001).

The syngas from the reforming section will be sent to the methanol synthesis section of the methanol unit, which contains a series of reactors that will convert the syngas into crude methanol. The crude methanol liquid from the reaction section will include water, liquid impurities, and dissolved gases that will be removed in downstream distillation operations.

During startup of the entire methanol unit, syngas that is normally fed to the methanol synthesis process will be routed to the process flare for a limited duration. With the exception of this startup operation, the methanol synthesis process section is an enclosed process that does not generate any waste gases or air pollutant emissions during normal operation, except for potential fugitive equipment leaks.

The crude methanol stream will be routed from the synthesis section to the distillation section, where the methanol will be fed through a series of distillation columns in order to remove the impurities, such as water, listed above. The effluent stream from this process will be the refined methanol product which will either be sent to storage for further processing in the MtG Unit or for product loading via shared methanol/gasoline barge, railcar, and truck loading facilities.

During startup of the entire methanol unit, a waste gas stream known as “expansion gas” will be routed from the methanol distillation process to the process flare for a limited duration. With the exception of this startup operation, the methanol distillation process is an enclosed process that does not generate any waste gases or air pollutant emissions during normal operation, except for potential fugitive equipment leaks.

2.2 MTG UNIT PROCESS DESCRIPTION

The proposed new MtG unit will synthesize motor-grade gasoline using methanol as feedstock. The methanol feedstock will generally be the methanol product from the proposed new methanol unit. However, the MtG unit will also be able to process methanol from other methanol manufacturers.

The methanol feedstock will be fed through a series of MtG reactors, which convert the methanol into a raw gasoline and liquefied petroleum gas (LPG) mixture. There will be six gas-fired process heaters associated with the MtG reaction unit: five reactor heaters associated with each MtG reactor (EPN: H-RXH1-5) that will supply heat to the reaction, and the regeneration heater (EPN: H-REGEN), which will periodically combust a carbonaceous (i.e., coke) deposit that will build up on the reactor catalyst during operation. The emissions from the catalyst regeneration vents (EPN: V-CATREGEN) will be routed to atmosphere only during catalyst regeneration events.

After the MtG reaction portion, the combined raw gasoline and LPG mixture will be sent to separation where it will be separated into three streams: 1) an LPG stream which will be sent to LPG storage, 2) a “light” gasoline stream that will be sent to gasoline blending and storage, and

3) a "heavy" gasoline stream that will be routed to the heavy gasoline treatment (HGT) for further processing.

The HGT unit will process heavy gasoline fraction from the separation portion in order to convert undesired components. The HGT feed stream will be heated using the HGT Treater Heater (EPN: H-HGT), and will then pass through a series of reactors that will convert selected components into more valuable hydrocarbon components. The HGT reaction section will produce an LPG stream that will be routed to LPG storage and a heavy gasoline stream that will be blended with the light gasoline stream from the separation portion and routed to product gasoline storage and loading.

Gasoline product loading will take place at the shared methanol/gasoline barge, railcar, and truck loading facilities.

2.3 SUPPORTING OPERATIONS

The proposed new GtG Plant will be supported by various auxiliary operations. An Air Separation Unit (ASU), owned and operated by a separate company, will be located at the site in order to provide oxygen to the secondary reformer (i.e., the ATR). An auxiliary boiler (EPN: B-14001) will be used to provide steam to the plant process units and the ASU. Additionally, a cooling water tower (EPN: T-06001) will provide the necessary process cooling water, and a plant flare (EPN: S-10001)/[MSS] will control emissions in cases of upset or emergency and planned maintenance, startup, and shutdown (MSS). An onsite wastewater treatment plant will receive and treat wastewater from the MeOH and MtG units.

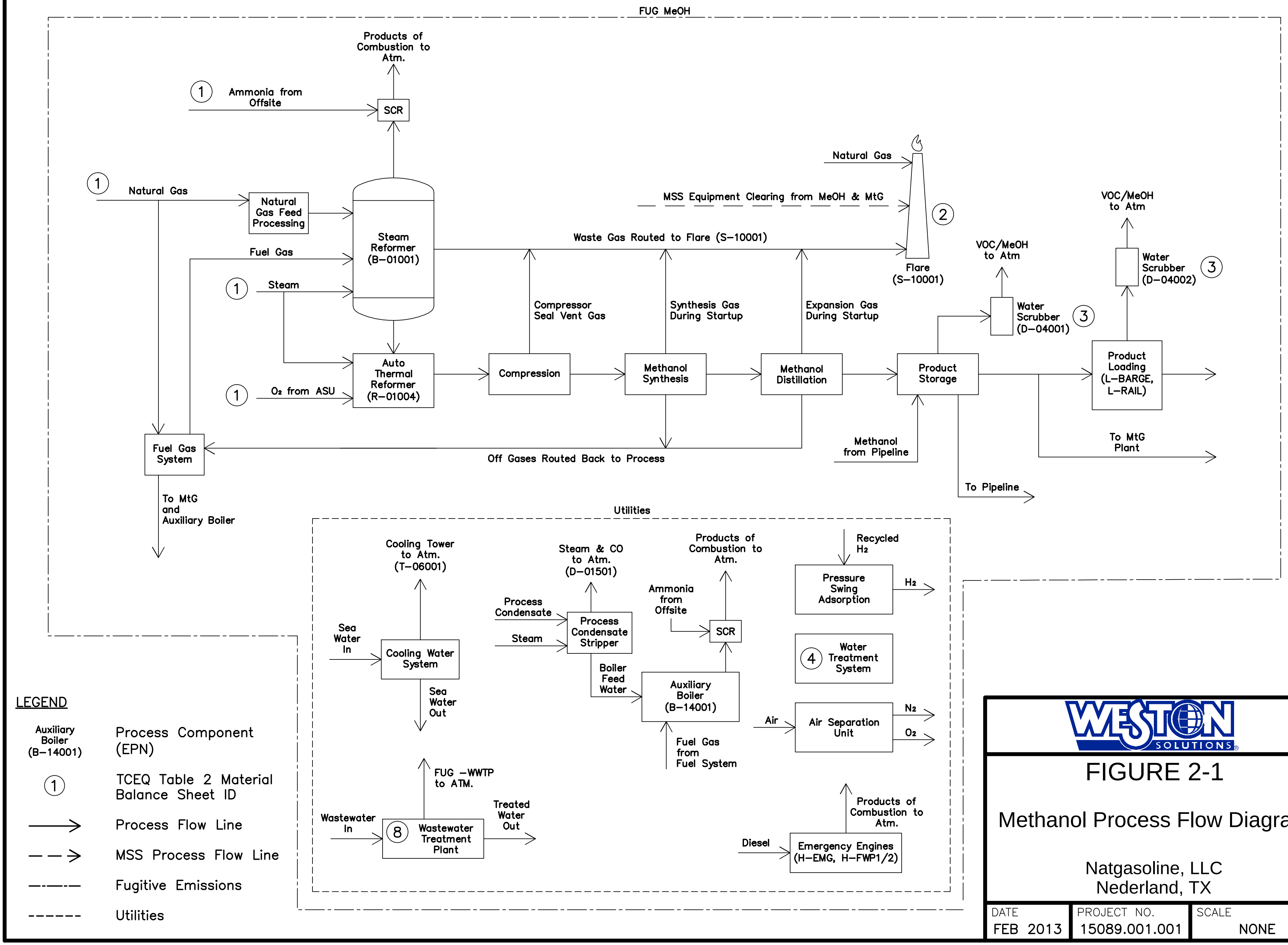

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FIGURE 2-1

Methanol Process Flow Diagram

Natgasoline, LLC
Nederland, TX

DATE	PROJECT NO.	SCALE
FEB 2013	15089.001.001	NONE

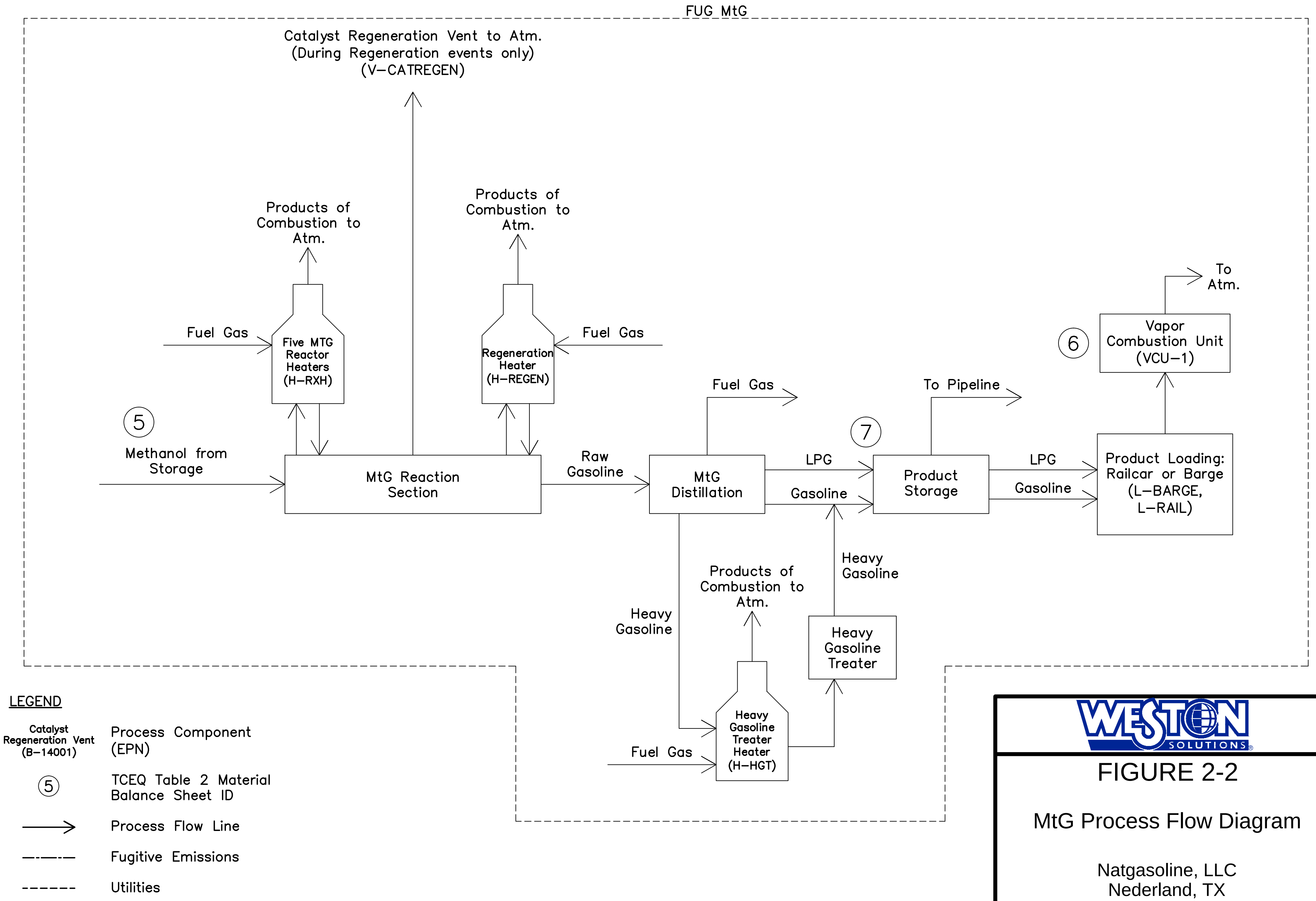

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FIGURE 2-2

MtG Process Flow Diagram

Natgasoline, LLC
Nederland, TX

DATE	PROJECT NO.	SCALE
FEB 2013	15089.001.001	NONE

3. EMISSION CALCULATIONS

The following sections describe GHG emission calculation methods applied to each source type associated with the proposed GtG project.

3.1 COMBUSTION SOURCES

Natgasoline proposes to construct nine new external combustion sources as part of the GtG project: the steam reformer (EPN: B-01001), auxiliary boiler (EPN: B-14001), and seven process heaters (EPNs: H-REGEN, H-RXH1-5, and H-HGT). GHG emissions from these nine combustion units were calculated using the proposed hourly and annual firing rates and GHG emission factors for natural gas fuel combustion from 40 CFR Part 98 Subpart C, Table C-1 and Table C-2. The CO_2 emissions from the steam reformer were based on fuel-specific carbon content, using the calculation methodology referenced to in 40 CFR Part 98 Subpart C, equation C-5. A process gas analyzer will emit very low quantities of GHG pollutants and these analyzer emissions are included as part of the calculated reformer emissions. Detailed emission calculations from the combustion sources are provided in Table D-2 in Appendix D.

3.2 PROCESS FLARE EMISSIONS

During normal operations, only natural gas (pilot gas and supplemental fuel) and compressor seal vent gas (process waste gas) will be combusted in the plant flare (EPN: S-10001). Emissions from the combustion of the pilot gas were calculated using estimated maximum hourly and annual pilot gas flow rates in conjunction with the emission factor for CO_2 from U.S. EPA's AP-42 Table 1.4-2 (July 1998) and emission factors for CH_4 and N_2O from 40 CFR Part 98 Subpart C, Table C-2.

The compressor seal vent gas is primarily comprised of nitrogen with some concentration (≤100 ppmv) of hydrocarbon contamination. There will also be some supplemental natural gas combined with this stream in order to raise the heating value of the waste gas to an acceptable level per §60.18. Emissions from the compressor seal vents were calculated using the estimated waste gas and supplemental natural gas flow rates and compositions and the appropriate emission factors. The CO_2 emissions were based on fuel-specific carbon content, using the calculation methodology referenced to in 40 CFR Part 98 Subpart C, equation C-5. Emissions of

N_2O were based on the emission factor 40 CFR Part 98 Subpart C, Table C-2. Emissions of CH_4 were based on the estimated concentration of CH_4 in the waste gas stream and a flare destruction efficiency of 99%.

Waste gas flaring will occur during periods of methanol unit startups. Specifically, synthesis gas and expansion gas process vents will be routed to the flare (EPN: S-10001[MSS]) during limited portions of the methanol unit startup operations. CO_2 emission rates from synthesis gas and expansion gas flaring events were calculated using the fuel-specific carbon content as specified in Equation C-5, which is the relevant calculation methodology in 40 CFR Part 98 Subpart C. N_2O emission rates were based on the emission factor 40 CFR Part 98 Subpart C, Table C-2. Emissions of CH_4 were based on the concentration of CH_4 in the waste gas stream and a flare destruction efficiency of 99%.

Waste gas flaring will also occur during equipment clearing for maintenance purposes. Flare emissions from planned clearing of equipment were calculated based on the flare burning a volume of saturated gasoline vapor with a small amount of residual liquid volume. Hourly equipment clearing emissions for the flare were calculated assuming the largest process vessel on-site would be cleared to the flare in a single hour. Annual equipment clearing emissions were calculated based on the maximum estimated number of planned plant shutdowns that would occur in any 12-month period, and each shutdown was assumed to include the total volume of all plant process equipment. These emissions calculation methods are intended to provide conservative potential GHG emissions estimates and should not be considered operational limits or constraints.

Emissions of CH_4 and N_2O from flaring during equipment clearing were calculated using the estimated organic vapor flow rates and emission factors from 40 CFR Part 98 Subpart C, Table C-1 and C-2. Global warming potential values in CO_2e were calculated based on the factors in 40 CFR Part 98 Subpart A, Table A-1. Detailed emission calculations from the flare are provided in Tables D-3 through D-7 in Appendix D.

3.3 VAPOR COMBUSTOR

Vapors collected from gasoline product loading operations will be routed to a vapor combustor (EPN: VCU-1) for control. CO_2 emissions from burning the collected loading vapors were calculated using the loading vapor loss calculations in U.S. EPA's AP-42 Section 5.2 (June 2008) and GHG emission factors from U.S. EPA's AP-42 Table 1.4-2 (July 1998). Detailed emission calculations from the vapor combustor are provided in Table D-8 in Appendix D.

3.4 FUGITIVE COMPONENTS

Fugitive emissions of methane were calculated based on the calculated VOC fugitive emission rates and the methane content of the fuel gas. VOC fugitive component leak emission factors were based on the estimated number of fugitive components and "SOCMI without Ethylene" factors from TCEQ's Technical Guidance Package for Equipment Leak Fugitives (November 2000). The monitoring credits were based on TCEQ's 28VHP leak detection and repair (LDAR) program. Total CH_4 emissions were calculated based the fuel gas containing 90% methane and 10% VOC by weight. Detailed emission calculations from the fugitive components are provided in Tables D-9 and D-10 in Appendix D.

3.5 PROCESS CONDENSATE VENTS

The process condensate stripper (EPN: D-01501) and process condensate degasser (D-05001) in the methanol unit will receive process condensate water from various processes. The condensate stripper will use steam stripping to remove gaseous contaminants, which will be routed through the stripper vent to the atmosphere. The vent stream will primarily be comprised of steam and air; however, a small amount of CO_2 and CH_4 will be emitted from the stripper vent. Emissions were calculated using the estimated vent flow rate and concentrations of CO_2 and CH_4. The condensate degasser will remove CO_2 from the wastewater stream (less than 1% by weight). There will be no CH_4 emissions from the condensate degasser vent. Detailed emission calculations from the process condensate vents are provided in Table D-11 in Appendix D.

3.6 CATALYST REGENERATION

The catalyst in the MtG reactors (EPN: V-CATREGEN) will be regenerated on a frequent basis to remove the coke that accumulates on the catalyst. The coke will be removed in a combustion process that will produce CO_2 emissions, which will then be routed to the atmosphere. There will be three different burns during the catalyst regeneration process: a main burn, a transition burn, and a clean-up burn. The three burns will use oxygen at varying flow rates and temperatures to remove any coke from the catalyst. Emissions were calculated using the estimated flue gas flow rates and CO_2 concentrations during the three different phases. Detailed emission calculations from the catalyst regeneration vents are provided in Table D-11 in Appendix D.

3.7 EMERGENCY GENERATOR AND FIREWATER PUMP ENGINES

Natgasoline proposes to construct one new diesel-fired emergency generator (EPN: H-EMG) and two diesel-fired firewater pump engines (EPN H-FWP1/2) as part of the GtG project. GHG emissions from the engines were calculated using the proposed hourly and annual firing rates and GHG emission factors for distillate fuel no. 2 combustion from 40 CFR Part 98 Subpart C, Table C-1 and Table C-2. Detailed emission calculations from the generator and engine are provided in Table D-2 in Appendix D.

4. BACT ANALYSIS

Every new source that is subject to PSD regulations for GHGs must perform a Best Available Control Technology (BACT) analysis as part of the PSD permit application. A BACT analysis is a structured evaluation of available emissions-reducing technologies or techniques including associated feasibility, energy, environmental, and economic aspects. The following BACT analysis is in support of a PSD permit application for GHG emissions associated with the new GtG plant proposed by Natgasoline. GHG emissions for the proposed project will be produced by individual sources of CO_2, CH_4, and N_2O emissions, including combustion units, process vents, and potential fugitive equipment leaks.

The EPA's "top-down" BACT Analysis methodology for GHG sources is outlined in PSD and Title V Permitting Guidance for Greenhouse Gases (EPA-457/B-11-001, March 2011) and includes the following steps:

Step 1: Identify all available control technologies.

Step 2: Eliminate technically infeasible options.

Step 3: Rank remaining control technologies based on control effectiveness.

Step 4: Evaluate most effective controls in terms of economic, energy and environmental impacts and document results.

Step 5: Select the BACT.

The top-down BACT review is the EPA's preferred methodology for a BACT analysis for pollutants and emission sources subject to PSD review; therefore, the top-down approach was followed in the BACT analysis for this GHG permit application.

The following new GHG-emitting source types are associated with this permit application and are subject to BACT requirements:

- Plant-wide;
- Steam reformer/process heaters;
- Auxiliary boiler;
- Flare;
- Vapor combustor;
- Process vents; and
- Equipment leak fugitive components.

In order to perform the BACT analysis for the above GHG emission sources, the following resources were utilized:

- EPA's Reasonably Available Control Technology/Best Available Control Technology/Lower Achievable Emission Rate Clearinghouse (RBLC) database;
- Approved GHG permit applications for similar source types in the state of Texas;
- EPA's *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, November 2010 (referred to herein as GHG BACT for Refineries);
- EPA's *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers*, November 2010 (referred to herein as GHG BACT for Boilers);
- Department of Energy's *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010; and
- Ernest Orlando Lawrence Berkeley National Laboratory's *Energy Efficiency Improvement and Cost Savings for the Petrochemical Industry*, July 2008.

Table E-1 in Appendix E of this application shows the proposed BACT limits (where applicable) and compliance demonstrations for each source of GHGs.

4.1 ALTERNATIVE METHANOL PRODUCTION PROCESSES

Methane reforming is the only available conversion process to support methanol production in quantities necessary for the viability of this project, although several different types of reforming are available as discussed below. At the most fundamental level, methane reforming consists of converting methane plus steam into a gas mixture known as "synthesis gas" (i.e., "syngas") that consists of hydrogen, carbon dioxide, and carbon monoxide, with low concentrations of methane. The synthesis process for converting syngas into methanol must be designed for compatibility with the selected methane reforming process, and the majority of all GHG emissions from the entire methanol unit will be generated in the methane reforming process and the associated auxiliary boiler. Therefore, selection of the methane reforming process design is the primary determinant for establishing the GHG emissions performance for the entire methanol unit.

For purposes of this BACT review, the appropriate source category definition for the methanol unit is a reforming process for converting natural gas methane into methanol. Consideration of other carbon feedstocks (e.g., coal or petroleum oil) would constitute redefinition of the proposed source, which is outside the scope of BACT evaluation requirements. Natgasoline evaluated all commercially available methane reforming process design types during the selection of the proposed reforming process design as the lowest GHG-emitting design basis that is technically feasible and economically reasonable within the appropriate source category definition. Within the proposed source category definition, Natgasoline evaluated the following reforming process design options for BACT selection purposes:

1. Steam methane reforming (SMR) only;
2. Autothermal reforming (ATR) only;
3. Partial Oxidation (POX) only;
4. Combined Gas Heated Reformer (GHR) and ATR; and
5. Combined SMR and ATR.

Following is a discussion of each above-listed design option to explain why the selection of combined SMR/ATR is BACT for GHG emissions.

Design Option 1 – Steam Methane Reforming (SMR) Only

The majority of existing methanol production plants use SMR-only reforming designs (i.e., without ATR). However, overall methanol conversion efficiency in a SMR-only process design is limited to approximately 90% maximum conversion of the feed methane, whereas Natgasoline's selected SMR/ATR design achieves almost 95% conversion of the feed methane. The SMR-only design option results in an unconverted 10% fraction of the feed methane that cannot be utilized in methanol production except to be burned as fuel or waste gas. As compared to the proposed combined SMR/ATR design, applying an SMR-only design would require 10% greater reformer firing rates to achieve the production rates necessary for this project. In summary, an SMR-only design is not BACT for this project because it would result in higher GHG emissions per unit of methanol produced as compared to the combined SMR/ATR design selected by Natgasoline for this project.

Design Option 2 – Autothermal Reforming (ATR) Only

No existing methanol production plants of reasonable size are based on ATR-only process design. As compared to the SMR-only process, the ATR-only design produces a syngas with different ratios of hydrogen to carbon oxides (i.e., CO_2 and CO). The syngas from an ATR-only process contains more carbon oxide than can be utilized in the process. Therefore, some syngas and purge gas from the synthesis would need to be processed in a hydrogen recovery unit (e.g., PSA) or additional hydrogen would need to be produced from the syngas with a shift reactor to make an ATR-only design technically feasible. With this theoretical ATR-only design, the hydrogen from the PSA would be mixed with the syngas to get the appropriate hydrogen to carbon-oxides ratio for methanol synthesis. This theoretical ATR-only design would need to include feed preheating and steam superheating, which would require relatively higher gas combustion with higher GHG emission rates as compared to the combined SMR/ATR design selected by Natgasoline. Therefore, even if combined ATR-only design were considered technically feasible (which has never been demonstrated), an ATR-only design is not BACT for this project because it would result in higher GHG emissions per unit of methanol produced as compared to the combined SMR/ATR design selected by Natgasoline for this project.

Design Option 3 – Partial Oxidation (POX) Only

Pure Non-Catalytic Partial Oxidation (POX) would potentially be associated with lower GHG emissions than a comparable SMR-only process. There are two large scale Fischer-Tropsch plants that generates syngas using this POX technology in operation. However, the use of this POX technology has led to immense cost and to multiple POX reactors, and, as such, this technology is considered to be technically and economically infeasible. Additionally, this POX technology is not available for licensing within the construction schedule required for this project, which further justifies the determination of technical infeasibility.

Design Option 4 – Combined Gas Heated Reforming (GHR)/ATR

A combined GHR/ATR design would potentially be associated with lower GHG emissions than the proposed combined SMR/ATR reforming process. However, no combined GHR/ATR methanol production process has ever been constructed with methanol production rates comparable to those necessary for the proposed Natgasoline project. Therefore, the combined GHR/ATR design is considered technically infeasible for this project.

Design Option 5 – Combined SMR/ATR

Combined SMR/ATR reforming is the lowest GHG emitting technology with proven technical feasibility and economic viability on a large scale, and at least four plants in operation around the world have established the minimum required confidence necessary to apply combined SMR/ATR technology to this project. The lower GHG emitting capability associated with combined SMR/ATR is mainly due to the ability to operate with a higher pressure in the syngas generation section (which results in a smaller SMR with a lower SMR flue gas temperature) and due to the favorable ratio of hydrogen to carbon oxides in the syngas. Natgasoline selected this technology as BACT for the proposed new methanol unit because the SMR/ATR design results in lower GHG emissions for each unit of methanol produced compared to every other process design with demonstrated capability to produce methanol at the rates necessary for this project.

4.2 ALTERNATIVE FUEL PRODUCTION PROCESSES

Based on the proposed gasoline synthesis process, Fischer-Tropsch is an alternate design basis for converting syngas into liquid fuels. Fischer-Tropsch synthesis is used in natural gas-to-liquid and coal-to-liquid processes. However, the Fischer-Tropsch process would convert the synthesis gas into a wide variety of different products (e.g., mainly wax, and then oxygenates like alcohols, aldehydes, carbonic-acids, and unsaturated hydrocarbons). The wax would require further treatment in order to produce gasoline and diesel. This process would generate significantly more GHG emissions to produce the commercial-grade fuels than the proposed natural gas to methanol to gasoline process proposed by Natgasoline. Therefore, the Fischer-Tropsch process would not be considered BACT.

4.3 PLANT-WIDE SOURCES

Step 1 – Identification of Potential Control Technologies

Carbon Dioxide Capture and Sequestration (CCS): CCS technologies involve the separation, collection, and compression of CO_2 gas from point source emissions, transportation of the compressed CO_2 gas to an on-site or off-site storage facility, and sequestering of the CO_2 in a viable storage facility.

The proposed Natgasoline GtG plant will emit CO_2 from a number of different processes and emission points throughout the facility. The consideration of the CCS at this site would likely be limited to the larger CO_2-emitting stacks, such as the reformer and the~~,~~ auxiliary boiler~~, and process heaters~~. The capture of the CO_2 gas emissions would require separation of the CO_2 gas from the combined combustion exhaust flows using a CO_2 separation process.

The proposed facility will not have on-site CO_2 storage. Therefore, any CO_2 captured and compressed would need to be transported off-site via a third party CO_2 pipeline system. The United States already presently has more than 3,000 miles of CO_2 pipelines used to transport CO_2 for Enhanced Oil Recovery (EOR).

Captured, compressed, and transported CO_2 may be stored or sequestered by means of currently available methods, including storage in geologic formations, EOR, and injection of CO_2 into an active oil reserve, brine aquifer, un-mined coal seam, basalt rock formation, or an organic shale bed. The U.S. Department of Energy (DOE) has been supporting Regional Partnerships that are initiating large-scale tests to determine how geologic storage reservoirs and their surrounding environments respond to large amounts of injected CO_2 in a variety of geological formations and regions across the United States. Because CO_2 storage is still an emerging technology, regulations and standards have not been developed.

Step 2 – Technical Feasibility

The process of CO_2 capture concentrates the CO_2 stream so it can be transported and/or stored. To date, successful CCS implementation has only involved highly concentrated CO_2 streams for practical and economic reasons.

The CO_2 must be separated from the combustion flue gas by a complex process that 1) filters out particulates, 2) cools the flue gas, and 3) compresses and separates the CO_2 (most likely via an amine absorption system). This process would require the installation of equipment that would otherwise not be used at the facility. For example, the separated CO_2 stream requires large compression equipment, capable of acidic gas handling (since CO_2 is highly corrosive) and high energy consumption to pressurize the gas for pipeline transportation. The energy demand that would be required to operate a carbon capture system would potentially require the construction and operation of a cogeneration unit (cogen unit). A cogen unit could be associated with a significant amount of emissions of GHGs and other regulated pollutants that would require additional controls. Although a CCS system would be technically challenging, it may not be infeasible and therefore needs to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Rank remaining control technologies based on control effectiveness

The economic reasonableness assessment is based on a 90% capture efficiency of the following CO_2-emitting sources at the site:

- Reformer Heater (EPN: B-01001);
- Auxiliary Boiler (EPN: B-14001);
- Regeneration Heater (EPN: H-REGEN);
- Five MtG Reactor Heaters (EPN: H-RXH); and
- Heavy Gasoline Treater Heater (EPN: H-HGT).

These nine sources contribute 95% to the total CO_2e emissions. Therefore, a CCS system for these sources would be the most effective method of controlling site-wide CO_2 emissions.

Step 4 – Evaluate most effective controls in terms of economic, energy and environmental impacts and document results

A search of the EPA RBLC database revealed no facilities listed as using CCS for BACT. However, though some aspects of CCS may prove it to be technically challenging, economics is the primary consideration in the BACT analysis. Natgasoline has performed a rough order of magnitude cost analysis for the above-mentioned sources of GHG. Table 4-1 on the following page summarizes the cost of carbon capture and compression, transport, and storage. The cost of CCS for the project is estimated to be $110 per ton of CO_2e controlled. The total annual cost of CCS technology to control all sources of GHG emissions is over $105,000,000. These costs are not considered to be effective for GHG control and, if required, would make the entire proposed project economically unviable. Therefore, CCS is not selected as a control option, and no further analysis will be considered in this permit application documentation.

Table 4-1
Cost of CO_2 Capture and Sequestration

CCS System Component	Cost [(1)] ($/ton of CO_2 Controlled)	Tons of CO_2 Controlled per Year [(5)]	Total Annual Cost
Carbon Dioxide Capture and Compression [(2)]	$103.42	964,832	$99,783,078
Transportation of Compressed Gas [(3)]	$0.91	964,832	$875,290
Carbon Dioxide Storage [(4)]	$5.44	964,832	$5,251,741
Total CCS System Cost	$109.77	N/A	**$105,910,109**

Notes:

1) Cost estimates for capture, transport, and storage vary greatly and are dependent on a variety of factors. Cost ranges in this table are based on recent available costs associated with current commercial-scale projects (DOE, 2010). These values assume capital costs have been fully amortized.

2) Estimates of capture and compression costs based on the CO_2 capture for new NGCC power plants converted to U.S. tons. (DOE, 2010 ,Page 33)

3) Estimates of transportation costs based on 100-kilometer pipeline transporting 5 million metric tons per year.

4) Estimates of storage costs derived from current commercial-scale projects.

Source:

DOE. (2010). Report of the Interagency Task Force on Carbon Capture and Storage. US Department of Energy, Interagency Task Force. August 2010. Accessed online at http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf.

4.4 REFORMER/PROCESS HEATERS

Step 1 – Identification of Potential Control Technologies

Energy Efficiency Design Technologies

As detailed below, there are several energy efficiency technologies that can be incorporated into the design of the methanol reformer and process heaters:

1. Air Preheat System: The combustion air is preheated prior to combustion, which reduces the required heat load for the reformer heater and increases thermal efficiency. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010).*

2. Efficient Burner Design: New burner designs have improved fuel mixing capabilities, which increase the burner efficiency and reduce GHG emissions.

(*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010.)*

3. Heat Recovery System: The flue gas from the combustion source is routed through a waste heat recovery system, which reduces the exit flue gas temperature and increases the thermal efficiency of the combustion source. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010).*

4. Increased Heat Transfer: Energy inefficiencies due to heat loss can be reduced by proper insulation and clean heat exchange surfaces. Maintenance plans can be developed in order to ensure the heat exchange surfaces are free from fouling. (*Energy Efficiency Improvement and Cost Savings for the Petrochemical Industry, July 2008).*

Best Operational Practices

As detailed below, there are several best practices that can be incorporated into the operation or design of the methanol reformer and process heaters:

5. Combustion Air Controls (Limitations on Excess Air/Oxygen): Oxygen monitors and intake air flow monitors can be used to optimize the fuel-to-air ratio and limit excess air, which results in increased combustion efficiency and decreased GHG emissions. Excess air should be limited to 2-3% oxygen. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010, Energy Efficiency Improvement and Cost Savings for the Petrochemical Industry, July 2008).*

6. Periodic Maintenance: Maintaining the combustion sources through a maintenance program results in increased thermal efficiency and energy savings. A maintenance plan can be developed that contains official documented procedures and a schedule for routine inspections and evaluations. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Improved Maintenance, November 2010).*

7. Fuel Selection: Firing natural gas or other gaseous fuels results in lower potential GHG emissions as demonstrated by Table C-1 in 40 CFR Part 98, Subpart C for "General Stationary Fuel Combustion Sources."

Step 2 – Elimination of Technically Infeasible Options

The seven process heaters in the MtG Unit (EPNs H-REGEN, H-RXH1-5, and H-HGT) are smaller heaters with maximum firing rates <100 MMBtu/hr. Therefore, installing combustion air preheat and waste heat recovery systems on these heaters would be technically infeasible.

For the Reformer (EPN B-01001), all options identified in Step 1 are considered technically feasible and therefore need to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Rank remaining control technologies based on control effectiveness

The control technologies specified in Step 1 above are all top-ranked control technologies for process heaters. The use of one technology does not preclude the use of any other control technology, and the combination of control technologies and practices will result in higher energy efficiency than any one. However, in order for completeness, the following table lists the technically feasible control technologies and their typical control efficiencies where they are available:

Table 4-2
Reformer/Process Heater BACT Control Efficiencies

Control Technology Description	Item No.	Control Technology Description	Typical Overall Control Eff. (%)	Source
Energy Efficiency Design	1.	Air Preheat System	10-15	GHG BACT for Refineries (Heat Recovery - Air Preheater)
Energy Efficiency Design	2.	Efficient Burner Design	N/A	GHG BACT for Refineries (Heat Recovery - Air Preheater)
Energy Efficiency Design	3.	Heat Recovery System	2-4	GHG BACT for Refineries (Recover Heat from Process Flue Gas)
Energy Efficiency Design	4.	Increased Heat Transfer	5-10	Energy Efficiency Improvement (Section 8)
Best Operational Practices	5.	Combustion Air Controls (Limits on Excess Air)	1-3	GHG BACT for Refineries (Combustion Air Controls - Limitations on Excess Air)
Best Operational Practices	6.	Periodic Maintenance	1-10	GHG BACT for Refineries (Improved Maintenance)
Best Operational Practices	7.	Fuel Selection	40	40 CFR Part 98, Subpart C, Table C-1, "Default Coemission Factors and High Heat Values for Various Types of Fuel"

Step 4 – Evaluate most effective controls in terms of economic, energy and environmental impacts and document results

All the aforementioned control technologies are considered economically reasonable since this will be a brand new site with the most up-to date technology. However, the use of an air preheat system could potentially increase emissions of thermal NO_X due to the increased temperature of combustion, which is an adverse environmental impact and potentially conflicts with BACT requirements for NO_X emissions. For sources to be equipped with SCR, NO_X emissions would not be impacted by an air preheat system, since the SCR system could be designed for the increase in NO_X emissions. The remaining potential control technologies listed will not result in any adverse environmental impacts.

Step 5 – Select BACT

Natgasoline proposes that BACT for the reformer is the combination of all the BACT options listed in Step 1. Natgasoline proposes that BACT for the seven smaller process heaters in the MtG Unit is the combination of all BACT options listed in Step 1, with the exception of combustion air preheat and waste heat recovery systems.

4.5 AUXILIARY BOILER

Step 1 – Identification of Potential Control Technologies

Energy Efficiency Design Technologies

As detailed below, there are several energy efficiency technologies that can be incorporated into the design of the auxiliary boiler:

1. Air Preheat System: The combustion air is preheated prior to combustion, which reduces the required heat load and increases thermal efficiency. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*

2. Efficient Burner Design: New burner designs have improved fuel mixing capabilities, which increase the burner efficiency and reduce GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*

3. Boiler Insulation: Insulating the outside surface area of the boiler reduces heat loss, which reduces the required heat load for the boiler and decreases potential GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*

4. Economizer: An economizer recovers waste from the boiler stack flue gas and preheats the boiler feed water, which reduces the required heat load for the boiler and decreases potential GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*

5. Condensate Return System: Hot condensate is returned to the boiler system to be used as boiler feed water, which reduces the required heat load for the boiler and decreases potential GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*

6. Refractory Material Selection: Use of refractory materials that provide the highest insulating capacity reduces heat loss and increases the energy efficiency of the boiler. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*

Best Operational Practices

As detailed below, there are several best practices that can be incorporated into the operation or design of the auxiliary boiler:

7. Combustion Air Controls (Limitations on Excess Air/Oxygen): Oxygen monitors and intake air flow monitors can be used to optimize the fuel-to-air ratio and limit excess air, which results in increased combustion efficiency and decreased GHG emissions. Excess air should be limited to approximately 10-15% or lower for a natural gas-fired boiler. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010, Energy Efficiency Improvement and Cost Savings for the Petrochemical Industry, July 2008).*

8. Periodic Maintenance: Maintaining the combustion sources through a maintenance program results in increased thermal efficiency and energy savings. A maintenance plan can be developed that contains official documented procedures and a schedule for routine inspections and evaluations. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Improved Maintenance, November 2010).*

9. Fuel Selection: Firing natural gas or other gaseous fuels results in lower potential GHG emissions, as demonstrated by Table C-1 in 40 CFR Part 98, Subpart C for "General Stationary Fuel Combustion Sources."

Step 2 – Elimination of Technically Infeasible Options

All options identified in Step 1 are considered technically feasible and therefore need to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Rank Remaining Control Technologies Based On Control Effectiveness

The control technologies specified in Step 1 above are all top-ranked control technologies for industrial boilers. The use of one technology does not preclude the use of any other control technology, and the combination of control technologies and practices will result in higher energy efficiency than any one. However, in order for completeness, the following table lists the technically feasible control technologies and their typical control efficiencies where they are available:

Table 4-3
Auxiliary Boiler BACT Control Efficiencies

Control Technology Description	Item No.	Control Technology Description	Typical Overall Control Eff. (%)	Source
Energy Efficiency Design	1.	Air Preheat System	10-15	GHG BACT for Refineries (Heat Recovery - Air Preheater)
Energy Efficiency Design	2.	Efficient Burner Design	N/A	GHG BACT for ICI Boilers (Replace/Upgrade Burners)
Energy Efficiency Design	3.	Boiler Insulation	6-26	Energy Efficiency Improvement (Section 7.1)
Energy Efficiency Design	4.	Economizer	2-4	GHG BACT for Refineries (Recover Heat from Process Flue Gas)
Energy Efficiency Design	5.	Condensate Return System	1-10% of steam energy use	GHG BACT for Refineries (Install Steam Condensate Return Lines)
Energy Efficiency Design	6.	Refractory Material Selection	N/A	GHG BACT for ICI Boilers (Refractory Material Selection)
Best Operational Practices	7.	Combustion Air Controls (Limits on Excess Air)	1-3	GHG BACT for Refineries (Combustion Air Controls - Limitations on Excess Air)
Best Operational Practices	8.	Periodic Maintenance	1-10	GHG BACT for Refineries (Improved Maintenance)
Best Operational Practices	9.	Fuel Selection	40	40 CFR Part 98, Subpart C, Table C-1, "Default Coemission Factors and High Heat Values for Various Types of Fuel"

Step 4 – Evaluate Most Effective Controls in Terms Of Economic, Energy, and Environmental Impacts and Document Results

All the aforementioned control technologies are considered economically reasonable since this will be a brand new site with the most up-to date technology. Additionally, the potential control technologies listed will not result in any adverse environmental impacts since this combustion source will be equipped with SCR.

Step 5 – Select BACT

Natgasoline proposes that BACT for the auxiliary boiler (EPN: B-14001) is the combination of all the BACT options listed in Step 1.

4.6 PLANT FLARE

Step 1 – Identification of Potential Control Technologies

1. Flare Gas Recovery: Installation and operation of a flare gas recovery system reduces GHG combustion emissions by routing flared gases back to the fuel gas system. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Flares, November 2010)*

2. Alternative Control Device Options: Installation of an alternative control device with a better control efficiency (e.g., thermal oxidizer) increases combustion efficiency, resulting in decreased methane emissions.

3. Proper Operation and Good Combustion Practices: Utilizing proper operation and combustion techniques (e.g., flare gas heat content) for the plant flare reduces combustion inefficiencies, resulting in decreased methane emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Flares, November 2010).*

4. Fuel Selection: Firing natural gas or other gaseous fuels results in lower potential GHG emissions as demonstrated by Table C-1 in 40 CFR Part 98, Subpart C for “General Stationary Fuel Combustion Sources.”

5. Minimize MSS Event Duration: Minimizing flaring events associated with MSS activities results in decreased GHG emissions from the plant flare.

Step 2 – Elimination of Technically Infeasible Options

The plant flare serves two primary purposes: as a VOC emissions control device, and also as a vital safety system for managing combustible gas and vapor materials generated during certain events, such as emergency and upset events. For BACT determination purposes, potential alternatives to a flare include a vapor combustor, thermal oxidizer, or flare gas recovery system. However, any other technology must serve both the VOC emission control and vital safety-related functions of a flare in order to be considered as a comparable BACT option.

A vapor combustor or thermal oxidizer would not be capable of safely managing the high vapor flow rates, high fuel heat input rates, and rapidly changing conditions that are inherent to emergency or upset events. Therefore, vapor combustors and thermal oxidizers are technically infeasible to serve as alternatives for the flare.

There are only two streams routed to the flare on a continuous basis (pilot gas and the compressor seal vents). A flare gas recovery system would be technically infeasible due to the very low volume of gas sent to the flare on a continuous basis. Additionally, the compressor seal vent gas composition is primarily nitrogen with only a small (<100 ppm) concentration of organics, and therefore it would not be practicable to route that stream back to process as fuel gas.

The following table lists the technically feasible control technologies and their typical control efficiencies where they are available (item Nos. 1 and 2 above were determined to be technically infeasible and are not shown in the below table):

Table 4-4: Plant Flare BACT Control Efficiencies

Item No.	Control Technology Description	Typical Overall Control Eff. (%)	Source
3.	Proper Flare Operation	N/A	GHG BACT for Refineries (Proper Flare Operation)
4.	Fuel Selection	40	40 CFR Part 98, Subpart C, Table C-1, "Default Coemission Factors and High Heat Values for Various Types of Fuel"
5.	Minimize Duration of MSS Events	N/A	N/A

Step 3 – Rank remaining control technologies based on control effectiveness

The above-mentioned control technologies identified in Step 1 (with the exception of the flare gas recovery system and alternative control devices) are all top-ranked control technologies for plant flares. The use of one technology does not preclude the use of any other control technology, and the combination of control technologies and practices will result in higher energy efficiency than any one alone.

Step 4 – Evaluate Most Effective Controls in Terms of Economic, Energy and Environmental Impacts and Document Results

All technically feasible control technologies listed are considered economically reasonable since this will be a brand new site with the most up-to-date technology. Additionally, the potential control technologies listed will not result in any adverse environmental impacts.

Step 5 – Select BACT

Natgasoline proposes that BACT for the plant flare (EPN: S-10001) is the combination of all the BACT options listed in Step 1, with the exception of the flare gas recovery system and alternative control device.

4.7 MARINE/RAILCAR/TRUCK LOADING/VAPOR COMBUSTOR

Step 1 – Identification of Potential Control Technologies

1. Alternative Control Device Options: Installation of a vapor recovery unit (VRU) would eliminate CO_2e emissions resulting from combustion.

2. Alternative Control Device Options: Installation of a carbon adsorption unit would eliminate CO_2e emissions resulting from combustion.

3. Proper Operation and Good Combustion Practices: Utilizing proper operation and combustion techniques (e.g., fuel-to-air ratio) for the vapor combustor reduces combustion inefficiencies, which results in decreased methane emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Flares, November 2010).*

4. Fuel Selection: Firing natural gas or other gaseous fuels results in lower potential GHG emissions as demonstrated by Table C-1 in 40 CFR Part 98, Subpart C for "General Stationary Fuel Combustion Sources."

Step 2 – Elimination of Technically Infeasible Options

A VRU or carbon adsorption system would not be able to manage the mass flow of vapors associated with loading gasoline into railcars, trucks, and barges considering the applicable air quality emission standards and the gasoline transfer rates necessary to support this GtG project. Therefore, the VRU and carbon adsorption alternatives are technically infeasible for purposes of minimizing emissions from these gasoline loading operations.

A vapor combustor (also called a direct-fired thermal oxidizer) uses combustion of the waste gas to control VOC emissions. A vapor combustor is proposed as BACT due to cost effectiveness and its ability to handle fluctuations in waste gas composition.

All other identified control technologies (item Nos. 3 and 4 listed above) are technically feasible and therefore are considered in Step 3 below.

Step 3 – Rank remaining control technologies based on control effectiveness

The control technologies identified in Step 1 and not eliminated in Step 2 are top-ranked control technologies for vapor combustors/thermal oxidizers. The use of one technology does not preclude the use of any other control technology, and the combination of control technologies and practices will result in higher energy efficiency than any one alone. However, in order for completeness, the following table lists the technically feasible control technologies and their typical control efficiencies where they are available (item Nos. 1 and 2 were eliminated in Step 2):

Table 4-5
Vapor Combustor BACT Control Efficiencies

Item No.	Control Technology Description	Typical Overall Control Eff. (%)	Source
3.	Proper Operation/Good Combustion Techniques	N/A	GHG BACT for ICI Boilers
4.	Fuel Selection	40	40 CFR Part 98, Subpart C, Table C-1, "Default Coemission Factors and High Heat Values for Various Types of Fuel"

Step 4 – Evaluate most effective controls in terms of economic, energy, and environmental impacts and document results

All the aforementioned control technologies listed (except those ruled out in Step 2) are considered economically reasonable since this will be a brand new site with the most up-to-date technology. Additionally, the potential control technologies listed will not result in any adverse environmental impacts.

Step 5 – Select BACT

Natgasoline proposes that BACT for loading is a vapor combustor (EPN: VCU-1). GHG emissions from the vapor combustor will be minimized using the combination of BACT item Nos. 3 and 4 listed in Step 1.

4.8 CATALYST REGENERATION VENT (EPN V-CATREGEN)

Coke buildup on the catalyst in the MtG reaction process is an unavoidable part of the MtG reaction process, and the coke must be removed in accordance with manufacturer specifications to ensure the catalyst works properly and does not cause unnecessary process shutdowns.

Step 1 – Identification of Potential Control Technologies

<u>Proper Operating Techniques</u>: Utilizing proper operating techniques (e.g., minimizing catalyst coke deposits and the number of catalyst regeneration per year without negatively impacting the overall energy efficiency of the MtG process) results in decreased GHG emissions from MtG catalyst regeneration.

Step 2 – Elimination of Technically Infeasible Options

The option identified in Step 1 is considered technically feasible and therefore needs to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Rank Remaining Control Technologies Based on Control Effectiveness

The catalyst regeneration duration time is approximately 15 hours and occurs 110 times per year week for a total of 1,681 hours/year. Emissions of CO_2e from this vent are insignificant (5,446 ton/year); therefore, this is BACT for the catalyst regeneration vent.

Step 4 – Evaluate Most Effective Controls in Terms of Economic, Energy and Environmental Impacts and Document Results

The aforementioned control technology is considered economically reasonable since no add-on control is necessary.

Step 5 – Select BACT

Natgasoline proposes that BACT for the catalyst regeneration vent (EPN: V-CATREGEN) is the option listed in Step 1.

4.9 PROCESS CONDENSATE STRIPPER AND DEGASSER VENTS (EPNS D-01501 AND D-50001)

Step 1 – Identification of Potential Control Technologies

Recovery of CO_2 from Vent Streams: Removing the CO_2 from the process condensate streams prior to the process steam condensate stripper and degasser (EPNs D-01501 and D-50001) results in decreased GHG emissions.

Step 2 – Elimination of Technically Infeasible Options

The concentration of GHG pollutants in the vent streams are so dilute (1% by weight) that it would be technically infeasible to reduce the concentration to a lower amount.

Step 3 – Rank Remaining Control Technologies Based on Control Effectiveness

There is no additional control technology to evaluate for these emissions sources.

Step 4 – Evaluate Most Effective Controls in Terms of Economic, Energy and Environmental Impacts and Document Results

There is no additional control technology to evaluate for these emissions sources.

Step 5 – Select BACT

Natgasoline proposes that BACT for the process steam condensate stripper and degasser vents is routing the vents to the atmosphere.

4.10 PROCESS FUGITIVES

Step 1 – Identification of Potential Control Technologies

1. Installation of Leakless Technology: Installing leakless technology components would eliminate GHG emissions from fugitive components.
2. Implementation of LDAR Program: Utilizing a vapor analyzer or other organic vapor sensing technology to monitor fugitive components for leaks on a set basis results in

decreased emissions of GHG pollutants. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Fuel Gas System, November 2010).*

3. Alternative Monitoring using Infrared Technology: Similar to implementation of an LDAR program, the use of sensitive infrared (IR) camera technology to detect leaks of hydrocarbons results in a decrease in GHG emissions.

4. Compressor Selection: Utilizing dry-seal compressors (rather than wet-seal) and rod packing for reciprocating compressors results in decreased emissions of GHG pollutants from compressors. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Fuel Gas System, November 2010).*

Step 2 – Technical Feasibility

All options identified in Step 1 are considered technically feasible and therefore need to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Control Effectiveness

Leakless Technologies

Leakless technology would result in a control effectiveness of approximately 100%. This is the most effective of the available control technologies.

LDAR Programs

LDAR programs are generally designed to reduce VOC emissions from leaking components. Equipment in natural gas service or fuel gas service where methane is one of the primary constituents of the stream is generally not monitored under existing LDAR programs since methane is not a VOC. There is no data for the control effectiveness of LDAR programs on components in GHG service; therefore, the same control efficiencies under the TCEQ VOC monitoring program are used for components in methane service.

The TCEQ's 28LAER program is the most stringent of their LDAR monitoring programs. The 28LAER program achieves a control efficiency of 97% for valves, 95% for compressors, and 75% for connectors in VOC service monitored under the program. This program requires quarterly monitoring of valves and compressors and annual monitoring of connectors. Additionally, leak repair is required to be performed using directed maintenance, which requires an approved gas analyzer to be used throughout the maintenance and repair process.

The TCEQ's 28VHP LDAR program is a less stringent program than 28LAER, but it is considered BACT for fugitive components in VOC service for this project. The 28VHP program achieves a control efficiency of 97% for valves, 85% for compressors, and 30% for connectors in VOC service monitored under the program. This program does not require directed maintenance.

Alternative Monitoring Program

Leak detection using IR camera technology is considered by the EPA to be partial alternative monitoring technology to Method 21 (gas analyzer), meaning that the programs are equivalent if, in addition to the remote sensor monitoring, components are also monitored using Method 21 at least annually. Therefore, the control effectiveness for remote sensing technology alone is assumed to be 75%, based on TCEQ's 28LAER program for connector monitoring.

Compressor Design

Use of dry-seal compressors and rod packing (for any reciprocating compressors) are considered effective methods of controlling GHG emissions from compressors; however, there is no data available to support exact control efficiencies.

Step 4 – Economic, Energy, and Environmental Impacts

Leakless Technologies

Leakless technology, while the most effective of the control technologies, has not been adopted as BACT or Lowest Achievable Emission Rate (LAER) for any projects with GHG emissions from fugitive components. Additionally, leakless technology is not required to control fugitive emissions of toxic or other hazardous air pollutants (HAPs) under Federal rules. Therefore, it is not reasonable to install leakless components for the control of methane, which has no known hazardous impacts.

LDAR Programs

Two different LDAR monitoring programs were analyzed for control effectiveness: TCEQ's 28LAER and 28VHP. Uncontrolled GHG emissions from fugitive components contribute less than 1% to the total GHG emissions from the project (<1,100 tpy of CO_{2e}). Based on economic reasonableness, Natgasoline proposes that BACT for fugitive emission is 28VHP, which is the same program that will be used for components in VOC service that require monitoring.

Implementing 28VHP will reduce the uncontrolled GHG emissions from fugitive components by 70% to less than 320 tpy. The cost of performing directed maintenance and monitoring connectors annually (as required by 28LAER) would be unreasonable to only achieve an additional 11% reduction in fugitive emissions. Following is a brief cost analysis associated with annual monitoring of connectors. The analysis does not take into account any additional costs associated with directed maintenance, which would be entirely variable based on the number of detected leaks and therefore would be difficult to estimate.

- Estimated number of connectors in methane service = 1,808.
- CO_2e emissions associated with connectors under proposed 28VHP LDAR program = 318 tpy.
- CO_2e emissions associated with connectors under 28LAER LDAR program = 200 tpy (i.e., a 118 tpy reduction as compared to implementing 28VHP).
- Additional cost associated with annual LAER connector monitoring = 0.25 hours/connector * $50/hour for LDAR technician time (conservative estimate) * 1,808 connectors/year = **$22,600 / year.**
- Cost per ton of CO_2e reduced = $22,600/year / 118 tons of CO_2e/year = **$191/tpy CO_2e.**

Compressor Design

All the aforementioned control technologies listed are considered economically reasonable. Additionally, the potential control technologies listed will not result in any adverse environmental impacts.

Step 5 – Selection of BACT

The proposed GtG plant will implement TCEQ's 28VHP program for equipment in VOC service. Additionally, the proposed GtG plant will monitor equipment in natural gas or fuel gas service under the 28VHP program. Natgasoline will also install compressors that meet the seal and rod packing requirements as BACT for compressors.

4.11 EMERGENCY GENERATOR AND FIREWATER PUMP ENGINES (EPNS H-EMG AND H-FWP1/2)

Step 1 – Identification of Potential Control Technologies

As detailed below, there are several energy efficiency technologies and best practices that can be incorporated into the design and operation of the emergency generator and firewater pump engines:

1. Vendor-Certified Tier 4 and Clean Burn Engine: The U.S. EPA has set stringent emission standards for non-road diesel engines in accordance with 40 CFR Part 60, Subpart IIII. Compliance with these standards will result in lower potential GHG emissions.

2. Fuel Selection: Firing natural gas or other gaseous fuels results in lower potential GHG emissions as demonstrated by Table C-1 in 40 CFR Part 98, Subpart C for "General Stationary Fuel Combustion Sources."

3. Operation Restriction: Dedication to emergency service will limit the total hours of operation as well as GHG emissions. Operating hours can be monitored with the use of a run-time meter in conjunction with administrative controls to reduce engine use.

Step 2 – Elimination of Technically Infeasible Options

During emergency conditions, non-volatile fuel (such as diesel or other heavy oils) is required to be used and readily available. Natural gas or other gaseous fuels would not be available during certain emergency events; therefore, these lower carbon fuels are not technically feasible options for emergency engines. All remaining options identified in Step 1 are considered technically feasible and therefore need to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Rank remaining control technologies based on control effectiveness

The control technologies specified in Step 1 above are all top-ranked control technologies for emergency engines, with the exception of low carbon fuel selection. The use of one technology or practice does not preclude the use of any other control technology or practice, and the combination of control technologies and practices will result in higher energy efficiency than any one.

Step 4 – Evaluate most effective controls in terms of economic, energy and environmental impacts and document results

Except for low carbon fuel selection, all the aforementioned control technologies are considered economically reasonable. These listed potential control technologies will not result in any adverse environmental impacts.

Step 5 – Select BACT

Natgasoline proposes that BACT for the emergency generator engine and the firewater pump engines is the combination of all the BACT options listed in Step 1, with the exception of low carbon fuel selection.

APPENDIX A
ADMINISTRATIVE APPLICATION FORM

Administrative Information

I. Applicant Information		
A. Company or Other Legal Name: **Natgasoline, LLC**		
B. Company Official Contact Name: **Kevin Struve**		
Title: **Manager**		
Mailing Address: **P.O. Box 1647**		
City: **Nederland**	State: **Texas**	ZIP Code: **77627**
Telephone No.: **409-723-1900**	Fax No.: **TBD**	E-mail Address: **kstruve@orascomci.co.uk**
C. Technical Contact Name: **Same as above**		
Title:		
Company Name:		
Mailing Address:		
City:	State:	ZIP Code:
Telephone No.:	Fax No.:	E-mail Address:
D. Site Name: **Beaumont Gas-to-Gasoline Plant**		
E. Area Name/Type of Facility: **Beaumont Gas-to-Gasoline Plant**	☒ 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: **October 2013**		
Projected Start of Operation Date: **December 2014**		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: **Approximately 0.3 miles due north of the interchange between TX-347/North Twin City Highway and U.S. 287 S/US-69 S/US-96 N at the intersection of Highway 380 Access Road and Sulphur Plant Road.**		
City/Town: **Beaumont**	County: **Jefferson**	ZIP Code: **77705**
I. TCEQ Customer Reference Number (CN): **TBD**		
J. TCEQ Regulated Entity Number (RN): **TBD**		

APPENDIX B
TABLE 1(A)

Texas Commission on Environmental Quality
Table 1(a) Emission Point Summary
Natgasoline, LLC - New GtG Plant

Date: February 2013	**Permit No.:** TBD	**Regulated Entity No.:** TBD
Area Name:		**Customer Reference No.:** TBD

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

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate		4. UTM Coordinates of Emissions Point			Source							
									5. Building Height (Ft.)	6. Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
B-01001	B-01001	Reformer	CO_2	172,850.37	653,515.61	TBD	TBD	TBD	--	114.8	11.15	TBD	424.4	--	--	--
			CH_4	3.11	11.76											
			N_2O	0.31	1.18											
			CO_2e	173,012.14	654,127.22											
B-14001	B-14001	Auxiliary Boiler	CO_2	100,962.70	340,213.90	TBD	TBD	TBD	--	114.8	11.15	TBD	356.0	--	--	--
			CH_4	1.90	6.42											
			N_2O	0.19	0.64											
			CO_2e	101,061.72	340,547.57											
H-REGEN	H-REGEN	Regeneration Heater	CO_2	4,737.06	11,575.38	TBD	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.09	0.22											
			N_2O	0.01	0.02											
			CO_2e	4,741.71	11,586.74											
H-RX1 H-RX2 H-RX3 H-RX4 H-RX5	H-RX1 H-RX2 H-RX3 H-RX4 H-RX5	Reactors Heaters	CO_2	14,204.46	62,215.52	TBD	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.27	1.17											
			N_2O	0.03	0.12											
			CO_2e	14,218.39	62,276.53											
H-HGT	H-HGT	Heavy Gasoline Heater Treater	CO_2	886.47	3,494.46	TBD	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.02	0.07											
			N_2O	<0.01	0.07											
			CO_2e	887.34	3,497.88											
S-10001	S-10001	MeOH Flare Pilot & Normal Operation	CO_2	586.91	2,570.66	TBD	TBD	TBD	--	256	7	TBD	TBD	--	--	--
			CH_4	1.50	6.54											
			N_2O	<0.01	<0.01											
			CO_2e	618.66	2,709.21											
TBD	F-10001	MeOH Flare MSS Vents	CO_2	711,987.22	11,390.09	TBD	TBD	TBD	--	256	7	TBD	TBD	--	--	--
			CH_4	160.45	2.57											
			N_2O	1.19	0.02											
			CO_2e	715,726.13	11,449.84											

Texas Commission on Environmental Quality
Table 1(a) Emission Point Summary
Natgasoline, LLC - New GtG Plant

Date: February 2013	**Permit No.:** TBD	**Regulated Entity No.:** TBD
Area Name:		**Customer Reference No.:** TBD

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

AIR CONTAMINANT DATA						**EMISSION POINT DISCHARGE PARAMETERS**										
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**		**4. UTM Coordinates of Emissions Point**			**Source**							
									5. Building Height (Ft.)	**6. Height Above Ground (Ft.)**	**7. Stack Exit Data**			**8. Fugitives**		
(A) EPN	**(B) FIN**	**(C) Name**		**(A) Pound Per Hour**	**(B) TPY**	**Zone**	**East (Meters)**	**North (Meters)**			**(A) Diameter (Ft.)**	**(B) Velocity (FPS)**	**(C) Temperature (°F)**	**(A) Length (Ft.)**	**(B) Width (Ft.)**	**(C) Axis Degrees**
VCU-1	VCU-1	MeOH/MtG VCU	CO_2	6,984.13	2,688.63	TBD	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.13	0.05											
			N_2O	0.01	0.01											
			CO_2e	6,992.22	2,691.75											
FUG-MEOH	FUG-MEOH	MeOH Fugitives	CO_2	-	-	TBD	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	2.10	9.18											
			N_2O	-	-											
			CO_2e	44.03	192.86											
FUG-MTG	FUG-MTG	MtG Fugitives	CO_2	-	-	TBD	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	1.36	5.97											
			N_2O	-	-											
			CO_2e	28.63	125.42											
D-01501	D-01501	Process Condensate Stripper Vent	CO_2	260.01	1,138.87	TBD	TBD	TBD	--	TBD	--	--	--	TBD	TBD	TBD
			CH_4	1.00	4.37											
			N_2O	-	-											
			CO_2e	280.97	1,230.64											
D-05001	D-05001	Process Condensate Degasser Vent	CO_2	184.13	806.48	TBD	TBD	TBD	--	TBD	--	--	--	TBD	TBD	TBD
			CH_4	-	-											
			N_2O	-	-											
			CO_2e	184.13	806.48											
V-CATREGEN	V-CATREGEN	Catalyst Regeneration Vent	CO_2	6,479.25	5,445.81	TBD	TBD	TBD	--	TBD	--	--	--	TBD	TBD	TBD
			CH_4	-	-											
			N_2O	-	-											
			CO_2e	6,479.25	5,445.81											
H-EMG	H-EMG	Emergency Generator	CO_2	2,782.18	139.11	TBD	TBD	TBD	--	TBD	--	--	--	TBD	TBD	TBD
			CH_4	0.11	0.01											
			N_2O	0.02	<0.01											
			CO_2e	2,791.54	139.58											

Texas Commission on Environmental Quality
Table 1(a) Emission Point Summary
Natgasoline, LLC - New GtG Plant

Date: February 2013	**Permit No.:** TBD	**Regulated Entity No.:**	TBD
Area Name:		**Customer Reference No.:**	TBD

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

AIR CONTAMINANT DATA						**EMISSION POINT DISCHARGE PARAMETERS**										
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**		**4. UTM Coordinates of Emissions Point**			**Source**							
									5. Building Height (Ft.)	**6. Height Above Ground (Ft.)**	**7. Stack Exit Data**			**8. Fugitives**		
(A) EPN	**(B) FIN**	**(C) Name**		**(A) Pound Per Hour**	**(B) TPY**	**Zone**	**East (Meters)**	**North (Meters)**			**(A) Diameter (Ft.)**	**(B) Velocity (FPS)**	**(C) Temperature (°F)**	**(A) Length (Ft.)**	**(B) Width (Ft.)**	**(C) Axis Degrees**
H-FWP1 H-FWP2	H-FWP1 H-FWP2	Firewater Pump Engines	CO_2	2,782.18	139.11	TBD	TBD	TBD	--	TBD	--	--	--	TBD	TBD	TBD
			CH_4	0.11	0.01											
			N_2O	0.02	<0.01											
			CO_2e	2,791.54	139.58											

EPN = EMISSION POINT NUMBER

FIN = FACILITY IDENTIFICATION NUMBER

This form designed to correspond with TCEQ - 10153 (Revised 04/08) Table 1(a).

APPENDIX C
PSD EVALUATION FORMS

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: **TBD**	Application Submittal Date: **TBD**
Company: **Natgasoline, LLC**	
RN: **TBD**	Facility Location: **Approximately 0.3 miles due north of the interchange between TX-347/North Twin City Highway and U.S. 287 S/US-69 S/US-96 N at the intersection of Highway 380 Access Road and Sulphur Plant Road.**
City: **Beaumont**	County: **Jefferson**
Permit Unit I.D.: **NA**	Permit Name: **TBD**
Permit Activity: ☒ New Source ☐ Modification	
Project or Process Description: **Natgasoline LLC is proposing to construct a new gasoline production plant in Nederland, Texas. The new gasoline production plant will synthesize motor-grade gasoline from methanol using a natural gas feedstock. The new plant will be authorized under a new NSR and PSD permit.**	

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS						
	Ozone		CO	PM$_{10}$	NO$_X$	SO$_2$	Other[1] CO$_2$e
	VOC	NO$_X$					
Nonattainment? (yes or no)							**No**
Existing site PTE (tpy)?							**NA**
Proposed project emission increases (tpy from 2F)[3]							**1,096,967**
Is the existing site a major source? [2]If not, is the project a major source by itself? (yes or no)							**NA**
If site is major, is project increase significant?							**Yes**
If netting required, estimated start of construction?	**October 2013**						
Five years prior to start of construction	**October 2008**						contemporaneous
Estimated start of operation	**December 2014**						period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)							**NA**
FNSR APPLICABLE? (yes or no)							**Yes**

[1] Other PSD pollutants.

[2] Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR § 51.166(b)(1).

[3] Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR § 51.166(b)(23).

TABLE 2F

PROJECT EMISSION INCREASE

Pollutant[1]:	CO_2e	**Permit:**	TBD
Baseline Period:	**Not applicable (proposed new stationary source)**		

	Affected or Modified Facilities[2]		Permit No.	Actual Emissions[3]	A	B	Projected Actual Emissions	Difference (B-A)[6]	Correction[7]	Project Increase[8]
	FIN	**EPN**			**Baseline Emissions[4]**	**Proposed Emissions[5]**				
1	B-01001	B-01001	TBD	-	-	654,127.22	-	654,127.22		654,127.22
2	B-14001	B-14001	TBD	-	-	340,547.57	-	340,547.57		340,547.57
3	H-REGEN	H-REGEN	TBD	-	-	11,586.74	-	11,586.74		11,586.74
4	H-RX1 H-RX2 H-RX3 H-RX4 H-RX5	H-RX1 H-RX2 H-RX3 H-RX4 H-RX5	TBD	-	-	62,276.53	-	62,276.53		62,276.53
5	H-HGT	H-HGT	TBD	-	-	3,497.88	-	3,497.88		3,497.88
6	S-10001	S-10001	TBD	-	-	2,709.21	-	2,709.21		2,709.21
7	F-10001	TBD	TBD	-	-	11,449.84	-	11,449.84		11,449.84
8	VCU-1	VCU-1	TBD	-	-	2,691.75	-	2,691.75		2,691.75
9	FUG-MEOH	FUG-MEOH	TBD	-	-	192.86	-	192.86		192.86
10	FUG-MTG	FUG-MTG	TBD	-	-	125.42	-	125.42		125.42
11	D-01501	D-01501	TBD	-	-	1,230.64	-	1,230.64		1,230.64
12	D-05001	D-05001	TBD	-	-	806.48	-	806.48		806.48
13	V-CATREGEN	V-CATREGEN	TBD	-	-	5,445.81	-	5,445.81		5,445.81
14	H-EMG	H-EMG	TBD	-	-	139.58	-	139.58		139.58
14	H-FWP1 H-FWP2	H-FWP1 H-FWP2	TBD	-	-	139.58	-	139.58		139.58
								Page Subtotal[9]	0.00	1,096,967.09

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

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

APPENDIX D
EMISSION CALCULATIONS

Table D-1
Summary of Potential to Emit
Natgasoline, LLC - New GtG Plant

A. Annual Potential to Emit (PTE) Summary

Emission Source Description	Potential Annual Emissions (tons/year) (1)				Reference Table
	CO_2	CH_4	N_2O	CO_2e	
Methanol Reformer	653,515.61	11.76	1.18	654,127.22	D-2
Methanol Auxiliary Burner	340,213.90	6.42	0.64	340,547.57	D-2
MtG Regeneration Heater	11,575.38	0.22	0.02	11,586.74	D-2
MtG Reactors Heaters	62,215.52	1.17	0.12	62,276.53	D-2
MtG Heavy Gasoline Heater Treater	3,494.46	0.07	0.07	3,497.88	D-2
Methanol Flare Pilot & Normal Operation	2,570.66	6.54	<0.01	2,709.21	D-3
Methanol Flare MSS Vents	11,390.09	2.57	0.02	11,449.84	D-4
Methanol/MtG VCU	2,688.63	0.05	0.01	2,691.75	D-8
Methanol Fugitives	-	9.18	-	192.86	D-9
MtG Fugitives	-	5.97	-	125.42	D-10
Process Condensate Stripper Vent	1,138.87	4.37	-	1,230.64	D-11
Process Condensate Degasser Vent	806.48	-	-	806.48	D-11
Catalyst Regeneration Vent	5,445.81	-	-	5,445.81	D-11
Emergency Generator	139.11	0.01	<0.01	139.58	D-12
Firewater Pump Engines	139.11	0.01	<0.01	139.58	D-12
Total Proposed PTE	**1,095,333.62**	**48.33**	**2.05**	**1,096,967.09**	Totals
Major Source Threshold	NA	NA	NA	100,000	
Triggers Major Source Permitting?	**NA**	**NA**	**NA**	**Yes**	

Notes:

1) All sources associated with this project are new sources; therefore, baseline emissions are zero and the total emissions increases for purposes of federal applicability are equal to the PTEs. See TCEQ PSD Tables 2F and 3F for additional details.

Table D-1
Summary of Potential to Emit
Natgasoline, LLC - New GtG Plant

B. Hourly Potential To Emit (PTE) Summary

Emission Source Description	Potential Hourly Emissions (lb/hour)				Reference Table
	CO_2	CH_4	N_2O	CO_2e	
Methanol Reformer	172,850.37	3.11	0.31	173,012.14	D-2
Methanol Auxiliary Burner	100,962.70	1.90	0.19	101,061.72	D-2
MtG Regeneration Heater	4,737.06	0.09	0.01	4,741.71	D-2
MtG Reactors Heaters	14,204.46	0.27	0.03	14,218.39	D-2
MtG Heavy Gasoline Heater Treater	886.47	0.02	<0.01	887.34	D-2
Methanol Flare Pilot & Normal Operation	586.91	1.50	<0.01	618.66	D-3
Methanol Flare MSS Vents	711,987.22	160.45	1.19	715,726.13	D-4
Methanol/MtG VCU	6,984.13	0.13	0.01	6,992.22	D-8
Methanol Fugitives	-	2.10	-	44.03	D-9
MtG Fugitives	-	1.36	-	28.63	D-10
Process Condensate Stripper Vent	260.01	1.00	-	280.97	D-11
Process Condensate Degasser Vent	184.13	-	-	184.13	D-11
Catalyst Regeneration Vent	6,479.25	-	-	6,479.25	D-11
Emergency Generator	2,782.18	0.11	0.02	2,791.54	D-12
Firewater Pump Engines	2,782.18	0.11	0.02	2,791.54	D-12
Total Proposed PTE	**1,025,687.05**	**172.15**	**1.79**	**1,029,858.40**	Totals

Table D-2
Potential Greenhouse Gas Emissions from Combustion Sources
Natgasoline, LLC - New GtG Plant

A. Emission Factors and Global Warming Potential (GWP) Equivalency Factors

CO_2(1)	53.02	kg CO_2/MMBtu	&	**CO_2**(2)	=	1 ton of CO2 equivalent
CH_4(1)	0.001	kg CH_4/MMBtu	&	**CH_4**(2)	=	21 tons of CO2 equivalent
N_2O(1)	0.0001	kg N_2O/MMBtu	&	**N_2O**(2)	=	310 tons of CO2 equivalent

B. Emission Calculations

Emission Source	**Design Firing Rate**		**CO_2 Emissions**		**CH_4 Emissions**		**N_2O Emissions**		**CO_2e Emissions** (5)	
	Max.	**Aver.**	**Hourly**	**Annual**	**Hourly**	**Annual**	**Hourly**	**Annual**	**Hourly**	**Annual**
	MMBtu/hr	**MMBtu/hr**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Reformer (MeOH) (6)	1,411	1,218	172,850	653,516	3.11	11.76	0.31	1.18	173,012	654,127
Auxiliary Boiler (MeOH)	864	664	100,963	340,214	1.90	6.42	0.19	0.64	101,062	340,548
Regeneration Heater (MtG)	41	23	4,737	11,575	0.09	0.22	0.01	0.02	4,742	11,587
Reactors Heaters (MtG) (7)	122	122	14,204	62,216	0.27	1.17	0.03	0.12	14,218	62,277
Heavy Gasoline Heater Treater (MtG)	8	7	886	3,494	0.02	0.07	0.00	0.01	887	3,498
Sub total MeOH Unit Sources			273,813	993,730	5.02	18.18	0.50	1.82	274,074	994,675
Sub total MtG Unit Sources			19,828	77,285	0.37	1.46	0.04	0.15	19,847	77,361
Totals			**293,641**	**1,071,015**	**5.39**	**19.64**	**0.54**	**1.96**	**293,921**	**1,072,036**

Notes:

(1) Emission factors are based on 40 CFR Part 98 Subpart C, Table C-1 and Table C-2 for natural gas.

(2) Global warming potential factors are based on 40 CFR Part 98 Subpart A, Table A-1.

(3) Hourly emissions are based on the emission factor * max. hourly firing rate * 2.204 lb/kg.

(4) Annual emissions are based on the emission factor * aver. hourly firing rate (normal) * 2.204 lb/kg * 8,760 hours/year / 2000 lb/ton

(5) CO_2e emissions are based on the sum of the CO_2, CH_4, and N_2O emissions times their respective GWP factors.

(6) CO2 emissions for the Reformer are based on Reformer-specific fuel carbon content of 0.4661 and a molecular weight of 16 lb/lb-mole.

(7) The design firing rate for all five heaters is based on the individual firing rate * 5.

Table D-2
Potential Greenhouse Gas Emissions from Combustion Sources
Natgasoline, LLC - New GtG Plant

C. Supplemental Table for Reformer Fuel Carbon Content Calculation

Constituent	Volume %	MW	Mass %	No. of Carbons	Carbon Content
H2	40.49%	2	4.96%	-	-
CH4	38.15%	16	37.42%	1	0.2809
C2H6	1.34%	30	2.46%	2	0.0197
C3H8	0.85%	44	2.29%	3	0.0188
C4H10	0.33%	58	1.17%	4	0.0097
C5H12	0.09%	72	0.40%	5	0.0033
C6H14	<0.01	86	<0.01	6	0.0049
CH3OH	0.02	74	0.09	1	0.0138
N2	<0.01	28	0.02	-	-
CO2	0.14	44	0.38	1	0.1025
CO	0.02	28	0.03	1	0.0125
H2S	<0.01	34.08	<0.01	-	-
H2O	<0.01	18.02	<0.01	-	-
Total	99.88	-	100.00		**0.4661**

Table D-3
Flare - Pilot and Normal Operation Emission Calculations
Natgasoline, LLC - New GtG Plant

A. Pilot Gas Emissions

Parameter Name & Variable		Value & Units	Basis/Calculations/Notes
1. General Values and Calculations			
Hourly Flow Rate	F_H	1,045 scf/hr	Estimated Max Hourly Flow
Annual Flow Rate	F_A	9,154,200 scf/yr	Estimated Average Annual Flare Flow
Heat Content	H	1,020 Btu/scf	Typical Heat Content of Natural Gas
2. CO_2 Emission Rate Calculations			
CO_2 Emission Factor	F_{CO2}	120,000 lb/MMscf	AP-42, Table 1.4-2
CO_2 Hourly Emission Rate	-	**125.40 lb/hr**	= (F_H / 1,000,000 scf/MMscf) x F_{CO2}
CO_2 Annual Emission Rate	-	**549.25 tpy**	= (F_A / 1,000,000 scf/MMscf) x F_{CO2} / 2,000 lb/ton
3. CH_4 Emission Rate Calculations			
CH_4 Emission Factor	F_{CH4}	0.00220 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
CH_4 Hourly Emission Rate	ER_{CH4}	**<0.01 lb/hr**	= F_H x (H / 1,000,000 Btu/MMBtu) x F_{CH4}
CH_4 Annual Emission Rate	ER_{CH4}	**<0.01 tpy**	= F_A x (H / 1,000,000 Btu/MMBtu) x F_{CH4} / 2,000 lb/ton
Hourly Global Warming Potential	GWP_{CH4}	0.05 lb/hr	= ER_{CH4} * 21 CO_2e
Annual Global Warming Potential	GWP_{CH4}	<0.01 tpy	= ER_{CH4} * 21 CO_2e
4. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	0.00022 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
N_2O Hourly Emission Rate	ER_{N2O}	**<0.01 lb/hr**	= F_H x (H / 1,000,000 Btu/MMBtu) x F_{N2O}
N_2O Annual Emission Rate	ER_{N2O}	**<0.01 tpy**	= F_A x (H / 1,000,000 Btu/MMBtu) x F_{N2O} / 2,000 lb/ton
Hourly Global Warming Potential	GWP_{N2O}	0.07 lb/hr	= ER_{N2O} * 310 CO_2e
Annual Global Warming Potential	GWP_{N2O}	<0.01 tpy	= ER_{N2O} * 310 CO_2e
5. Total CO_2e Emission Rates			
Hourly Global Warming Potential	-	**125.52 lb/hr**	= ER_{CO2} + GWP_{CH4} + GWP_{N2O}
Annual Global Warming Potential	-	**549.25 tpy**	= ER_{CO2} + GWP_{CH4} + GWP_{N2O}

Table D-3
Flare - Pilot and Normal Operation Emission Calculations
Natgasoline, LLC - New GtG Plant

B. Compressor Seal Vent Flare Emissions (plus supplemental natural gas)

Parameter Name & Variable		Value & Units		Basis/Calculation/Notes
1. General Values and Calculations				
Hourly Vapor Mass to Flare	M_H	1,201 lb/hr		Based on Estimated Flow to Flare
Annual Vapor Mass to Flare	M_A	10,520,689 lb/year		Based on M_H * 8760 hrs/year
Hourly Vapor Volume to Flare	Q_H	18,630.32 scf/hr		Based on Estimated Flow to Flare
Annual Vapor Volume to Flare	Q_A	163 MMscf/yr		Based on Q_H * 8760 hrs/year
Max. Hourly Vapor Heat Input to Flare	H_H	4 MMBtu/hr		Based on Typical Stream Composition and Flow
Annual Vapor Heat Input to Flare	H_A	33,612 MMBtu/yr		Based on Typical Stream Composition and Flow
2. Combined Gas Composition		Volume %	MW	
N_2 Volume Percent & Molecular Weight		76	28.01	Based on Typical Stream Composition
H_2 Volume Percent & Molecular Weight		4	2.02	Based on Typical Stream Composition
CH_3OH Volume Percent & Molecular Weight		0	32.04	Based on Typical Stream Composition
C_4H_{10} Volume Percent & Molecular Weight		1	58.12	Based on Typical Stream Composition
CH_4 Volume Percent & Molecular Weight		19	16.04	Based on Typical Stream Composition
2. CO_2 Emission Rate Calculations				
Total Molecular Weight	MW_T	24.84 lb/lb-mol		Based on Typical Stream Composition
Carbon Content	CC	0.10		= Σ (No. of Carbons * 12/MW_i * MW_i/MW_T)
CO_2 Hourly Emission Rate	ER_{CO2H}	**462 lb/hr**		= 44/12 * Q_H * CC * MW_T / 385 scf/lb-mol
CO_2 Annual Emission Rate	ER_{CO2A}	**2,021 tpy**		= 44/12 * Q_A * CC * MW_T / 385 scf/lb-mol / 2,000 lb/ton
3. CH_4 Emission Rate Calculations				
CH_4 Weight Percent	W_{CH4}	12.44 %		Assumes natural gas component is 90% methane by weight
Flare DRE for CH_4	%	99 %		TCEQ Flare Guidance Document (October 2000)
CH_4 Hourly Emission Rate	ER_{CH4H}	**1.49 lb/hr**		= W_{CH4} * M_H * (100%-DRE)
CH_4 Annual Emission Rate	ER_{CH4A}	**6.54 tpy**		= W_{CH4} * M_A * (100%-DRE) / 2000 lb/ton
Hourly Global Warming Potential	GWP_{CH4H}	31 lb/hr		= ER_{CH4H} * 21 CO_2e
Annual Global Warming Potential	GWP_{CH4A}	137 tpy		= ER_{CH4A} * 21 CO_2e

Table D-3
Flare - Pilot and Normal Operation Emission Calculations
Natgasoline, LLC - New GtG Plant

4. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	0.00022 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
N_2O Hourly Emission Rate	ER_{N2OH}	**<0.01 lb/hr**	$= H_H * F_{N2O}$
N_2O Annual Emission Rate	ER_{N2OA}	**<0.01 tpy**	$= H_A * F_{N2O}$ / 2000 lbs/ton
Hourly Global Warming Potential	GWP_{N2OH}	0.26 lb/hr	$= ER_{N2OH} * 310\ CO_2e$
Annual Global Warming Potential	GWP_{N2OA}	1.15 tpy	$= ER_{N2OA} * 310\ CO_2e$
5. Total CO_2e Emission Rates			
Hourly Global Warming Potential	-	**493 lb/hr**	$= ER_{CO2H} + GWP_{CH4H} + GWP_{N2OH}$
Annual Global Warming Potential	-	**2,160 tpy**	$= ER_{CO2A} + GWP_{CH4A} + GWP_{N2OA}$

Notes:

1) Flow and composition from the compressor vent seals include supplemental natural gas (90% methane and 10% VOC estimate).

Table D-4
Flare - Maintenance, Startup, and Shutdown (MSS) Emissions Summary
Natgasoline, LLC - New GtG Plant

A. Annual Emission Rates

Source	CO_2	CH_4	N_2O	CO_2e
Synthesis Gas	11,165	2.08	0.02	11,214
Expansion Gas	223.69	0.48	<0.01	234
Equipment Clearing	1.55	<0.01	<0.01	1.62
Annual Total (tpy)	**11,390**	**2.57**	**0.02**	**11,450**

B. Hourly Emission Rates

Source	CO_2	CH_4	N_2O	CO_2e
Synthesis Gas	697,803	130.30	1.16	700,898
Expansion Gas	13,980.76	29.97	0.02	14,615.28
Equipment Clearing	203.35	0.18	0.02	212.90
Hourly Total (lb/hr)	**711,987**	**160**	**1.19**	**715,726**

Table D-5
Flare - Synthesis Gas MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

Parameter Name & Variable		Value & Units		Basis/Calculation/Notes
1. General Values and Calculations				
Hourly Vapor Mass to Flare	M_H	575,502	lb/hr	Based on Estimated Flow to Flare
Annual Vapor Mass to Flare	M_A	18,416,050	lb/year	Based on M_H * 8 hrs/event * 4 events/yr
Hourly Vapor Volume to Flare	Q_H	19.41	MMScf^3/hr	Based on Estimated Flow to Flare
Annual Vapor Volume to Flare	Q_A	621	MMScf^3/year	Based on Q_H * 8 hrs/event * 4 events/yr
Max. Hourly Vapor Heat Input to Flare	H_H	5,258	MMBtu/hr	Based on Typical Stream Composition and Flow
Annual Vapor Heat Input to Flare	H_A	168,257	MMBtu/year	Based on Typical Stream Composition and Flow
2. Flare Gas Composition		Volume %	MW	
CO_2 Volume Percent & Molecular Weight		8.57	44.01	Based on Typical Stream Composition
CO Volume Percent & Molecular Weight		21.20	28.01	Based on Typical Stream Composition
H_2 Volume Percent & Molecular Weight		68.26	2.02	Based on Typical Stream Composition
CH_4 Volume Percent & Molecular Weight		1.61	16.04	Based on Typical Stream Composition
C_{4+} Volume Percent & Molecular Weight		0.01	58.12	Based on Typical Stream Composition
N_2 Volume Percent & Molecular Weight		0.09	28.02	Based on Typical Stream Composition
H_2O Volume Percent & Molecular Weight		0.26	18.02	Based on Typical Stream Composition
3. CO_2 Emission Rate Calculations				
Total Molecular Weight	MW_T	11.43	lb/lb-mol	Based on Typical Stream Composition
Carbon Content	CC	0.33		= Σ (No. of Carbons * 12/MW_i * MW_i/MW_T)
CO_2 Hourly Emission Rate	ER_{CO2H}	**697,803**	**lb/hr**	= 44/12 * Q_H * CC * MW_T / 385 scf/lb-mol
CO_2 Annual Emission Rate	ER_{CO2A}	**11,165**	**tpy**	= 44/12 * Q_A * CC * MW_T / 385 scf/lb-mol / 2,000 lb/ton
4. CH_4 Emission Rate Calculations				
CH_4 Weight Percent	W_{CH4}	2.26	%	Based on Typical Stream Composition
Flare DRE for CH_4	%	99	%	TCEQ Flare Guidance Document (October 2000)
CH_4 Hourly Emission Rate	ER_{CH4H}	**130**	**lb/hr**	= W_{CH4} * M_H * (100%-DRE)
CH_4 Annual Emission Rate	ER_{CH4A}	**2.08**	**tpy**	= W_{CH4} * M_A * (100%-DRE) / 2000 lb/ton
Hourly Global Warming Potential	GWP_{CH4H}	2,736	lb/hr	= ER_{CH4H} * 21 CO_2e
Annual Global Warming Potential	GWP_{CH4A}	44	tpy	= ER_{CH4A} * 21 CO_2e

Table D-5
Flare - Synthesis Gas MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

5. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	0.00022 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
N_2O Hourly Emission Rate	ER_{N2OH}	**1.16 lb/hr**	$= H_H * F_{N2O}$
N_2O Annual Emission Rate	ER_{N2OA}	**0.02 tpy**	$= H_A * F_{N2O}$ / 2000 lbs/ton
Hourly Global Warming Potential	GWP_{N2OH}	358.60 lb/hr	$= ER_{N2OH} * 310\ CO_2e$
Annual Global Warming Potential	GWP_{N2OA}	5.74 tpy	$= ER_{N2OA} * 310\ CO_2e$
6. Total CO_2e Emission Rates			
Hourly Global Warming Potential	-	**700,898 lb/hr**	$= ER_{CO2H} + GWP_{CH4H} + GWP_{N2OH}$
Annual Global Warming Potential	-	**11,214 tpy**	$= ER_{CO2A} + GWP_{CH4A} + GWP_{N2OA}$

Table D-6
Flare - Expansion Gas MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

Parameter Name & Variable		Value & Units		Basis/Calculation/Notes
1. General Values and Calculations				
Hourly Vapor Mass to Flare	M_H	7,398	lb/hr	Based on Estimated Flow to Flare
Annual Vapor Mass to Flare	M_A	236,750	lb/year	Based on M_H * 8 hrs/event * 4 events/yr
Hourly Vapor Volume to Flare	Q_H	0.1493	$MMScf^3/hr$	Based on Estimated Flow to Flare
Annual Vapor Volume to Flare	Q_A	4.778	$MMScf^3/year$	Based on Q_H * 8 hrs/event * 4 events/yr
Max. Hourly Vapor Heat Input to Flare	H_H	75.76	MMBtu/hr	Based on Typical Stream Composition and Flow
Annual Vapor Heat Input to Flare	H_A	2,424	MMBtu/year	Based on Typical Stream Composition and Flow
Weight Percent C_2/C_3 Vapors	$W_{C2/C3}$	10.8	%	Based on Typical Stream Composition
Weight Percent C_{4+} Vapors	W_{C4+}	2.9	%	Based on Typical Stream Composition
2. Flare Gas Composition		Volume %	MW	
CO_2 Volume Percent & Molecular Weight		16.73	44.01	Based on Typical Stream Composition
CO Volume Percent & Molecular Weight		1.93	28.01	Based on Typical Stream Composition
H_2 Volume Percent & Molecular Weight		25.17	2.02	Based on Typical Stream Composition
CH_4 Volume Percent & Molecular Weight		48.23	16.04	Based on Typical Stream Composition
C_2H_6 Volume Percent & Molecular Weight		2.19	30.07	Based on Typical Stream Composition
C_3H_8 Volume Percent & Molecular Weight		1.38	44.09	Based on Typical Stream Composition
C_4H_{10} Volume Percent & Molecular Weight		0.58	58.12	Based on Typical Stream Composition
C_5H_{12} Volume Percent & Molecular Weight		0.17	72.14	Based on Typical Stream Composition
C_6H_{14} Volume Percent & Molecular Weight		0.12	86.18	Based on Typical Stream Composition
N_2 Volume Percent & Molecular Weight		1.04	28.02	Based on Typical Stream Composition
Ar Volume Percent & Molecular Weight		0.00	39.94	Based on Typical Stream Composition
H_2O Volume Percent & Molecular Weight		0.08	18.02	Based on Typical Stream Composition
CH_3OH Volume Percent & Molecular Weight		2.20	32.04	Based on Typical Stream Composition
Low Boilers (assumed DME) Volume Percent & Molecular Weight		0.18	46.07	Based on Typical Stream Composition

Table D-6
Flare - Expansion Gas MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

Parameter Name & Variable		Value & Units	Basis/Calculation/Notes
3. CO_2 Emission Rate Calculations			
Total Molecular Weight	MW_T	19.10 lb/lb-mol	Based on site-specific stream composition
Carbon Content	CC	0.51	= Σ (No. of Carbons * 12/MW_i * MW_i/MW_T)
CO_2 Hourly Emission Rate	ER_{CO2H}	**13,981 lb/hr**	= 44/12 * Q_H * CC * MW_T / 385 scf/lb-mol
CO_2 Annual Emission Rate	ER_{CO2A}	**224 tpy**	= 44/12 * Q_A * CC * MW_T / 385 scf/lb-mol / 2,000 lb/ton
4. CH_4 Emission Rate Calculations			
CH_4 Weight Percent	W_{CH4}	40.51 %	Based on Typical Stream Composition
Flare DRE for CH_4	%	99 %	TCEQ Flare Guidance Document (October 2000)
CH_4 Hourly Emission Rate	ER_{CH4H}	**29.97 lb/hr**	= W_{CH4} * M_H * (100%-DRE)
CH_4 Annual Emission Rate	ER_{CH4A}	**0.48 tpy**	= W_{CH4} * M_A * (100%-DRE) / 2000 lb/ton
Hourly Global Warming Potential	GWP_{CH4H}	629.35 lb/hr	= ER_{CH4H} * 21 CO_2e
Annual Global Warming Potential	GWP_{CH4A}	10.07 tpy	= ER_{CH4A} * 21 CO_2e
5. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	0.00022 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
N_2O Hourly Emission Rate	ER_{N2OH}	**0.02 lb/hr**	= H_H * F_{N2O}
N_2O Annual Emission Rate	ER_{N2OA}	**<0.01 tpy**	= H_A * F_{N2O} / 2000 lbs/ton
Hourly Global Warming Potential	GWP_{N2OH}	5.17 lb/hr	= ER_{N2OH} * 310 CO_2e
Annual Global Warming Potential	GWP_{N2OA}	0.08 tpy	= ER_{N2OA} * 310 CO_2e
6. Total CO_2e Emission Rates			
Hourly Global Warming Potential	-	**14,615.28 lb/hr**	= ER_{CO2H} + GWP_{CH4H} + GWP_{N2OH}
Annual Global Warming Potential	-	**233.84 tpy**	= ER_{CO2A} + GWP_{CH4A} + GWP_{N2OA}

Table D-7
Flare - Equipment Clearing MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

Parameter Name & Variable		Value & Units		Basis/Calculation/Notes
1. General Values and Calculations				
Total Equipment Volume	V_T	6,463	ft^3	Based on Total Volume of All Vessels With Additional 30% Factor for Pumps and Piping
Volume of Largest Vessel	V_L	1,695	ft^3	Largest Volume of Gas for Worst-case Hourly Emission Rate
MSS Event per Hour	E_{hour}	1	hour	Assumed Worst-case
Number of Events per Year	E_{Year}	4	events	Assumed Worst-case
Gas Constant	R	11	psia ft^3/lb-mole °R	Global Constant
Total Pressure	P	15	psia	Atmospheric Pressure
Maximum Daily Vapor Pressure	P_{VA}	9	psia	Based on vapor pressure of Gasoline (RVP 12) in July
Density of Gasoline (RVP 12)	ρ	6	lb/gal	Typical Density of Gasoline (RVP 12)
Average Vapor Molecular Weight	M_V	64	lb/lb-mole	Based on TANKS 4.0.9d report for Gasoline (RVP 12)
Heating Value of Process Stream	HV	21,070	Btu/lb	Based on AP-42 Appendix A
Residual Liquid Volume	-	5	%	Conservatively Assume -% of Volume is Routed to Flare or Atmosphere as Liquid
Flare Destruction Efficiency	DRE	98	%	TCEQ Flare Guidance Document (October 2000)
Purging Temperature	T	150	°F	Typical Value
		610	°R	= ("^{o}F" value) + 460
2. VOC Emission Rates From Flare				
Light Liquid Emissions from Flare	ER_{HRLY}	79.27	lb/event	= [(M_V * P_{VA} * V_L / R / T) + (Residual Liquid Volume % * V_L * 7.481 * ρ)] * (100 - DRE%)
Light Liquid Emissions from Flare	ER_{TOTAL}	302.35	lb/year	= [(M_V * P_{VA} * V_T / R / T) + (Residual Liquid Volume % * V_T * 7.481 * ρ)] * (100 - DRE%)
Hourly VOC Emissions	ER_{VOCH}	**79.27**	**lb/hr**	= ER_{HRLY} * E_{hour}
Annual VOC Emissions	ER_{VOCA}	**0.60**	**tpy**	= ER_{TOTAL} * E_{year} / 2,000 lb/ton
3. CO_2 Emission Rates From Flare				
CO_2 Emission Factor	F_{CO2}	120,000	lb/MMscf	AP-42, Table 1.4-2
Hourly CO_2 Emissions	ER_{CO2}	**203.35**	**lb/hr**	= (V_L * E_{Hour} / 1,000,000) * F_{CO2}
Annual CO_2 Emissions	ER_{CO2}	**1.55**	**tpy**	= (V_T * E_{Year} / 1,000,000) * F_{CO2} / 2,000 lb/ton

Table D-7
Flare - Equipment Clearing MSS Emission Calculations
Natgasoline, LLC - New GtG Plant

Parameter Name & Variable		Value & Units	Basis/Calculation/Notes
4. CH_4 Emission Rate Calculations			
CH_4 Emission Factor	F_{CH4}	0.00220 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
CH_4 Emissions from Flare	ER/ Volume	0.18 lb/event	= F_{CH4} * HV * ER/Volume VOC / 1,000,000 / (100-DRE%)
CH_4 Emissions from Flare	ER/ Volume	<0.01 ton/event	= (F_{CH4} * HV * ER/Volume VOC / 1,000,000 / (100-DRE%)) / 2,000 lb/ton
Hourly CH_4 Emissions	ER_{CH4}	**0.18 lb/hr**	= ER/Volume * E_{hour}
Annual CH_4 Emissions	ER_{CH4}	**<0.01 tpy**	= ER/Volume * E_{year}
Hourly Global Warming Potential	GWP_{CH4}	3.86 lb/hr	= ER_{CH4} * 21 CO_2e
Annual Global Warming Potential	GWP_{CH4}	0.03 tpy	= ER_{CH4} * 21 CO_2e
5. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	0.00022 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
N_2O Hourly Emission Rate	ER/ Volume	0.02 lb/event	= F_{N2O} * HV * ER/Volume VOC / 1,000,000 / (100-DRE%)
N_2O Annual Emission Rate	ER/ Volume	<0.01 ton/event	= (F_{N2O} * HV * ER/Volume VOC / 1,000,000 / (100-DRE%)) / 2,000 lb/ton
N_2O Hourly Emission Rate	ER_{N2O}	**0.02 lb/hr**	= ER/Volume * E_{hour}
N_2O Annual Emission Rate	ER_{N2O}	**<0.01 tpy**	= ER/Volume * E_{year}
Hourly Global Warming Potential	GWP_{N2O}	5.70 lb/hr	= ER_{N2O} * 310 CO_2e
Annual Global Warming Potential	GWP_{N2O}	0.04 tpy	= ER_{N2O} * 310 CO_2e
6. Total CO_2e Emission Rates			
Hourly Global Warming Potential	-	**212.90 lb/hr**	= ER_{CO2} + GWP_{CH4} + GWP_{N2O}
Annual Global Warming Potential	-	**1.62 tpy**	= ER_{CO2} + GWP_{CH4} + GWP_{N2O}

Table D-8
Vapor Combustor for Product Loading Operations - Potential Emissions
Natgasoline, LLC - New GtG Plant

A. Input Data for Emission Calculations	**Value**	**Basis**
Fuel Type(s):	Mixture of Natural Gas and Gasoline/MeOH Loading Vapors	Design
Average Natural Gas Heating Value:	1,020 Btu/scf	AP-42 value
Average Waste Gas Heating Value:	20,400 Btu/lb (HHV)	Based on motor gasoline vapor
Average Annual Natural Gas Firing Rate:	2.00 MMBtu/hr	Natural gas flow to vapor combustor during hot standby
Maximum Hourly Waste Gas Flow:	2,910lb VOC/hr 59.4 MMBtu/hr	Based on maximum hourly collected vapors from barge loading, truck loading, and railcar loading (1)
Average Annual Waste Gas Flow:	2,240,528 lb VOC/yr 45,707 MMBtu/yr	Based on total annual collected vapors from worst-case transport method (railcar loading) (2)

B. Emission Calculations

Pollutant	Emission Factor (3)	Hourly PTE lb/hr	Annual PTE tpy
CO_2	117.65 lb/MMBtu	6,984	2,689
CH_4	0.0022 lb/MMBtu	0.13	0.05
N_2O	0.00022 lb/MMBtu	0.01	0.01
CO_2e (4)	117.78 lb/MMBtu	6,992	2,692

Notes:

(1) The maximum hourly waste gas flow rate is estimated from the conservative assumption that any loading method (barge, railcar, or truck) can occur at the same time .

(2) Railcar loading and barge loading cannot occur at the same time. Therefore, the average annual waste gas flow rate is estimated from the worst-case transport method - railcar loading.

(3) Indicated factors are from AP-42 Table 1.4-2. Listed lb/million scf values are divided by 1,020 to convert to lb/MMBtu.

(4) The CO_2e emission factor is based on the sum of the CO_2, CH_4, and N_2O emission factors multiplied by their respective global warming potential factors in 40 CFR Part 98 Subpart A, Table A-1.

Example Calculations:

Hourly PTE (lb/hr) = Max Natural Gas Flow (MMBtu/hr) * Emission Factor (lb/MMBtu)

Annual PTE (tpy) = Avg Gas Flow (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8,760 hr/yr / 2,000 lb/ton

Table D-9
Fugitive Equipment Components - Potential Emissions
Natgasoline, LLC - New GtG Plant

Equipment Leaks for MeOH Unit

Component Type and Service	Estimated Number of New Components	USEPA SOCMI w/out C2 Emission Factor (1) (lb/hr-component)	Control Efficiency (2) (percent)	Calculated Emission Rates (3)	
				lb/hour	tpy
Valves Gas/Vapor (Fuel Gas System Fugitives) (4)	422	0.0089	97	0.11	0.49
Compressors Gas/Vapor (Fuel Gas System Fugitives) (4)	1	0.5027	85	0.08	0.33
Flanges Gas/Vapor (Fuel Gas System Fugitives) (4)	1,055	0.0029	30	2.14	9.38
			Total VOC	**0.23**	**1.02**
			Total CH_4	**2.10**	**9.18**
			Total CO_2e (5)	**44.03**	**192.86**

Notes:

1) Air Permit Technical Guidance Package for Chemical Sources - Equipment Leak Fugitives. TCEQ. (October 2000).

2) Control efficiencies based on TCEQ Leak Detection and Repair Program 28VHP and water-seals on drains. All relief valves are routed to flare for control. Connectors in light liquid service will be monitored annually based on requirements for connectors under HON.

3) Sample Calculations - Fugitive Emissions (Gas/Vapor Valves)

lb VOC / hr = 422 gas/vapor valves * 0.0089 lb VOC / hr / component * (100% -97%) = 0.11 lb VOC/hr

tons VOC / yr = 0.11 lb VOC / hr * 8760 hr /yr / 2000 lb/ton = 0.49 tons VOC/yr

4) Fuel gas system fugitives contain 90% methane and 10% VOC.

5) Global warming potential factor for CH_4 is 21 as indicated on 40 CFR Part 98 Subpart A, Table A-1.

Table D-10
Fugitive Equipment Components - Potential Emissions
Natgasoline, LLC - New GtG Plant

Equipment Leaks for MTG Unit

Component Type and Service	Estimated Number of New Components	USEPA SOCMI w/out C2 Emission Factor (1) (lb/hr-component)	Control Efficiency (2) (percent)	Calculated Emission Rates (3)	
				lb/hour	tpy
Valves Gas/Vapor (Fuel Gas System Fugitives) (5)	301	0.0089	97	0.07	0.32
Compressors Gas/Vapor (Fuel Gas System Fugitives) (5)	1	0.5027	85	0.07	0.30
Flanges Gas/Vapor (Fuel Gas System Fugitives) (5)	753	0.0029	30	1.37	6.02
			Total VOC	**0.15**	**0.66**
			Total CH_4	**1.36**	**5.97**
			Total CO_2e (5)	**28.63**	**125.42**

Notes:

1) Air Permit Technical Guidance Package for Chemical Sources - Equipment Leak Fugitives. TCEQ. (October 2000).

2) Control efficiencies based on TCEQ Leak Detection and Repair Program 28VHP and water-seals on drains. All relief valves are routed to flare for control.

3) Sample Calculations - Fugitive Emissions (Gas/Vapor Valves)

lb VOC / hr = 301 gas/vapor valves * 0.0089 lb VOC / hr / component * (100% -97%) = 0.07 lb VOC/hr

tons VOC / yr = 0.07 lb VOC / hr * 8760 hr /yr / 2000 lb/ton = 0.32 tons VOC/yr

4) Fuel gas system fugitives contain 90% methane and 10% VOC.

5) Global warming potential factor for CH_4 is 21 as indicated on 40 CFR Part 98 Subpart A, Table A-1.

Table D-11
Potential Greenhouse Gas Emissions from Process Vents
Natgasoline, LLC - New GtG Plant

A. Process Condensate Stripper Vents (Methanol)

Emission Source	Flow Rate		Mol Wt of Stream	% CO_2		% CH_4		Emission Time [1]	CO_2 Calculated Emission Rates [2]		CH_4 Calculated Emission Rates [2]	
	lbmol/hr	lb/hr	lb/lbmol	mol%	wt%	mol%	wt%	hrs/yr	lb/hr	TPY	lb/hr	TPY
Strip Stream Process Condensate Stripper D-01501	621.7	12,849	20.66	0.950%	2.024%	0.010%	0.008%	8760	**260**	**1,139**	**1.00**	**4.37**
Strip Stream Process Condensate Degasser D-05001	890.9	22,343	25.06	0.470%	0.824%	-	-	8760	**184**	**806**	**-**	**-**
Total (Methanol)									444	1,945	1.00	4.37

B. Catalyst Regeneration (MtG)

Emission Source	Flow Rate		Mol Wt of Stream	% CO_2		% CH_4		Emission Time [1]	CO_2 Calculated Emission Rates [2]		CH_4 Calculated Emission Rates [2]	
	lbmol/hr	lb/hr	lb/lbmol	mol%	wt%	mol%	wt%	hrs/yr	lb/hr	TPY	lb/hr	TPY
Vented Gas from Main Burn (MtG)	836.1	25,719	30.72	17.586%	25.192%	-	-	1681	**6,479**	**5,446**	**-**	**-**
Total (MtG)									6,479	5,446	-	-

Emission Source	CO_2e Emission Rates [3]	
	lb/hr	tpy
Process Condensate Stripper Vent D-01501 (Methanol)	281	1,231
Process Condensate Degasser Vent D-05001 (Methanol)	184	806
Catalyst Regeneration (MtG)	6,479	5,446
Total CO_2e	6,944	7,483

Notes:

1) Emission time for each catalyst regeneration burn phase is based on the catalyst being regenerated approximately 110 times each year.

2) Sample Calculations - CO_2 Emissions (Vented Gas from Main Burn)

TPY CO2 = 25719 lb/hr * 0.2519 lb/lb

TPY CO2 = 25719 lb/hr * 0.2519 lb/lb * 1681 hrs/yr * 8,760 hrs/yr

3) Global warming potential factor for CO_2 is 1 and 21 for CH_4 as indicated on 40 CFR Part 98 Subpart A, Table A-1.

Table D-12
Potential Greenhouse Gas Emissions from Emergency Equipment
Natgasoline, LLC - New GtG Plant

A. Emission Factors and Global Warming Potential (GWP) Equivalency Factors

CO_2(1)	73.96	kg CO_2/MMBtu	&	**CO_2(2)**	=	1 ton of CO2 equivalent
CH_4(1)	0.003	kg CH_4/MMBtu	&	**CH_4(2)**	=	21 tons of CO2 equivalent
N_2O(1)	0.0006	kg N_2O/MMBtu	&	**N_2O(2)**	=	310 tons of CO2 equivalent

B. Emission Calculations

Emission Source	**Design Firing Rate (6)**		**CO_2 Emissions**		**CH_4 Emissions**		**N_2O Emissions**		**CO_2e Emissions (5)**	
	Max.	**Aver.**	**Hourly**	**Annual**	**Hourly**	**Annual**	**Hourly**	**Annual**	**Hourly**	**Annual**
	MMBtu/hr	**MMBtu/hr**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Emergency Engine	17	17	2,782	139	0.11	0.01	0.02	0.001	2,792	140
Firewater Pump Engines (7)	17	17	2,782	139	0.11	0.006	0.02	0.001	2,792	140
		Totals	**5,564**	**278**	**0.23**	**0.01**	**0.05**	**0.002**	**5,583**	**279**

Notes:

(1) Emission factors are based on 40 CFR Part 98 Subpart C, Table C-1 and Table C-2 for distillate fuel oil no. 2.

(2) Global warming potential factors are based on 40 CFR Part 98 Subpart A, Table A-1.

(3) Hourly emissions are based on the emission factor * max. hourly firing rate * 2.204 lb/kg.

(4) Annual emissions are based on the emission factor * aver. hourly firing rate (normal) * 2.204 lb/kg * 100 hours/year / 2000 lb/ton.

(5) CO_2e emissions are based on the sum of the CO_2, CH_4, and N_2O emissions times their respective GWP factors.

(6) The design firing rate is based on a 2,000 KW engine with 40% efficency.

(7) The design firing rate for both firewater pump engines is based on a 1,000 KW engine with 40% efficency.

APPENDIX E
PROPOSED BACT LIMITS AND COMPLIANCE DEMONSTRATION

Table E-1
Proposed BACT Limits and Compliance Demonstration
Natgasoline, LLC - New GtG Plant

GHG Emission Source	EPN	BACT Emission Limit	Compliance Demonstration Description	BACT Limit Compliance Determination Frequency
Methanol Reformer	B-01001	Minimum 90% Thermal Efficiency	1. An O_2 continuous monitoring system (CMS) will be installed in order to measure O2 concentration in the flue gas every 15 minutes. The required zero and span calibrations will take place daily and quarterly cylinder gas audits (CGAs) will also be performed. Records will be maintained onsite for a period of at least five years.	Rolling 12-month average basis
			2. A temperature monitor (ex. thermocouple) will be installed to record the temperatures of the combustion flue gas on a continuous basis.	Rolling 12-month average basis
			3. The thermal efficiency of the boiler will be calculated hourly using the parameters outlined in (1) and (2) above, excluding data from startups, shutdowns, and malfunctions. Thermal efficiency will be calculated using Equation G.1 in Annex G from the American Petroleum Institute's Standard 560. Records will be maintained onsite for a period of at least five years.	Rolling 12-month average basis
		Maximum 3% O_2 in stack gas (normal operation)	1. An O_2 CMS will be installed in order to measure O2 concentration in the flue gas every 15 minutes. The required zero and span calibrations will take place daily and quarterly CGAs will also be performed. Records will be maintained onsite for a period of at least five years.	Rolling 12-month average basis
		Maximum 350°F in stack gas (normal operation)	1. A temperature monitor (ex. thermocouple) will be installed to record the temperature of the combustion flue gas on a daily basis. Records will be maintained onsite for a period of at least five years.	Rolling 12-month average basis
Auxiliary Boiler	B-14001	Minimum 85% Thermal Efficiency	1. An O_2 CMS will be installed in order to measure O2 concentration in the flue gas every 15 minutes. The required zero and span calibrations will take place daily and quarterly CGAs will also be performed. Records will be maintained onsite for a period of at least five years.	Rolling 12-month average basis
			2. A temperature monitor (ex. thermocouple) will be installed to record the temperatures of the combustion flue gas on a continuous basis.	Rolling 12-month average basis
			3. The thermal efficiency of the boiler will be calculated hourly using the parameters outlined in (1) and (2) above, excluding data from startups, shutdowns, and malfunctions. Thermal efficiency will be calculated using Equation G.1 in Annex G from the American Petroleum Institute's Standard 560. Records will be maintained onsite for a period of at least five years.	Rolling 12-month average basis

Table E-1
Proposed BACT Limits and Compliance Demonstration
Natgasoline, LLC - New GtG Plant

GHG Emission Source	EPN	BACT Emission Limit	Compliance Demonstration Description	BACT Limit Compliance Determination Frequency
Regeneration Heater	H-REGEN	Gaseous Fuel, Good Combustion Practices (1)	1. The heater burners will be cleaned during each unit turnaround, or at least every five years (whichever is less) to remove any buildup and maintain heat transfer efficiency. Records will be maintained onsite for a period of at least five years.	Minimum every five years
			2. The regeneration heater will be equipped with an automated air/fuel control system to maintain optimal combustion efficiency. The automated fuel/air control system will be calibrated and preventative maintenance will be performed at least quarterly. Records will be maintained onsite for a period of at least five years.	Quarterly
			3. The regeneration heater will be designed with materials that provide proper insulation in order to reduce heat transfer losses.	Design
MtG Reactor Heaters	H-RXH1-5	Gaseous Fuel, Good Combustion Practices (1)	1. The heater burners will be cleaned during each unit turnaround, or at least every five years (whichever is less) to remove any buildup and maintain heat transfer efficiency. Records will be maintained onsite for a period of at least five years.	Minimum every five years
			2. The MtG reactor heaters will be equipped with an automated air/fuel control system to maintain optimal combustion efficiency. The automated fuel/air control system will be calibrated and preventative maintenance will be performed at least quarterly.	Quarterly
			3. The MtG reactor heaters will be designed with materials that provide proper insulation in order to reduce heat transfer losses.	Design
MtG Heavy Gasoline Treater Heater	H-HGT	Gaseous Fuel, Good Combustion Practices (1)	1. The heater burners will be cleaned during each unit turnaround, or at least every five years (whichever is less) to remove any buildup and maintain heat transfer efficiency. Records will be maintained onsite for a period of at least five years.	Minimum every five years
			2. The heavy gasoline treater heater will be equipped with an automated air/fuel control system to maintain optimal combustion efficiency. The automated fuel/air control system will be calibrated and preventative maintenance will be performed at least quarterly.	Quarterly
			3. The heavy gasoline treater heater will be designed with materials that provide proper insulation in order to reduce heat transfer losses.	Design
Plant Flare	S-1001/MSS	Good Design and Combustion Practices, Minimize Flaring	1. A flow meter and composition analyzer will be installed on the flare header and will continuously take measurements of the flow to the flare and the flare gas composition. The flow meter and composition analyzer will be calibrated on a frequency as recommended by manufacturer specifications. Records will be maintained onsite for a period of at least five years.	Continuous
			2. The flare will be designed and operated in accordance with 40 CFR §60.18, including the minimum value of the waste heat gas, maximum tip velocity, and pilot flame monitoring (e.g., with a thermocouple, infrared monitor, or other equivalent).	Design
			3. The flare will achieve at least a 99% destruction efficiency for all carbon compounds with three carbons or less (including methane) and a 98% destruction efficiency for all carbon compounds with greater than 3 carbons.	Design
			4. Flaring as a result of MSS events will take place as quickly as is technically practicable.	MSS Event Duration

Table E-1
Proposed BACT Limits and Compliance Demonstration
Natgasoline, LLC - New GtG Plant

GHG Emission Source	EPN	BACT Emission Limit	Compliance Demonstration Description	BACT Limit Compliance Determination Frequency
Vapor Combustor	VCU-1	Limited Operating Hours, Good Combustion Practices (<0.5% of total CO_2e emissions)	1. VCU operation will be intermittent and will only take place during gasoline loading operations.	Loading Event Duration
			2. Only pipeline-quality natural gas will be used as supplemental fuel during loading operations.	Loading Event Duration
			3. Loading operations will be completed as quickly as is technically practicable.	Loading Event Duration
Catalyst Regeneration Vent	EPN-CATREGEN	Proper Operating Techniques (<0.5% of total CO_2e emissions)	1. The number of catalyst regenerations and the regeneration duration will be minimized as is technically practicable in order to maintain low CO_2e emissions.	Catalyst Regeneration Duration
Process Condensate Stripper and Degasser Vents	D-01501/D-50001	Proper Operating Techniques (<0.5% of total CO_2e emissions)	1. Company will re-evaluate proposed GHG emissions after operation and determine whether any operational adjustments would result in lower GHG emissions. Samples of the stack effluent will be taken on an annual basis and analyzed for composition. Sample records will be maintained onsite for a period of at least five years.	Annual
Process Fugitives	FUG-MEOH/FUG-MTG	Implementation of LDAR Program (<0.5% of total CO_2e emissions)	1. The 28VHP program will be implemented for streams that contain >10% methane by weight. Data and other records will be maintained onsite for a period of at least five years.	Quarterly
Emergency Generator and Firewater Pump Engines	H-EMG/H-FWP	Proper Operating Techniques, Limited Operating Hours (<0.5% of total CO_2e emissions)	1. The emergency generator and firewater pump engines will not be operated more than 100 hours per year, for non-emergency uses (e.g., testing). Run-time meters will be installed on all three engines.	Annual

Notes:

1) The smaller heaters in the MtG Unit all contribute <1.5 percent each to the total CO_2e emissions. Therefore, establishing a numerical BACT limit (such as thermal efficiency) to these heaters would not result in a significant reduction in GHG emissions.