Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Rohm and Haas Texas, Incorporated, Deer Park Plant

Permit Number: PSD-TX-1320-GHG

December 2013

This document serves as the statement of basis for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On October 26, 2012, the Rohm and Haas Texas, Incorporated (Rohm and Haas) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for greenhouse gas (GHG) emissions for a proposed boiler house unit expansion project at its Deer Park, Texas Plant. In connection with the same proposed project, a nonattainment new source review (NNSR) netting analysis for the ozone precursors nitrogen oxide (NOx) and volatile organic compounds (VOC) was submitted to the Texas Commission on Environmental Quality (TCEQ). The netting analysis demonstrated to TCEQ that the project does not constitute a major modification for ozone precursors NOx and VOC. Therefore, on October 12, 2012, Rohm and Hass submitted to TCEQ a new source review PSD permit application for carbon monoxide and particulate matter with diameters of 10 microns or less and 2.5 microns or less associated with the proposed project. The proposed project at the Deer Park, Texas plant would involve construction and installation of a two (2) new gas-fired steam boilers at the existing Boiler House Unit. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of GHG emission sources at the Rohm and Haas, Deer Park, Texas facility.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes initially that Rohm and Haas' application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's initial conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by Rohm and Haas, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

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III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305).

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:

Melanie Magee
Environmental Engineer
Air Permitting Section (6PD-R)
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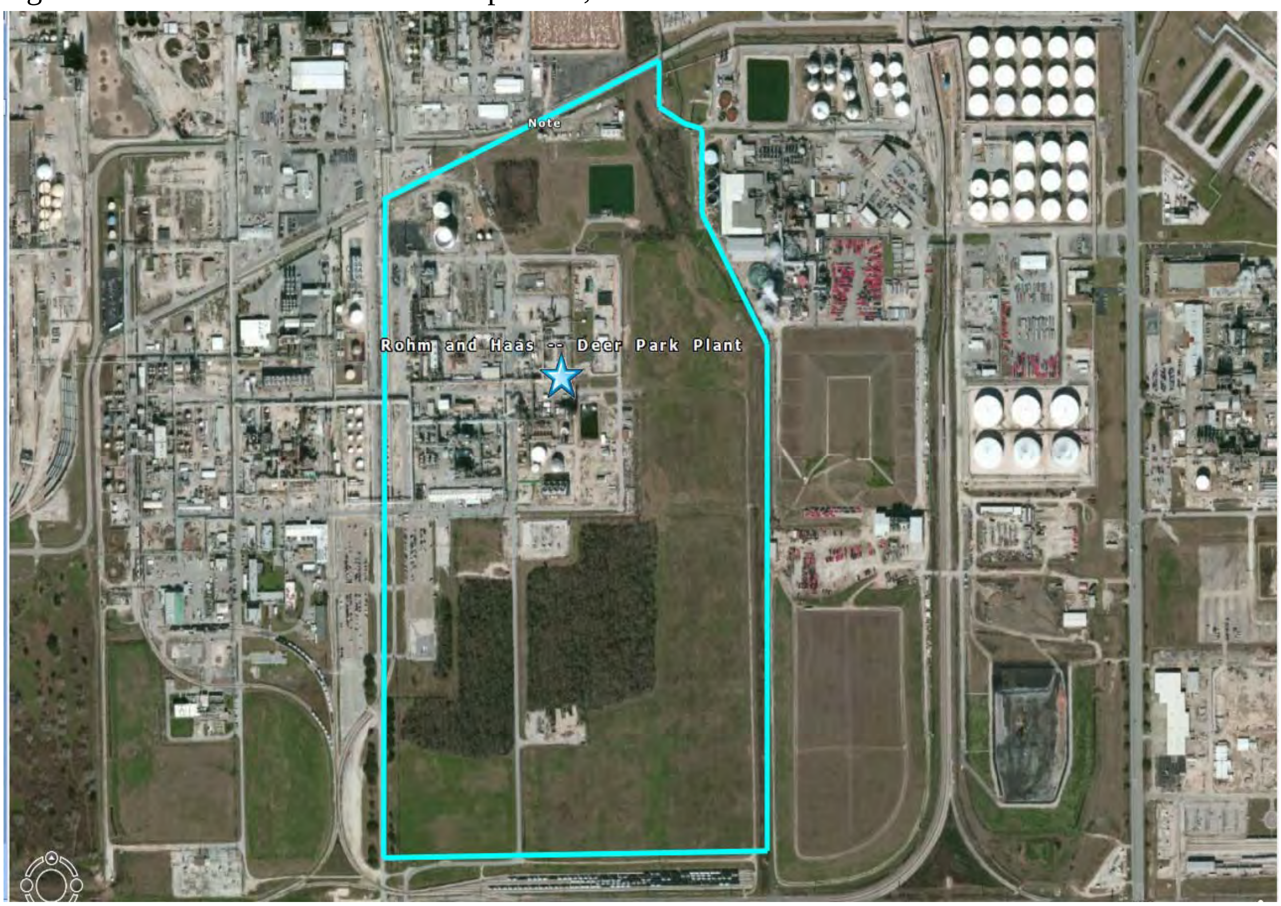
IV. Facility Location

The Rohm and Haas, Deer Park plant is located in Harris County, Texas. The geographic coordinates for this facility are as follows:

Latitude: 29º 43’ 40” North
Longitude: - 95º 55’ 59” West

Harris County is currently designated severe nonattainment for the 1997 8-hr ozone standard and marginal nonattainment for the 2008 8-hr ozone standard. Harris County is currently designated attainment for all other pollutants. The nearest Class I area, at a distance of more than 100 kilometers, is Breton National Wildlife Refuge.

Figure 1. Rohm and Haas Texas Incorporated, Deer Park



V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes Rohm and Haas’ application is subject to PSD review for the pollutant GHG, because the project would lead to an emissions increase of GHG for a facility in excess of the emission thresholds described at 40 CFR § 52.21 (b)(49)(iv). Under the project, the net GHG emissions are calculated to be a net emissions increase over zero tpy on a mass basis and to exceed the applicability threshold of 75,000 tpy CO_2e (Rohm and Haas calculates CO_2e emissions of 528,301.29 tpy) for a modification to an existing major facility that requires PSD review for its significant net emissions increases of several criteria pollutants. As noted above in Section III, EPA Region 6 implements a GHG PSD FIP for the Texas under the provisions of 40 CFR 52.21 (except paragraph (a)(1)). *See,* 40 CFR § 52.2305.

Rohm and Hass represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, will determine that Rohm and Haas is also subject to PSD review for emission increases of Carbon Monoxide (CO) and particulate matter (PM and PM_{10}) associated with this proposed project. Accordingly, under the circumstances of this project, TCEQ will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[1]

EPA Region 6 takes into account the policies and practices reflected in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011). Consistent with recommendations in that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions of 40 CFR §§52.21 (o) and (p), respectively. Instead, EPA has determined that compliance with the selected BACT is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the proposed project has regulated NSR pollutants that are non-GHG pollutants, which are addressed by the PSD permit to be issued by TCEQ.

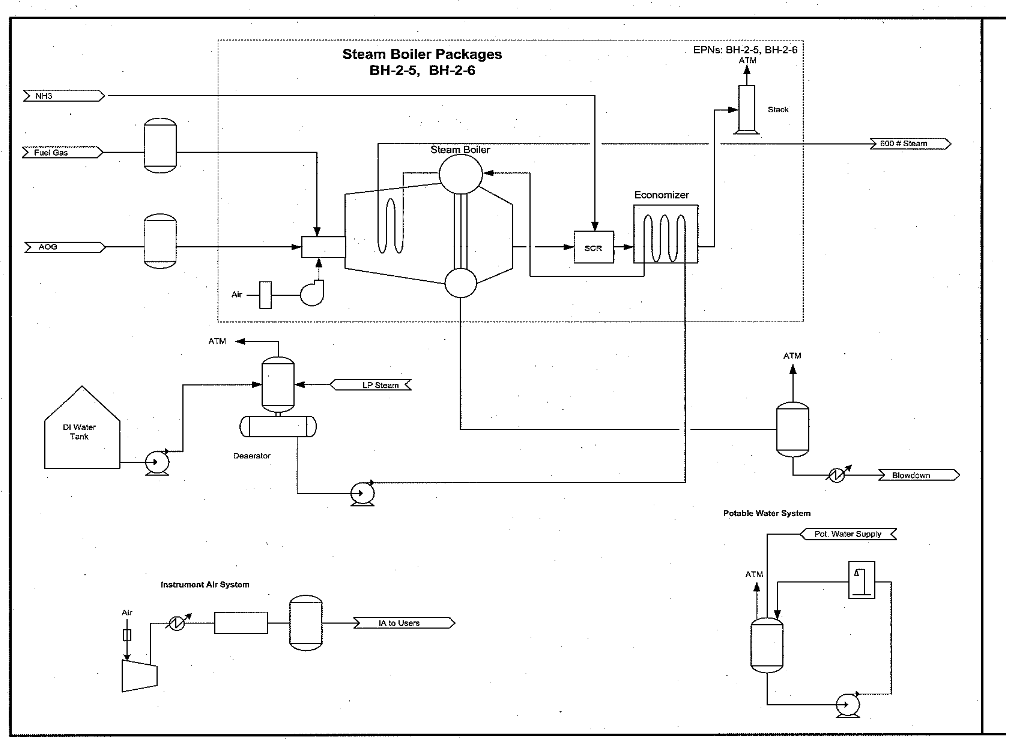
VI. Project Description

The proposed GHG PSD permit, if finalized, will allow Rohm and Haas to install two (2) new 515 MMBtu/hr gas-fired boilers and the associated piping and equipment at the Deer Park facility. Each boiler will be permitted to operate 8,760 hours per year. The purpose of the project is to provide Rohm and Haas with the ability to perform planned maintenance on steam producing equipment without sacrificing peak steam production, as well as, providing adequate reliability in efficiently burning the absorber off-gas (AOG) from the N-Area Unit. During normal operations, these boilers will burn either natural gas or a combination of natural gas and AOG from the N-Area Unit. During the boilers startup and shutdown activities, and when N-Area is down for maintenance, the boilers will only burn natural gas. During periods where demand for steam within the Deer Park site is low, these boilers will operate in hot standby mode. Hot standby mode will be utilized when steam production is curtailed and during this time the boilers will operate at less than full capacity; thereby reducing combustion optimization. When the boilers are in Hot Standby mode, the boilers will never exceed the proposed routine operating annual emission rates. Each boiler will be equipped with a Selective Catalytic Reduction (SCR) unit for NOx emission control.

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

Similar to most industrial boilers, water is fed through the boiler tubes where it is heated to a specific temperature in order to produce steam. This is accomplished by using natural gas or a combination of natural gas and AOG from the N-Area Unit within the Deer Park site. Through this process, each boiler will produce 600 pounds of steam to be supplied to manufacturing facilities within the Rohm and Haas Deer Park plant. The combusted gases from the boiler are fed through a SCR system where NOx emissions are reduced. The gas stream is then fed through an economizer to recover heat from the combusted gasses by increasing the temperature of the water being fed to the deaerator and on to the boiler as feed-water. This gas stream is then emitted from the boiler stack. A simplified process flow diagram is shown below in Figure 2.

Figure 2. Simplified Process Flow Diagram for the Steam Boiler



VII. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted in accordance with EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls and document the results; and
(5) Select BACT.

VIII. Applicable Emission Units and BACT Discussion

The majority of the GHGs, associated with the project are from combustion units (i.e., boilers). The site has some fugitive emissions from piping components that contribute a small amount of GHGs. These stationary combustion sources primarily emit carbon dioxide (CO_2), and small amounts of nitrous oxide (N_2O) and methane (CH_4). The following devices are subject to this GHG PSD permit:

- Boilers (EPNs: BH-2-5 and BH-2-6)
- Equipment Fugitives (EPN: BLR-FUG2)

CO_2 emissions account for approximately 99 percent (%) of the total CO_2e emissions for the proposed project. CH_4 and N_2O contribute insignificantly to the overall GHG emissions potential. Therefore the GHG BACT analysis is focused on CO_2.

The start-up and shutdown emissions have been considered in computing the total GHG emission increases. The permit, upon final issuance, will apply to all operating conditions including normal operations, maintenance, start-up, and shutdown for the Rohm and Haas, Boiler House Unit project.

IX. Boilers (EPNs: BH-2-5 and BH-2-6) BACT Analysis

The proposed boilers (BH-2-5 and BH-2-6) will burn either pipeline quality sweet natural gas or a combination of natural gas and AOG from the N-Area Unit. CO_2 will be emitted from the boilers because it is a combustion product of any carbon containing fuel. CH_4 will be emitted from the boilers as a result of any incomplete combustion. N_2O will be emitted from the boilers in trace quantities due to partial oxidation of nitrogen in the air which is used as the oxygen source for the combustion process.

Step 1 – Identification of Potential Control Technologies

The following technologies have been identified as potential control options for the gas-fired boilers.

- *Low Carbon Gaseous Fuels*- The combustion of fuels containing lower concentrations of carbon generates less CO_2 than the combustion of other higher-carbon fuels. Typically, gaseous fuels such as natural gas or AOG contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal. Rohm and Haas proposes to use natural gas or a blended fuel gas that consists of natural gas and AOG.
- *Good Combustion Practices and Maintenance*- Good combustion practices include appropriate maintenance of equipment, periodic burner tuning, good fuel/air mixing in the

combustion zone, and operating within the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control.

- *Energy Efficient Design*- To maximize the efficiency of the boilers, Rohm and Haas will operate the boilers as recommended by the boiler manufacturer to save energy and maximize the boiler efficiency
- *Carbon Capture and Storage (CCS)*- CCS is an available add-on control technology that is applicable for all of the site's affected combustion units.

Step 2 – Elimination of Technically Infeasible Alternatives

Carbon Capture and Sequestration (CCS)

CCS is a GHG add-on control process that can be used by "facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[2] CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion are not considered applicable control options for this proposed modification. The third approach, post-combustion capture, is available and applicable to the steam boilers.

Separating CO_2 from the boiler exhaust streams at the boiler house unit would be challenging because CO_2 is present in dilute concentrations in the boiler exhaust streams. The boiler exhaust gas has the potential to contain between 4.2 and 8.7 volumetric percent CO_2 in the stack gas on an average annual basis.[3] This CO_2 concentration is much lower than other types of industrial applications that may consider CCS. To achieve the necessary CO_2 concentration for effective sequestration, the recovery and purification of CO_2 from the stack gases would require additional equipment, operating complexity, and increased energy consumption, resulting in additional energy and environmental/air quality penalties.

Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced

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[2]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011)

[3] Permit Application Supplemental Information provided by Rohm and Haas, February 4, 2013, page 5.

oil recovery (EOR). The Hastings Oil Field, located north of Alvin, Texas, is in the advanced stage of primary depletion. The field is located approximately 30 miles from Deer Park and has been characterized for CO_2-EOR storage. Denbury Resources owns and operates the Green Pipeline that crosses the Galveston Bay and has a terminus point at the Hastings Field. Currently, there is no existing connection to the pipeline for Hastings Field from Deer Park.

Other potential sequestration sites, which are presently commercially viable, are in the range of 400 to 500 miles from the proposed project site. These sites include the Southeast Regional Carbon Sequestration Partnership (SECARB) Cranfield test site located in Mississippi's Adams and Franklin Counties and Scurry Area Canyon Reef Operators Committee (SACROC) EOR unit in the Permian Basin. Assuming it could be demonstrated that those sequestration sites can indefinitely store a substantial portion of the large volume of CO_2 generated by the proposed project, a very long and sizable pipeline would have to be constructed to transport the large volume of high-pressure CO_2 from the plant to the potential storage facility.

Post-combustion capture is considered challenging for this project. For the purposes of this BACT analysis, however, this CCS alternative remains under consideration. The remaining control options identified in Step 1 are all technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CCS (up to 90%)
- Low-Carbon Gaseous Fuels
- Energy Efficient Design
- Good Combustion and Maintenance Practices

CCS is capable of achieving a 90% reduction in CO_2 emissions and is therefore the most effective control method. Use of low-carbon fuel, energy efficient design, and good combustion practices are all considered effective and have a range of efficiency improvements that cannot be directly quantified. Therefore, the above ranking is approximate only. These technologies all may be used concurrently (including in conjunction with CCS). The estimated ranking is based on information obtained from Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008). This report addressed improvements to existing energy systems as well as efficiencies associated with new equipment.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

CCS:

Rohm and Haas developed a cost analysis for CCS that provided the basis for eliminating the technology in step 4 of the BACT process as a viable control option. The majority of the cost for CCS was attributed to the capture and compression facilities that would be required. The capital cost to construct a plant to process the gases from the boiler house unit would be approximately

$ 257,010,000. Annual costs (operating costs) for the CCS system would be approximately $40,282,966.

There are other potential storage sites, including enhanced oil recovery (EOR) sites and saline formations, that exist in Texas, Louisiana, and Mississippi. These reservoirs and other geologic formation sites are all in early development and are tenuous with regard to commercial viability and demonstration of large-scale, long-term CO_2 storage. Therefore the capital cost and legal risks of building infrastructure solely for CO_2 storage from this boiler expansion project are economically challenging. While there are salt dome caverns near the project site, these formations have not been demonstrated to safely store acid gases such as CO_2, nor is there adequate space available. Instead, these caverns are used for cyclical storage of liquefied petroleum gases (LPGs) for use in the Gulf Coast as well as for shipment throughout the United States via pipeline. The other potential sequestration sites in Texas that are commercially viable, such as the SACROC EOR unit and the SECARB test site are over 500 miles and 400 miles away from the proposed project site, respectively.

In an analysis provided by Rohm and Haas, an assumed pipeline length of 30 miles is used for CCS. This pipeline length was selected as the closest available pipeline alternative to the Hasting Field. Based on site specific estimates from the Dow Pipeline organization, typical pipeline costs for installation (including labor) in congested areas would be $2,000,000-$2,500,000 per mile. As noted in EPA's Permitting Guidance for Greenhouse Gases, we recognized the significant logistical hurdles that the installation and operation of a CCS system presents that sets it apart from the other add-on controls that are typically used to reduce emission of other regulated pollutants such as NOx or $SO_{2.}$ Essentially, requiring CCS for this facility would require the applicant to clear numerous logistical hurdles such as obtaining contracts for offsite land acquisition for pipeline right-of-way, construction of the transportation infrastructure, and potentially finding a customer(s) willing to purchase the CO_2.

The estimated total cost of the project without CCS is approximately $7,500,000.00 and the total cost with CCS addition is approximately $264.5 million. Therefore, the addition of CCS would increase the total capital project costs by more than 3,500%. Furthermore, the low purity and concentration of CO_2 in the boilers exhaust means that the per ton cost of removal and storage would be much higher for this project than for other industry categories and published estimates where the CO_2 concentration is significantly higher and easier to recover. Consequently, we agree with Rohm and Haas' cost analysis and conclude that CCS would be economically infeasible for this project.

Rohm and Haas also assert that CCS can be eliminated as BACT based on increase energy requirements and the environmental impacts resulting from a collateral increase of criteria pollutants (i.e. those pollutants for which EPA has promulgated primary and secondary National Ambient Air Quality Standards). Separating CO_2 from the boiler exhaust streams at the Boiler House Unit would be challenging because CO_2 is present in dilute concentrations. The boiler exhaust gas has the potential to contain between 4.2 and 8.7 % CO_2 by volume in the stack gas on an average annual basis. These are not high-purity streams. To achieve the necessary CO_2 concentration for effective sequestration, the recovery and purification of CO_2 from the stack gases would require additional equipment, operating complexity, and increased energy consumption from the plant resulting in energy and environmental/air quality penalties. This may, in turn, increase the natural gas fuel use of the plant to overcome these efficiency losses (with resulting increases in emissions of non-GHG pollutants), or could result in less energy being produced. The proposed plant is located in the Houston, Galveston, and Brazoria (HGB) area of ozone non-attainment and the generation of additional NOx and VOC could exacerbate ozone formation in the area. The estimated energy penalty as a result of CCS would be approximately 52% for this project. The basis for this energy penalty is to base the estimate on the power required for the capture of 90% of the CO_2. This estimate included a pumping/booster fan to get the CO_2 to the suction of the compressors, compression, air compressor, and steam generation. The power demand for transporting the CO_2 via pipeline was not known and would be an additional penalty for consideration.

Consequently, we agree with Rohm and Haas and conclude that the potential energy penalties and adverse environmental impacts, when considered in conjunction with the high costs, require the elimination of CCS as BACT for this specific site and project.

Low-Carbon Gaseous Fuel

CO_2 is a product of combustion generated with any carbon-containing fuel. The preferential use of gaseous fuels, such as natural gas or AOG, is a method of lowering CO_2 emissions at the Rohm and Haas site. Rohm and Haas proposes to use either pipeline quality natural gas or a combination of natural gas and AOG.

Good Combustion Practices

Another opportunity for reducing GHG emissions is good combustion practices and maintenance. These includes proper equipment maintenance and operation including periodic burner tuning, good fuel/air mixing in the combustion zone, proper fuel gas supply system design and operation to minimize instability of fuel gas during load changes, and sufficient excess air for complete combustion. Using good combustion practices results in longer life of the equipment and more efficient operation. Because CO_2 emissions are a direct result of the amount of fuel combusted, the more efficient the process, the less fuel that is required and the less GHG emissions that result. Rohm and Haas will adhere to these good combustion practices and maintenance as recommended by the boiler manufacturer.

Energy Efficient Design

The use of an energy efficient boiler design is economically and environmentally practicable for the proposed project. By optimizing energy efficiency, the project requires less fuel than comparable less-efficient operations, resulting in cost savings. Further, reduction in fuel consumption corresponding to energy efficient design reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing additional environmental. Specific technologies utilized by the furnaces include the following:

- Excess Air – The amount of air beyond stoichiometric combustion. Boiler efficiency decreases as excess air increases.
- Air Temperature – Boiler efficiency is relative to air temperature, typically 80°F. Efficiency increases at temperatures above this point and decreases when temperatures are colder.

- Exit Flue Gas Temperature – Temperature of flue gas leaving the boiler system. Heat transfer equipment extracts heat from the hot flue gases lowering their temperature.
- Fuel Composition – Particularly the presence of hydrogen and inerts. Boiler efficiency decreases as the percentage of hydrogen or inerts in the fuel increases. Two fuels will be utilized in the new boilers: natural gas and AOG. The carbon content of AOG is low, with the majority as CO and 7% as CO_2 and small traces of methane and ethane. Therefore, the sole combustion of AOG produces little GHG. The AOG must be co-fired with natural gas for safe and effective combustion. As the amount of AOG fueled is increased, less natural gas is fired. Boiler efficiency decreases, causing an incremental increase in GHG emissions from natural gas, but GHG emissions due solely to AOG combustion decreases. The net effect of increasing the amount of AOG fueled results in about 1% incremental increase of CO_2 emissions from no AOG to maximum AOG.
- Boiler Burner Tune-Ups – Periodic tune-ups (i.e., checks for the fuel/air mixing in combustion zone) on the boiler can help maintain boiler efficiency.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the table below:

Company / Location	Process Description	BACT Control(s)	BACT Emission Limit / Requirements	Year Issued	Reference
BASF FINA Petrochemicals LP, NAFTA Region Olefins Complex Port Arthur, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for steam package boilers - monitor and maintain a thermal efficiency of 77% 12-month rolling average basis	2012	PSD-TX-903-GHG
Chevron Phillips Chemical Company, Cedar Bayou Plant Baytown, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for the VHP boiler - monitor and maintain a thermal efficiency of 77% 12-month rolling average basis	2012	PSD-TX-748-GHG
PL Propylene, Houston, TX	Propylene Production	Energy Efficiency/Good Combustion Practices	GHG BACT for the boilers 117 lb CO_2/MMBtu heat input	2013	PSD-TX-18999-GHG
ExxonMobil, Mont Belvieu Plastics Plant Mont Belvieu, TX	Polyethylene production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for boiler - monitor and maintain a thermal efficiency of 77% 12-month rolling average basis	2013	PSD-TX-103048-GHG
Air Liquide Large Industries, Bayou Cogeneration Plant	Cogeneration Facility Redevelopment	Energy Efficiency/Good Combustion Practices	GHG BACT for the boilers 117 lb CO_2/MMBtu heat input	2013	PSD-TX-612-GHG

For comparison purposes, Rohm and Haas has proposed boilers that will meet a thermal efficiency of 76%. The Rohm and Haas thermal efficiency value is 1.3% less efficient than recently permitted boilers. The previously permitted boilers contained in the table above are fired with natural gas only (ExxonMobil) or a combination of other fuels (BASF and Chevron Phillips). In BASF and Chevron Phillips, the high heat value of the other fuels is higher than the high heat value of the AOG fuel for Rohm and Haas (i.e., 470 Btu/scf –Chevron versus 76.32 Btu/scf –Rohm and Haas). As previously mentioned, the Rohm and Haas boilers utilize natural gas and absorber off-gas (AOG). The carbon content of the AOG is low with the majority of emissions as CO and 7% of the emissions as CO_2 and small traces of methane and ethane. Therefore, the sole combustion of AOG produces little GHG. However, the AOG must be co-fired with natural gas for safe effective combustion. As the amount of AOG fuel is increased, less natural gas is fired. Boiler efficiency decreases, causing an incremental increase in GHG emissions from natural gas, but GHG emissions due solely to AOG combustion decreases. The net effect of increasing the amount of AOG fueled results in a decrease in GHG emissions.

Rohm and Haas' boilers will each meet a BACT limit of 117 lb CO_2/MMBtu (HHV) on a 12-month rolling average basis, which is applicable at all times. When calculating the BACT limit, utilizing the same parameters used to calculate the 76% thermal efficiency the BACT limit is 120.12 lb CO_2/MMBtu. This higher limit is 2.5% higher than other recently issued and drafted permits (PL Propylene and Air Liquide). During normal operation, Rohm and Haas plans to combust a combination of natural gas and AOG. With this blending of fuel sources, the BACT limit (lb CO_2/MMBtu) will decrease. Therefore, EPA believes that it is reasonable for Rohm and Haas to meet a BACT limit of 117 lb CO_2/MMBtu (HHV) on a 12-month rolling basis.

The following specific BACT practices are proposed for the boilers:

- *Low Carbon Fuels* – The boilers will fire, either pipeline quality natural gas or a combination of natural gas and AOG.
- *Good Combustion Practices and Maintenance* – The use of good combustion practices includes periodic tune-ups and maintaining the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control. These practices will include:
  - Boiler inspection to occur, at a minimum, of every 5 years. Inspection will include:
    - Checking the integrity of burner components (tips, tiles, surrounds);
    - Inspecting burner spuds for potential fouling;
    - Inspecting burner air doors and lubrication;
    - Inspecting all burners before closing main door to check for potential debris;
    - Inspecting combustion air ducting and dampers; and
    - Checking burner spud/orifice sizes.
  - Records will be maintained for any maintenance activity completed on the burners. The burners are to be inspected during routine scheduled maintenance periods.
- *Energy Efficient Operation* – The boiler will produce steam for use throughout the plant. Specific technologies utilized will include the following:
  - *Feedwater Preheat* - Use of heat exchangers/economizers to preheat incoming feedwater to minimize fuel usage in the firebox.

- *Flue Gas Heat Recovery* - Use of heat exchangers/economizers to use heat in the combustion gases in the boiler flue gas.

BACT Compliance:

BACT for the boilers will be 117.12 lb CO_2/MMBtu (HHV) on a 12-month rolling basis for each boiler. Rohm and Haas will demonstrate compliance with this BACT limit by measuring the CO_2 emissions using a Continuous Emissions Monitoring System (CEMS) and dividing by the weighted maximum heat capacity (HHV) of the fuel combusted in the boiler. The CO_2 CEMS will be installed and operated in accordance with 40 CFR Part 60, Appendix B Performance Specification 3 as applicable and the CO_2 CEMS will meet the appropriate quality assurance requirements specified in 40 CFR Part 60, Appendix F. Each boiler shall have fuel metering to measure the amount of fuel fired in the boiler. The maximum heat capacity (HHV) of the pipeline natural gas shall be determined twice in a calendar year pursuant to 40 CFR 98.34(a)(2)(i) and the HHV of the N-Area absorber off gas shall be determined pursuant to 40 CFR 98.34(a)(iii). When Rohm and Haas is firing a combination of natural gas and AOG, the weighted HHV shall be determined in accordance with 40 CFR 98.34(a)(3).

Compliance with the CO_2e emission limit for the boiler will be demonstrated by calculating the CO_2, CH_4 and N_2O emissions using the equations provided in 40 CFR Part 98 and measured parameters and adding the monthly calculation result to the rolling 12-month average. For the CO_2 calculation, the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1 and Equation C-5 shall be used for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii). The equation is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV). To calculate the CO_2e emissions, the permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the

Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1 (74 FR 56374 October 30, 2009)[4]. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month average, rolling monthly.

The proposed permit also includes an alternative compliance demonstration method, in which Rohm and Haas may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

An initial evaluation the boilers (BH-2-5 and BH-2-6) will be required to demonstrate compliance with the CO_2 emission limits established in the permit. Testing to demonstrate the CO_2 emissions shall also be performed every five years, plus or minus 6 months, of when the previous performance test was performed, or within 180 days after the issuance of a permit renewal.

During startup and shutdown of the new boilers (EPNs BH-2-5 and BA-2-6), the permittee shall burn only pipeline natural gas and will maintain the 117 lb CO_2/MMBtu on a 12-month rolling basis. A startup event is defined as the period of time when there is measureable natural gas flow to the boiler and ends when the boiler reaches 30 percent. Each startup time is limited to 24 hours per event per boiler. A shutdown event is defined as the period of time that begins when the boiler load falls below 20 percent and ends when there is no longer measureable fuel flow to the boiler. A shutdown is limited to 3 hours per event per boiler. Additionally, no more than one of the two boilers (EPNs BH-2-5 and BA-2-6) shall be shutdown and startup within the same hour. The new boilers are also limited to 270 hours of startup and shutdown operation per year. The natural gas burned during each startup and shutdown event shall be measured and recorded and shall be limited to 0.51 MMscf/hr.

X. Equipment Component Fugitives (EPN: BLR-FUG2) BACT Analysis

The proposed project will include new piping components for movement of gas and liquid raw materials, intermediates, and feedstocks. These components are potential sources of GHG emissions due to emissions from rotary shaft seals, connection interfaces, valves stems, and similar points. GHGs from piping component fugitives are mainly generated from lines containing natural gas and lines not in VOC service, but containing methane for the proposed project, but may be emitted from other process lines that are in VOC service.

Step 1 – Identification of Potential Control Technologies

Piping fugitives may be controlled by various techniques, including:

- Installation of leakless technology to eliminate fugitive emissions sources;
- Implementation of instrument leak detection and repair (LDAR) programs as prescribed by various federal and state regulations and permit conditions;

[4] On January 1, 2014, EPA anticipates the GWP for CH_4 will change from 21 to 25. This change will impact the CO_2e calculations and the currently proposed emission limits will be revised to reflect the new CH_4 GWP in the final permit

- Implementation of alternative monitoring using remote sensing using infrared cameras; and
- Implementation of audio/visual/olfactory (AVO) leak detection methods.

Step 2 – Elimination of Technically Infeasible Alternatives

- Leakless technology valves - Are used in situations where highly toxic or otherwise hazardous materials are present. These technologies cannot be repaired without a unit shutdown. Because natural gas and AOG are not considered highly toxic nor hazardous materials, these materials do not warrant the risk of unit shutdown for repair.
- *Instrument LDAR Programs* – Is considered technically feasible.
- *Remote Sensing* – Is considered technically feasible.
- *AVO Monitoring* – Emissions from leaking components can be identified through AVO methods. Natural gas and some process fluids are odorous, making them detectable by olfactory means. Therefore, use of as-observed AVO monitoring is considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Instrument LDAR programs and the alternative work practice of remote sensing using an infrared camera have been determined by EPA to be equivalent methods of controlling piping fugitives.

As-observed AVO methods are generally somewhat less effective because they are not conducted at specified intervals. However, because pipeline natural gas is odorized with very small quantities of mercaptan, as-observed olfactory observation is a very effective method for identifying and correcting leaks in natural gas systems. Due to the pressure and other physical properties of AOG, as-observed audio and visual observations of potential fugitive leaks are likewise moderately effective.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

As indicated in the GHG emission calculations, without the use of a monitoring/control program the contribution of GHG CO_2e emissions from fugitives is less than 0.02% of the total proposed project GHG CO_2e emissions. Due to the negligible amount of GHG emissions from process fugitives, the LDAR program is not cost effective as applied to GHG emissions alone. Therefore, the TCEQ 28-VHP leak detection and repair (LDAR) program is not economically feasible for this project.

Step 5 – Selection of BACT

The as-observed AVO program shall be used for detecting leaks in natural gas piping components and fugitive emission of methane from process lines not in VOC service but containing methane, including valves and flanges. The AVO monitoring shall be performed daily and records of the daily AVO monitoring results must be maintained on site and available for inspection. If a component is found to be leaking during the daily AVO inspection, the component shall be repaired within 15 days from identified of the leak.

XI. Endangered Species Act (ESA)

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant, Rohm and Haas Texas and its consultant, URS Corporation (URS), and adopted by EPA.

A draft BA has identified eighteen (18) species listed as federally endangered or threatened in Harris County, Texas:

Federally Listed Species for Harris County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Plant	
Texas prairie dawn flower	*Hymenoxys texana*
Birds	
Red-cockaded woodpecker Whooping crane	*Picoides borealis* *Grus americana*
Fish	
Smalltooth sawfish	*Pristis pectinata*
Mammals	
Louisiana black bear Red wolf West Indian manatee	*Ursus americanus luteolus* *Canis rufus* *Trichechus manatus*
Amphibians	
Houston toad	*Bufo houstonensis*
Marine mammals	
Blue whale Finback whale Humpback whale Sei whale Sperm whale	*Balaenoptera musculus* *Balaenoptera physalus* *Megaptera novaeangliae* *Balaenoptera borealis* *Physeter macrocephalus*
Reptiles	
Green sea turtle Kemp's ridley sea turtle Leatherback sea turtle Loggerhead sea turtle Hawksbill sea turtle	*Chelonia mydas* *Lepidochelys kempii* *Dermochelys coriacea* *Caretta caretta* *Eretmochelys imbricate*

EPA has determined that issuance of the proposed permit will have no effect on any of the eighteen listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

Because of EPA's "no effect" determination, no further consultation with USFWS or NMFS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XII. Magnuson-Stevens Act

The 1996 Essential Fish Habitat (EFH) amendments to the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) set forth a mandate for NOAA's National Marine Fisheries Service (NMFS), regional fishery management councils (FMC), and other federal agencies to identify and protect important marine and anadromous fish habitat.

To meet the requirements of the Magnuson-Stevens Act, EPA is relying on an EFH Assessment prepared by the applicant and reviewed and adopted by EPA.

The facility is adjacent to tidally influenced portions of the Buffalo Bayou connecting to the Houston Ship Channel, which connects to the San Jacinto River and eventually empties into the Galveston Bay system. These tidally influenced portions have been identified as potential habitats for postlarval, juvenile, subadult and/or adult life stages of red drum (*Sciaenops ocellatus*), white shrimp (*Penaeus setiferus*), brown shrimp (*Penaeus aztecus*), dog snapper (*Lutjanus jocu*), gray snapper (*Lutjanus griseus*), lane snapper (*Lutjanus synagris*) and dwarf sandperch (*Diplectrum bivittatum*). The EFH information was obtained from the Gulf of Mexico Fishery Management Council (http://www.gulfcouncil.org/).

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permit allowing Rohm and Haas construction of two new gas-fired steam boiler units and associated piping equipment within the existing facility property will have no adverse impacts on listed marine and fish habitats.

XIII. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on a cultural resource report prepared by URS on behalf of Rohm & Haas, submitted on August 1, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be (1) approximately 0.93 acres of land that contains the construction footprint of the project and (2) the construction laydown area that is in close proximity to the project's construction area. The APE is located in a modern industrial facility in a highly developed, industrialized zone surrounded by oil and gas refineries. URS conducted a field survey of the property and desktop review within a 0.5-mile radius APE . This review included a search of the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Register of Historic Places (NRHP) website. Based on the results of the field survey, no archaeological resources or historic structures were found within the APE. Based on the desktop review for the site, no cultural resource sites were identified within a 0.5-mile radius of the APE,

EPA Region 6 determines that because no historic properties are located within the APE and that a potential for the location of archaeological resources within the construction footprint itself is low, issuance of the permit to Rohm and Haas will not affect properties potentially eligible for listing on the National Register.

On September 23, 2013, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XIV. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGS at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XV. Conclusion and Proposed Action

Based on the information supplied by Rohm and Haas, our review of the analyses contained the TCEQ NSR Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue Rohm and Haas a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

APPENDIX

Annual Facility Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month total, rolling monthly, shall not exceed the following:

Table 1. Annual Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
BH-2-5	BH-2-5	Boiler	CO_2	263,916.90	264,120.75	• 117 lb CO_2/MMBtu on a 12-month rolling basis. See permit conditions III.A.2 and 4.
			CH_4	3.95		
			N_2O	0.39		
BH-2-6	BH-2-6	Boiler	CO_2	263,916.90	264,120.75	• 117 lb CO_2/MMBtu on a 12-month rolling basis. See permit conditions III.A.2 and 4.
			CH_4	3.95		
			N_2O	0.39		
BLR-FUG2	BLR-FUG2	Fugitive Emissions	CO_2	No Numerical Limit Established[3]	No Numerical Limit Established[3]	Implementation of AVO program. See permit condition III.B.
			CH_4	No Numerical Limit Established[3]		
Totals[4]			**CO_2**	**527,883.95**	**528,301.29**	
			CH_4	**10.74**		
			N_2O	**0.78**		

1. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
2. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310. On January 1, 2014, EPA anticipates the GWP for CH_4 will change from 21 to 25. This change will impact the CO_2e calculations and the currently proposed emission limits will be revised to reflect the new CH_4 GWP in the final permit.
3. Fugitive process emissions from EPN BLR-FUG2 are estimated to be 0.15 TPY of CO_2 and 2.84 TPY of CH_4. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
4. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits

Appendix

From: Bass, Monique (MN)
To: Magee, Melanie
Subject: RE: Values used to calculate efficiency
Date: Friday, November 22, 2013 1:18:33 PM

Melanie,
Please refer to the values below in response to your question. Let me know if you have any additional concerns.

76% boiler efficiency calculation:

Ms = steam flow = 207,000 lb/hr
Mf = BFW flow = 211,200 lb/hr
%BD = blowdown = 2%
Hs = steam exit enthalpy = 1349.2 Btu/lb
Hf = Inlet BFW enthalpy = 205.1 Btu/lb
Hd = drum enthalpy = 477.8 Btu/lb
qNG = natural gas flow = 33,000 scfh
qAOG = AOG flow = 3,600,000 scfh
HNG = natural gas HHV = 1017 Btu/scf
HAOG = AOG HHV = 77.8

Efficiency = [207000 (1349.2 – 205.1) + 211,200 * 0.02 * (477.8 – 205.1)] / [33,000 * 1017 + 3,600,000 * 77.8]

Efficiency = 76%

Regards,

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