# APPENDIX E

## Best Available Control Technology (BACT) for GHG

The permitting of the TFO project requires the employment of best available control technology for Greenhouse Gases (GHG). Effective 2011, U.S. EPA's Greenhouse Gas Tailoring Rule[1] requires projects to undergo PSD review for GHG emissions if the project increases GHG emissions by more than 75,000 tons/year $CO_2e$. This project has the potential to increase GHG emissions by more than this amount. Therefore, GHG BACT applies. This GHG BACT analysis has been prepared consistent with recent US EPA guidance[2].

### E.1 Top-Down BACT Process Background

BACT is defined in the Clean Air Act as *"an emissions limit based on the maximum degree of emissions reduction for each pollutant...which the permitting authority determines, on a case by case basis, taking into account energy, environmental, and economic impacts and other costs, is achievable for such facility through the application of production processes and available methods, systems, and techniques..."*.

The traditional BACT analysis involves a "top-down" process evaluating all potentially applicable emission control technologies. Evaluation begins with the top or most potentially effective of these emission control alternatives. If the most stringent control technology is shown to be technically or economically infeasible, or if the energy, environmental or other impacts are severe enough to preclude its use, then it is eliminated from consideration and the next most stringent control technology is similarly evaluated. This process continues until the BACT option under consideration cannot be eliminated. The top control alternative that is not eliminated is determined to be BACT. This process commonly involves the following five steps:

- **Step 1**: Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
- **Step 2:** Eliminate all technically infeasible control technologies;

1 Greenhouse Gas Tailoring Rule – (75 Fed. Reg. 31514, June 3, 2010)

2 PSD and Title V Permitting Guidance for Greenhouse Gases, US EPA, November 2010 & March 2011.

- **Step 3:** Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;
- **Step 4:** Evaluate most effective controls and document results; and
- **Step 5:** Select BACT, which will be the most effective practical option not rejected based on economic, environmental, and/or energy impacts.

Historically, BACT has not been required for $CO_2$ or other GHGs. As a result, there is little precedent for this assessment. US EPA has issued general and refinery-specific guidance, but there are only a few available PSD BACT analyses to serve as examples. Nevertheless, BPH has prepared this BACT analysis consistent with US EPA guidance, and following the long-standing approach used for criteria pollutants.

## E.2 Emission Units Subject to GHG BACT

Emission units that are subject to the requirement for GHG BACT are only those that are new or modified and have an increase in GHG emissions as a result of this project. Emission units that are unchanged by the project are not subject to BACT.[3] The emission units that are subject to GHG BACT and their estimated total annual $CO_2e$ emissions are included in the table below.

**Table E-1. Units Subject to GHG BACT**

| Emission Unit | Status | Emissions $CO_2$ tpy | Emissions $CO_2e$ tpy |
|---|---|---|---|
| Crude 1 Heater | New | 247,038 | 248,149 |
| Vac 1 Heater | New | 82,345 | 82,716 |
| Coker 3 Drum Vent | Modified | 7.5 (38 tpy CH4) | 805 |
| Coker Gas Plant Fugitives (increase) | Modified | (3.18 tpy CH4) | 21.3 |

3 In the preamble for the 1980 rule that established the current version of 40 CFR 52.21(j)(3), EPA explained that "BACT applies only to the units actually modified." 45 FR 52676, 52681 (Aug. 7, 1980). Later in this preamble (at 52722), EPA elaborated as follows with a specific example:

> The proposal required BACT for the new or modified emissions units which were associated with the modification and not for those unchanged emissions units at the same source. Thus, if an existing boiler at a source were modified or a new boiler added in such a way as to significantly increase particulate emissions, only that boiler would be subject to BACT, not the other emissions units at the source.

See also *PSD and Title V Permitting Guidance for Greenhouse Gases*, US EPA, March 2011 page 23.

## E.3 New Refinery Heaters (Crude 1 & Vac 1) GHG BACT Analysis

This project will install three new natural draft process heaters. Two of the new heaters will serve together as new Crude 1 Furnaces and will each be designed to burn refinery fuel gas (RFG) at the design fuel flow rate of 225 MMBtu/hour (HHV). A third furnace with a design firing of 150 MMBtu/hr (HHV) will serve as the new Vacuum 1 furnace.

The heaters will generate three GHGs as a result of the normal combustion process: $CO_2$, $CH_4$ and $N_2O$. However, $CO_2$ is the by far the most significant. Nearly all of the fuel carbon (99.9%) in the fuel gas is typically converted to $CO_2$ during combustion. This conversion is relatively independent of boiler or heater fuel type. Fuel carbon that is not converted to $CO_2$ results in $CH_4$, CO, and/or VOC emissions due to incomplete combustion. The conditions that favor formation of $N_2O$ are typically the same as those that favor emissions of methane, which are low temperature or incomplete combustion. Even in units with poor combustion efficiency, the level of these pollutants is insignificant compared to $CO_2$ levels. Therefore, the GHG analysis for combustion units focuses on just $CO_2$. $CO_2$ is an effective surrogate for all combustion $CO_2$ e. Also, options for controlling $CO_2$, such as ensuring complete combustion and maximum thermal efficiency, will minimize all three of the GHGs emitted.

### Steps 1 & 2 - Identify Potential Controls and Assess Feasibility

A review of the RACT/BACT/LAER Clearinghouse (RBLC)[4] and EPA Guidance Document on GHG Technologies[5] was conducted to identify potential controls on refinery heaters. The following table shows the results of the RBLC search for similar gas-fired heaters or boilers showing the technologies employed to minimize GHG emissions.

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4 http://cfpub.epa.gov/RBLC/

5 *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, US EPA Office of Air and Radiation, October 2010.

**Table E-2. Snapshot of Relevant GHG BACT Determinations (2011-2012)**

| Facility | State or RBLC # | Emission Unit | GHG BACT Requirements |
|---|---|---|---|
| PORT DOLPHIN ENERGY LLC | FL-0330 | 4- 278 MMBtu/hr Boilers (Natural Gas Fuel) | Tuning, optimization, instrumentation and controls, insulation, and turbulent flow. |
| PYRAMAX CERAMICS, LLC - KING'S MILL FACILITY | GA-0147 | 9.8 MMBtu/hr Boiler (Natural Gas Fuel) | Good Combustion Practices, design, and thermal insulation. 5,809 tons CO2e/rolling 12-months |
| NINEMILE POINT ELECTRIC GENERATING PLANT - ENTERGY LOUISIANA LLC | LA-0752 | 338 MMBtu/hr Auxiliary Boiler (Natural Gas Fuel) | Proper Operation and Good Combustion Practices<br>Use of Natural Gas Fuel |
| GEISMAR ETHYLENE PLANT | LA-0759 | 180 MMBth/hr Cracking Furnace (Natural Gas Fuel) | Low-emitting feedstocks,<br>Energy efficient equipment,<br>Process design improvement,<br>Low-emitting and low- carbon fuel (>25 vol% hydrogen, annual ave.) |
| PYRAMAX CERAMICS, LLC | SC-0113 | 5 MMBtu/hr Natural Gas Boilers | Good Design and Combustion Practices. Record type and quantity of fuel consumed. |
| Indiana Gasification (2012 IDEM permit 147-30464-00060) | Indiana (Not yet in RBLC) | 2 - 408 MMBtu/hr Auxiliary Boilers (with approx. 20% utilization) | Use of low-carbon gaseous fuel (natural gas or SNG); and<br>Energy efficient boiler design (utilizing an economizer, condensate recovery, inlet air controls and blowdown heat recovery)<br>CO2 < 88,167 tons per rolling 12-month period |

Based on a review of the available information and the project design, the control measures considered for the proposed process heaters include:

- Use of low-carbon gaseous fuel;
- Excess air minimization with $O_2$ monitoring and inlet air controls;
- Enhanced heat recovery (air preheat or convection section);
- Periodic burner tuning; and
- Post-combustion $CO_2$ capture and sequestration.

For the purpose of this analysis, each of these measures is considered technically feasible, and is evaluated further in the following sections.

## Steps 3 & 4– Ranking and Evaluation of Remaining Controls

*Low-Carbon Fuel*

The carbon content of the fuel, relative to its Btu value, can have significant impact on the overall GHG emissions. Gaseous fuels such as natural gas or refinery fuel gas (RFG) create significantly less GHG emissions per Btu than liquid or solid fuels. RFG is a mixture usually containing primarily methane (C1), with some content of C2-C4 hydrocarbons, hydrogen, and other gases that are the non-condensable products from the top of light-end distillation columns in the refinery. RFG is produced at multiple locations in the refinery and is treated to remove $H_2S$, and routed to a central location (mix drum) to supply fuel to various locations in the refinery. As an example, the Toledo RFG streams have GHG emission factors in the range of 105-130 lb $CO_2e$/MMBtu. This compares favorably to 117 lb/MMBtu for natural gas and is significantly lower than 160 lb/MMBtu for diesel fuel and 210 lb/MMBtu for coal. The use of low-carbon RFG fuel is a feasible option, and is proposed for use by the heaters.

*Excess Air Minimization with Oxygen Controls*

Fuel combustion in refinery heaters is accomplished when the hydrocarbon in the fuel is oxidized into carbon dioxide and water. Oxygen is provided for combustion by ambient air that is mixed with the fuel prior to or during combustion. Optimum combustion is achieved through a mixture of air and fuel with a little excess air. If too little air is used, combustion may not be complete resulting in CO and unburned hydrocarbons being emitted as incomplete combustion products. However, if too much air is introduced, additional energy is needed to heat the air and maintain combustion temperature. Some of the heat to heat excess air is recovered. However, the excess air carries much of that heat out the stack. Air slightly in excess of the ideal stoichiometric fuel/air ratio is required for safety and to ensure complete combustion (minimizing CO and VOC emissions). A target of about 3% oxygen in the stack is considered optimal.

The use of too much air increases fuel consumption which translates to an increase in $CO_2$ emissions. Therefore, good control of the oxygen level is helpful to minimize fuel consumption in refinery heaters.

The amount of air drawn into a natural draft furnace can be controlled by adjustments to either stack dampers or inlet air registers. Installation of an oxygen monitor on the stack of the heater gives the operator the ability to make adjustments to

these controls to optimize the excess air. Adjustments can be done manually on a periodic basis, or in some cases, can be automated. In this case, automation of the excess air control utilizing $O_2$ monitoring is a feasible strategy to minimize fuel use $CO_2$ emissions. BPH is proposing to install automated trim air controls on the proposed heaters.

*Enhanced Heat Recovery (Air Preheat or Convection Section)*

Measures to capture and productively utilize as much heat as reasonably possible from the warm stack gases will improve the energy efficiency of a heater (and decrease its GHG emissions). Two common methods of stack gas heat recovery from process heaters are use of either an air preheater or a convection section. Both methods introduce additional heat transfer surface area in contact with the warm stack flue gas to capture additional heat. An air preheater uses the recovered energy to raise the temperature of the combustion air. A convection section uses the heat to preheat the process liquid being heated by the heater or for some other direct process heat purposes. Either method will result in increased thermal efficiency of the heater by recovering more heat from the flue gas. The choice of which heat recovery method is best is project-specific and can achieve equivalent efficiency results. Refinery heaters most often recover the heat to preheat the process fluid in a convection section. Air preheating is typically used only on very large boilers and forced/induced draft heaters. Air heating on natural draft heaters is rarely utilized due to the need to overcome significant gas-side pressure drop increases. Also, air preheat may increase $NO_x$ emissions by increasing the flame temperature and causing more thermal $NO_x$ formation.

BPH is proposing to install convection sections for heat recovery on the new Crude and Vac 1 heaters. The addition of this additional heat transfer area to preheat the process fluids will reduce the overall fuel consumption resulting in lower $CO_2$ emissions from fuel combustion. The convection section will be designed to reduce the stack temperature as much as is reasonable for the proposed heater design and operation. Sufficient temperature is required in the stack for the natural draft furnace to operate properly, and to avoid condensation in the stack.

*Periodic Burner Tuning*

Periodic maintenance of the burners, as well as checks and cleaning of fouling can help maintain heater and boiler efficiency. Poor burner operation can result in excess fuel usage as well as increased GHG emissions. Periodic burner tuning is required bythe recent EPA Industrial and Commercial Boiler and Heater MACT regulation (Boiler

MACT) on an annual basis for heaters without automatic O2 trim control and every 5 years for heaters with O2 trim control. This option is considered feasible and BPH will implement burner tuning and inspections on the proposed heaters as currently required for large gas fired heaters at major sources in the Boiler MACT rule (every 5 years since the new and modified BPH heaters will have O2 trim control).

*Post-combustion $CO_2$ Capture and Sequestration*

Carbon Capture and Sequestration (CCS) is a relatively new concept. As previously mentioned, in EPA's recent GHG BACT guidance, EPA takes the position that, *"for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large $CO_2$ -emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity $CO_2$ streams"*. [6] However, the proposed refinery process heaters do not fit into either of these categories (i.e.; large emitting or high-purity). The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above quoted examples. However, some guidance specific to medium-sized natural gas boilers is provided in Appendix F to the guidance document which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this EPA boiler example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option[7].

Based on EPA's guidance, it seems clear that a $CO_2$ capture system for small to medium size combustion systems, such as the refinery process heaters, is not expected to be a reasonable BACT option. This is understandable because the capture of the $CO_2$ from a heater's exhaust is significantly more difficult than from the types of industrial gas streams that EPA references as having potential for CCS. The increased difficulty is due to four predominant factors: the heater exhaust's low $CO_2$ concentration, low pressure, low quantity of $CO_2$ available for capture, and the high variability of load for this unit. While these factors don't make it technically impossible, they do make it expensive and energy intensive as discussed below.

$CO_2$ Capture Difficulty : Gas fuel combustion exhaust streams have relatively low $CO_2$ concentrations. The exhaust streams are typically (6-9% $CO_2$ versus 12-15% for coal-

6 PSD and Title V Permitting Guidance For Greenhouse Gases, November 2010, US EPA Office of Air and Radiation, pg. 34, 35.

7 PSD and Title V Permitting Guidance For Greenhouse Gases, March 2011, US EPA Office of Air and Radiation, Appendix F, pg. F-1.

boilers and >30% for high concentration industrial gas streams.) This means that for a gas fired process heater or boiler, a very large volume of gas needs to be treated to recover the $CO_2$. Additionally, the low concentration and low pressure complicate the absorption and desorption of the $CO_2$, which increases the energy required. Also, a low pressure absorption system creates a low pressure $CO_2$ stream which requires a very high energy demand for compression prior to transport. All these factors make the application of $CO_2$ capture on any gas combustion exhaust extremely difficult and expensive.

Estimated Costs for Carbon Capture: The fact that CCS is too expensive can be illustrated quickly using industry estimates. By far the most significant costs are for capture of the $CO_2$ from the exhaust, and compressing it to the pressure required for transport and sequestration. The capture and compression steps are very energy-intensive and would also result in additional emissions of criteria pollutants. The *Report of the Interagency Task Force on Carbon Capture and Storage* (August 2010) reports that carbon capture is estimated to cost approximately $95/metric tonne $CO_2$ avoided ($105/ton) for a post-combustion system on a new installation.[8] These costs represent a levelized, or annualized, cost over the estimated life of the example configurations. If you apply this factor to the combined 330,864 tons/yr of $CO_2$ from the new Crude 1 and Vac 1 heaters, the cost for capture and compression alone (not including transport or sequestration) is approximately $34,600,000 per year. This cost estimate is an annual cost (including capital recovery costs). Over the first 10 years of operation these costs would exceed $300 million dollars. This is clearly an excessive cost.

Energy and other pollutants from Carbon Capture: In addition to the extremely high costs for CCS, it should be recognized that a large portion of these costs are energy related. The two largest energy requirements of carbon capture post-combustion are the energy required to regenerate the solvent and the energy to compress the captured $CO_2$ to typical pipeline pressures. Satisfying these high additional energy requirements create significant additional $CO_2$ emissions and emissions of other conventional pollutants.

[8] Various literature sources report a fairly wide range of costs for employing CCS systems (typically 60-120 $/ton $CO_2$ controlled). The range spanned by these cost estimates is driven primarily by site-specific considerations (especially $CO_2$ concentration) and energy cost assumptions. In addition, estimates of the future performance of components of the capture, transport, storage, measurement and monitoring systems are uncertain.

For example, regeneration of the solvent in available $CO_2$ capture technologies require approximately 1,550-3,000 Btu/lb of $CO_2$ removed.[9] This would equate to 117-226 MMBtu/hr of increased energy use associated with the capture of $CO_2$ from the two new heaters (which themselves have a combined design firing rate of (heaters with a design firing of 600 MMBtu/hr.) This does not include the significant power is required to compress the captured CO2 to typical pipeline pressures (1,500 – 2,200 psia).

These significant additional requirements for steam and electricity require fossil fuels to be combusted either on or off site. These energy demands of CCS contribute to its significant cost and generate negative environmental consequences through the extra criteria pollutant emissions.

Sequestration Site Non-availability: Because of the extremely high costs of carbon capture and compression, BPH does not believe that CCS is an economically feasible option for GHG controls on this project. Further, BPH is unaware of any available suitable sequestration site or $CO_2$ transportation infrastructure that could be used by this project. Therefore, we additionally believe that CCS is infeasible due to lack of currently available sequestration site for permanent storage of any $CO_2$ captured. A few of the main challenges and issues of sequestration are briefly discussed below.

- **Access to a suitable sequestration site.** BPH does not have access to a suitable sequestration site, nor can one be developed in any timeframe compatible with this project. While sequestration is being studied for use in this region, there is presently no practical option. Funding from the Department of Energy (DOE) is supporting a substantial research and demonstration initiative called the Regional Carbon Sequestration Partnership (RCSP) program. This program has begun several large-scale $CO_2$ injection research projects. However, the results of these demonstrations won't be known for some time. Also, given the unprecedented nature of the $CO_2$ sequestration, many technical and legal issues remain to be addressed including the public acceptability of storage at any given site. These issues make the ultimate development of future sites uncertain.

- **Access to available transportation infrastructure.** There are a number of $CO_2$ commercial outlets in the Gulf Coast and some western states for $CO_2$, primarily for use in enhanced oil recovery. These operations are served by a number of $CO_2$ pipelines. However, there is no existing pipeline infrastructure within hundreds of miles of the BPH facility. The nearest is over 700 miles away in

[9] *Report of the Interagency Task Force on Carbon Capture and Storage*, (August 2010)

Jackson, Mississippi. The logistical challenges of constructing a pipeline from the BPH facility hundreds of miles to join up with the existing $CO_2$ pipeline infrastructure is completely impractical.

### Step 5 - Selection of GHG BACT

For the technical, economic, and environmental reasons stated above, post-combustion capture of $CO_2$ from the proposed heaters is not considered an applicable and available control option. All other remaining technically feasible GHG control options are proposed as BACT:

- Use of low-carbon gaseous fuel (RFG or natural gas);
- Excess Air Minimization with $O_2$ monitoring and Inlet Air Controls
- Heat Recovery through use of a convection section; and
- Periodic burner tuning and heater inspection.

Compliance will be demonstrated through records of the heater design, records of fuel usage, and maintenance records. Additionally, total annual $CO_2$ emissions shall not exceed 247,038 tons per rolling 12 months for the new Crude 1 heater and 82,345 tons per rolling 12 months for the new Vacuum 1 heater. These emissions will be calculated monthly to develop a rolling 12-month sum. (Note: $CO_2$ emissions limits are proposed rather than $CO_2e$ because it represents over 99.5% of the $CO_2e$ emissions from these combustion sources and is therefore a good surrogate for total GHG emissions.)

## E.4 Coker 3 (P036) Drum Vent GHG BACT Analysis

During the bulk of the delayed coker operating cycle, vapors from the coke drum are routed to the coker product fractionator for liquid and gas product recovery and there are no emissions to the atmosphere. At the end of the coke drum cycle, after the drum is taken off line, it is depressured to a blowdown recovery system which routes the gas to the refinery fuel gas system.

The first emissions event occurs when the coke drum is vented to the atmosphere prior to it being opened to remove the accumulated coke. Residual vapors from the coking process that exist in equilibrium based on the temperature and pressure of the

coke drums are released to the atmosphere during this step. Prior to this atmospheric venting, the drum has been steamed out and water flooded. The gases from this atmospheric venting consists of primarily steam, along with residual vapors from the coking process, and includes the GHGs methane ($CH_4$) and $CO_2$.

There were no coking units found in the RBLC database. However, the EPA GHG Guidance for Refineries[10] listed lowering the pressure of the coke drum to 2 to 5 psig to minimize direct venting emissions as a possible GHG control measure. This option is technically feasible and was evaluated by BPH for Coker 3 based on the modifications occurring as part of the TFO project.

BPH already routinely depressures to less than 5 psig before opening the atmospheric vent on Coker 3. Depressuring further to 2 psig before venting would result in even less emissions. BPH understands that several refineries already operate with a 2 psig vent pressure limit. Therefore, BACT is proposed as venting to the blowdown recovery system until the coke drums are depressured to no more than 2.0 psig. Compliance will be demonstrated through recording the pressure prior to coke drum vent opening to the atmosphere.

## E.5 Fugitive Emissions GHG BACT Analysis (Coker 3 Unit (P036))

Small leaks from the piping connectors and the stem packing of valves can be sources of fugitive GHG emissions for equipment containing $CH_4$. The new piping components of the modified Coker gas plant and any new natural gas piping in the Coker 3 unit will contain $CH_4$. These piping components are designed not to leak, but statistically, a few leaks are expected to occur from time to time. As required by multiple regulations, all new VOC fugitive emission components will be integrated into the BP-Husky Leak Detection and Repair (LDAR) program. This program is designed to comply with applicable NSPS Subpart GGGa and Refinery MACT (Subpart CC) standards. The LDAR program promptly identifies leaking components through regular monitoring and institutes a schedule for the repair.

For the piping, such as the refinery fuel gas piping in the new piping of the modified coker gas plant which contains significant $CH_4$, these VOC LDAR regulations will serve to help control GHG emissions as well. BPH further proposes to extend the

10 *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, US EPA Office of Air and Radiation, October 2010.

use of the existing refinery LDAR program to also include any new natural gas piping installed by this project in the modified process Coker 3 process unit (P036). Natural gas, which is predominately $CH_4$, is not a VOC, so it would not otherwise be required to be included in the LDAR plan.

Such an LDAR program is a technically feasible method of controlling $CH_4$ emissions from equipment leaks. The fugitive GHG emissions after employment of these control practices are extremely small.

Therefore, compliance with the applicable NSPS GGGa and Refinery MACT (CC) LDAR regulations is proposed as BACT for fugitive GHG ($CH_4$) emissions from new piping components. Likewise, any new natural gas piping in the Coker 3 unit is proposed to be included in the refinery LDAR program.