**Statement of Basis**
Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the M&G Resins USA, L.L.C., Utility Plant

Permit Number: PSD-TX-1354-GHG

This document serves as the Statement of Basis (SOB) 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

In February 2013, two separate companies, M&G Resins USA LLC (M&G Resins), and NRG Development Company, Inc (NRG) each notified the EPA and the Texas Commission on Environmental Quality (TCEQ) by way of Prevention of Significant Deterioration (PSD) permit application submittals that they were planning to develop a common greenfield location near Corpus Christ; Nueces County, Texas into a new chemical process plant with a utility support facility that will together constitute a major stationary source for new source review purposes. See 40 CFR 52.21(b)(5), (6). M&G Resins planned to build a new resin manufacturing complex (or, the PET Plant, from "polyethylene terephthalate") while NRG intended to build a collocated combined heat and power utility plant (the Utility Plant) to exclusively serve the steam and electrical demands of M&G Resins' PET plant. The entire project bears the label "Project Jumbo." In March of 2014, M&G Resins acquired ownership of the Utility Plant from NRG and revised the Utility Plant permit application to authorize two optional plant configurations: Option 1: the construction of the combined heat and power plant as originally proposed by NRG, or Option 2: the construction of boiler facilities to provide steam but not to provide power. The company would be obligated to select only one of the two mutually exclusive options under which to construct and operate. Notably, in the Option 2 configuration, the Utility Plant would not be regulated under the proposed action, "Greenhouse Gas Emissions from New Stationary Sources: Generating Units", (79 FR 1430, January 8, 2014), because it would not meet the applicability criteria set forth in that proposal. Under Option 1, the gas turbine would potentially meet the applicability criteria for size under the proposed 40 CFR 60 KKKK, and would by its design meet the Best System of Emissions Reductions by the nature of the proposed facility, by operating at a rate well below the standard required.[1] However, the company is not planning to sell power to the grid, therefore, the source is not subject to the proposed KKKK.[2]

While these two plants, the PET plant and the Utility Plant, together constitute a single stationary source for PSD purposes, the applicant requests that the applicable requirements for the Best

[1] Specifically, M&G Resins LLC would be subject to the proposed NSPS Subpart KKKK and would meet the 1000 lb/MWh limit as found in Table 2 of 40 CFR § 60.4326, as the estimated emissions, calculated in accordance with the relevant proposed KKKK methodology, would equal 682.4 lb/MWh without duct firing, and would equal 603.4 lb/MWh with duct burner firing, both turbine and duct burners firing natural gas.

[2] The company represents that under Option 1, it will not meet the criteria of the proposed (79 FR 1430) 40 CFR § 60.4305(c)(5), which reads "(5) Was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a 3 year rolling average basis."

Available Control Technology (BACT) be addressed through separate proposed PSD permits. Consistent with the state-submitted PSD permit applications, TCEQ is similarly proposing separate PSD permits to address all non-GHG pollutants. This SOB addresses the PSD requirements and associated terms and conditions for GHG emissions from emissions units at the proposed Utility Plant. GHG emissions from the PET plant are addressed via the separately proposed PSD permit PSD-TX-1352-GHG and its supporting statement of basis. While the analysis of Carbon Capture and Storage (CCS) considers the major emitting units for the site as a whole (as part of a logical grouping of emission units), this SOB otherwise conducts a BACT review only for the emissions attributable to Utility Plant emissions units and operations. The SOB for the proposed PET plant PSD permit should be consulted for the full BACT review that applies to PET plant emissions and emissions units.

The TCEQ is currently developing the combined PSD and minor source permit (PSD-TX-1354/108819, respectively) for criteria pollutants from the proposed Utility Plant.

After reviewing the application, EPA Region 6 has prepared the following statement of basis and a draft air permit to apply GHG PSD requirements to the construction of the Utility Plant.

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 will comply with the requirements.

EPA Region 6 concludes that M&G's 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 M&G, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

## II. Applicant

M & G Resins USA, L.L.C.
450 Gears Rd Ste 240
Houston, Texas 77067-4513

Facility Physical Address:
M&G Resins USA, LLC Utility Plant
7001 Joe Fulton International Trade Corridor, Suite 200
Corpus Christi, Texas 78409

Technical Contact:
Ms. Allana Whitney, Project Manager – Chemtex International Inc. (910) 509-4451

## III. Permitting Authority

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

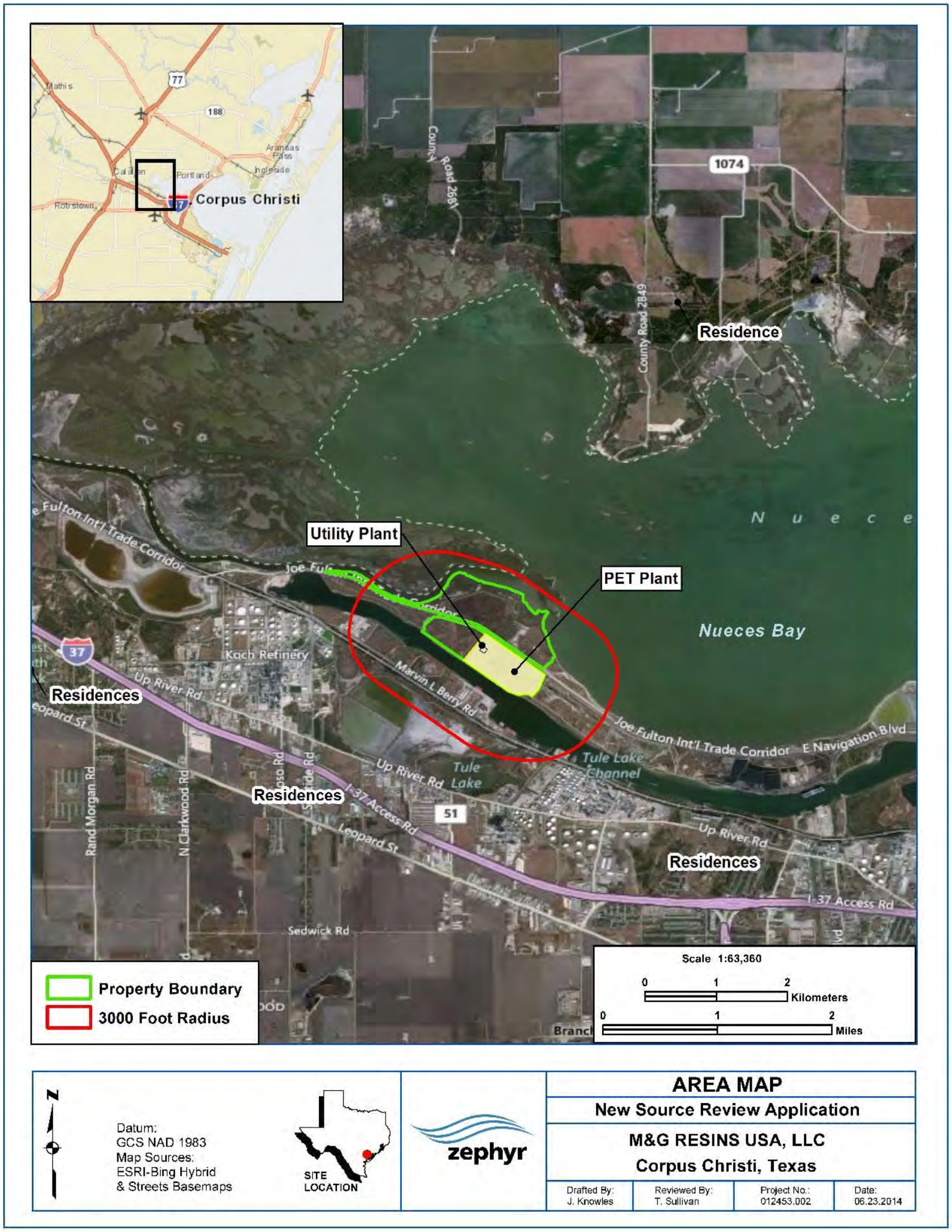
The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:

Brad Toups
Air Permitting Section (6PD-R)
1445 Ross Avenue
Dallas, TX 75202
(214) 665-7258

## IV. Facility Location



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

EPA Region 6 implements a GHG PSD FIP for the State of Texas under the provisions of 40 CFR 52.21 (except paragraph (a)(1)). *See* 40 CFR § 52.2305. On June 23, 2014, the United States Supreme Court issued a decision addressing the application of stationary source permitting requirements to greenhouse gases (GHG). *Utility Air Regulatory Group (UARG) v. Environmental Protection Agency* (EPA) (No. 12-1146). The Supreme Court said that the EPA may not treat greenhouse gases as an air pollutant for purposes of determining whether a source is a major source required to obtain a Prevention of Significant Deterioration (PSD) or title V permit. However, the Court also said that the EPA could continue to require that PSD permits, otherwise required based on emissions of conventional pollutants, contain limitations on GHG emissions based on the application of Best Available Control Technology (BACT). Pending further EPA engagement in the ongoing judicial process before the District of Columbia Circuit Court of Appeals, the EPA is proposing to issue this permit consistent with EPA's understanding of the Court's decision.

The source will constitute a new major source because the facility (a chemical process plant under 40 CFR 52.21(b)(1)(i)(a) with an accompanying support facility) has the potential to emit more than 100 tons per year of CO and VOC. (The applicant has estimated approximately 350 tpy VOC, and greater than 500 tpy CO for the entire project [3].) In this case, the applicant represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, will determine the project is subject to PSD review for these pollutants as well as any other regulated NSR pollutants determined to equal or exceed the rates set forth in 40 CFR 52.21(b)(23).

The applicant also estimates that this same project emits or has the potential to emit in excess of 1,000,000 tpy $CO_2e$ of GHGs, which well exceeds the 75,000 ton per year $CO_2e$ threshold in EPA regulations. 40 C.F.R § (49)(iv); *see also, PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) at 12-13). Since the Supreme Court recognized EPA's authority to limit application of BACT to sources that emit GHGs in greater than *de minimis* amounts, EPA believes it may apply the 75,000 tons per year threshold in existing regulations at this time to determine whether BACT applies to GHGs at this facility.

Accordingly, this project continues to require a PSD permit that includes limitations on GHG emissions based on application of BACT. The Supreme Court's decision does not materially limit the FIP authority and responsibility of Region 6 with regard to this particular permitting action. Accordingly, under the circumstances of this project, the TCEQ will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[4]

EPA Region 6 proposes to follow the policies and practices reflected in EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011). For the reasons described in that

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[3] It is anticipated that the PET State/PSD permit for criteria pollutants for PET Plant will be proposed as State/PSD permit 108446/PSD-TX-1352 while the State/PSD permit for criteria pollutants from the Utility plant will be proposed as permit 108819/PSD-TX-1354.

[4] 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

guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA believes that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the 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 M&G to construct the new Utility plant, The new Utility plant will be located at M&G's site as previously described.

The Utility Plant will account for between 58 and 63% of the sitewide emissions, based on the final selection of Option 1, a Combined Heat and Power (CHP) Plant (generate electricity and steam in the Utility Plant) or Option 2, purchase electricity and only generate steam in the Utility Plant. The estimated sitewide emissions are as follows:

**Table 1. Sitewide GHG Emissions Summary (tpy)**

| GHG[1] | Sitewide Total GHG with Utility Plant Option 1 | | | Sitewide Total GHG with Utility Plant Option 2 | | |
|---|---|---|---|---|---|---|
| | PET Plant | Utility Plant | Total | PET Plant | Utility Plant | Total |
| $CO_2$ | 432,946 | 738,926 | 1,171,872 | 432,946 | 622,555 | 1,055,501 |
| $CH_4$ | 193 | 34 | 227 | 193 | 32 | 225 |
| $N_2O$ | 2 | 1 | 3 | 2 | 1 | 3 |
| $CO_2e$ | 438,367 | 740,074 | 1,178,441 | 438,367 | 623,653 | 1,062,020 |
| % of Total → | 37.20% | 62.80% | | 41.28% | 58.72% | |

1. $CO_2e$ emissions are calculated by multiplying the mass emissions rate of each GHG constituent by the global warming potential value, as published in 40 CFR Part 98. The current values are $CO_2$=1, $CH_4$=25, and $N_2O$=298.

While Option 2 if chosen would have the lower GHG emissions for the site, Option 2 would require power purchased from the grid. Power generation offsite would also create GHG emissions, but those emissions would not be accounted for in this project as it is not possible to identify the particular location where the necessary electrical generation would take place for use by the facility.

While the above table depicts GHG emissions sitewide, Tables 1a, below, show the estimated emissions for the PET plant broken down by emissions unit, while Tables 1b and 1c show the GHG emissions for the two options for the Utility Plant.

The Utility Plant will provide steam to M&G Resins' new polyethylene terephthalate (PET) Plant and new terephthalic acid (PTA) unit located on the same site. Power will also be supplied by the CHP plant, if constructed.

The new CHP plant (Option 1) will generate approximately 49 megawatts (MW) of gross electrical power in addition to high and low pressure steam for use in the PET plant. Power generating equipment, as well as ancillary equipment, is listed below:

- One General Electric LM6000 natural gas-fired combustion turbine equipped with lean pre-mix low-$NO_x$ combustors
- One heat recovery steam generator (HRSG) with 263 million British thermal units per hour (MMBtu/hr) natural gas-fired duct burner system containing a selective catalytic reduction system (SCR)
- One 445 MMBtu/hr natural gas-fired boiler (Auxiliary Boiler A1)
- One 250 MMBtu/hr natural gas-fired boiler (Auxiliary Boiler B)
- Natural gas venting
- Natural gas piping and metering

The three Auxiliary Boilers (Option 2) will produce high and low pressure steam for use in the PET plant. Boilers, as well as ancillary equipment, are listed below:

- One 445 MMBtu/hr natural gas-fired boiler (Auxiliary Boiler A1)
- One 445 MMBtu/hr natural gas-fired boiler (Auxiliary Boiler A2)
- One 250 MMBtu/hr natural gas-fired boiler (Auxiliary Boiler B)
- Natural gas venting
- Natural gas piping and metering

While not falling under the terms and conditions of the proposed Utility Plant Permit, the following emissions units are part of the PET Plant:

- Four process heaters (EPNs: E7-A thru E7-D, approximately 28% of sitewide $CO_2e$ emissions)
- Two regenerative thermal oxidizers (RTOs, EPNs: E1, E2, approximately 12% of sitewide $CO_2e$ emissions)
- A Biogas Flare (EPN: Flare, approximately 1% of sitewide $CO_2e$ emissions)
- Two diesel fuel-fired emergency electrical generator engines (EPNs: E85-A, E85-B)
- Two diesel fuel-fired fire water pump engines (EPNs: E87-A, E87-B)
- Piping fugitives (EPNs: FUGPTA, FUGPET)

The contribution of GHG to the site wide totals by the various emissions units are depicted in Tables 1a, 1b, and 1c, below.

| Table 1a. M&G PET Plant Annual Emissions and BACT Summary | | | | | | | $CO_2$ Mass Emissions | | |
|---|---|---|---|---|---|---|---|---|---|
| FIN | EPN | Description | GHG Mass Basis: GHG | GHG Mass Basis: TPY | TPY $CO_2e$ | BACT Requirements | of Site | | of Plant |
| E7-A | E7-A | Heat Transfer Fluid (HTF) Heater-On Nat.Gas | $CO_2$ | 72,622 | 72,622 | Limit the exhaust gas temperature from the HTF Heaters to 320°F. See permit condition III.A.6 | 300,069 | | 290,488 |
| | | | $CH_4$ | 1.37 | 34.25 | | 25.6% | of Opt 1 | 67.1% |
| | | | $N_2O$ | 0.14 | 41.72 | | 28.4% | of Opt 2 | |
| E7-B | E7-B | Heat Transfer Fluid (HTF) Heater-On Nat.Gas | $CO_2$ | 72,622 | 72,622 | Limit the exhaust gas temperature from the HTF Heaters to 320°F. See permit condition III.A.6 | | | |
| | | | $CH_4$ | 1.37 | 34.25 | | | | |
| | | | $N_2O$ | 0.14 | 41.72 | | | | |
| E7-C | E7-C | Heat Transfer Fluid (HTF) Heater-On Nat.Gas | $CO_2$ | 72,622 | 72,622 | Limit the exhaust gas temperature from the HTF Heaters to 320°F. See permit condition III.A.6 | | | |
| | | | $CH_4$ | 1.37 | 34.25 | | | | |
| | | | $N_2O$ | 0.14 | 41.72 | | | | |
| E7-D | E7-D | Heat Transfer Fluid (HTF) Heater-On Nat.Gas | $CO_2$ | 72,622 | 72,622 | Limit the exhaust gas temperature from the HTF Heaters to 320°F. See permit condition III.A.6 | | | |
| | | | $CH_4$ | 1.37 | 34.25 | | | | |
| | | | $N_2O$ | 0.14 | 41.72 | | | | |
| E7-A to D [1] | E7-A to D | Heat Transfer Fluid (HTF) Heaters-On Fuel Gas (3) | $CO_2$ | 9,581 | 9,581 | Limit the exhaust gas temperature from the HTF Heaters to 320°F. See permit condition III.A.6 | | | |
| | | | $CH_4$ | 0.21 | 5.13 | | | | |
| | | | $N_2O$ | 0.02 | 6.26 | | | | |
| E1 [3] | E1 | Regenerative Thermal Oxidizer 1 (RTO1)-On Waste Gas (4) | $CO_2$ | 54,495 | 54,495 | Maintain a minimum combustion temperature as determined by initial compliance testing. See permit condition III.C. | 127,196 | | 108,990 |
| | | | $CH_4$ | 83 | 2,075 | | 10.9% | of Opt 1 | 25.2% |
| | | | $N_2O$ | 0.54 | 160.92 | | 12.1% | of Opt 2 | |
| | | Regenerative Thermal Oxidizer 1 (RTO1)-On Nat.Gas | $CO_2$ | 9,103 | 9,103 | Maintain a minimum combustion temperature as determined by initial compliance testing. See permit condition III.C. | | | |
| | | | $CH_4$ | 0.17 | 4.25 | | | | |
| | | | $N_2O$ | 0.02 | 5.96 | | | | |
| E2 [3] | E2 | Regenerative Thermal Oxidizer 2 (RTO2)-On WasteGas (4) | $CO_2$ | 54,495 | 54,495 | Maintain a minimum combustion temperature as determined by initial compliance testing. See permit condition III.C. | | | |
| | | | $CH_4$ | 83 | 2,075 | | | | |
| | | | $N_2O$ | 0.54 | 160.92 | | | | |
| | | Regenerative Thermal Oxidizer 2 (RTO2)-On Nat.Gas | $CO_2$ | 9,103 | 9,103 | Maintain a minimum combustion temperature as determined by initial compliance testing. See permit condition III.C. | | | |
| | | | $CH_4$ | 0.17 | 4.25 | | | | |
| | | | $N_2O$ | 0.02 | 5.96 | | | | |
| FLARE [2] | FLARE | Biogas Flare-Flaring Biogas and including nat gas pilot | $CO_2$ | 8,942 | 8,942 | Good combustion and maintenance practices. See permit condition III.B | 8,942 | | 8,942 |
| | | | $CH_4$ | 13.60 | 340.00 | | 0.8% | of Opt 1 | 2.1% |
| | | | $N_2O$ | 0.09 | 26.52 | | 0.8% | of Opt 2 | |
| | | Biogas Flare-On Nat.Gas for flare pilot | $CO_2$ | 31 | 31 | Good combustion and maintenance practices. See permit condition III.B | | | |
| | | | $CH_4$ | 5.89E-04 | 0.01 | | | | |
| | | | $N_2O$ | 5.89E-05 | 0.02 | | | | |
| E85-A | E85-A | Emergency Diesel Generator | $CO_2$ | 2,577 | 2,577 | Low annual capacity factor and annual routine maintenance as prescribed by NSPS. See permit condition III.D. | 5,650 | | 5,650 |
| | | | $CH_4$ | 0.1 | 2.5 | | 0.5% | of Opt 1 | 1.3% |
| | | | $N_2O$ | 0.02 | 5.96 | | 0.5% | of Opt 2 | |
| E85-B | E85-B | Emergency Diesel Generator | $CO_2$ | 2,577 | 2,577 | Low annual capacity factor and annual routine maintenance as prescribed by NSPS. See permit condition III.D. | | | |
| | | | $CH_4$ | 0.1 | 2.5 | | | | |
| | | | $N_2O$ | 0.02 | 5.96 | | | | |
| E87-A | E87-A | Fire Water Pump Diesel Generator | $CO_2$ | 248 | 248 | Low annual capacity factor and annual routine maintenance as prescribed by NSPS. See permit condition III.E. | 689 | | 689 |
| | | | $CH_4$ | 0.01 | 0.25 | | 0.1% | of Opt 1 | 0.2% |
| | | | $N_2O$ | 0.002 | 0.596 | | 0.1% | of Opt 2 | |
| E87-B | E87-B | Fire Water Pump Diesel Generator | $CO_2$ | 248 | 248 | Low annual capacity factor and annual routine maintenance as prescribed by NSPS. See permit condition III.E. | | | |
| | | | $CH_4$ | 0.01 | 0.25 | | | | |
| | | | $N_2O$ | 0.002 | 0.596 | | | | |
| FUGPTA | FUGPTA | Combined Plant Fugitives | $CO_2$ | 0.72 | 0.72 | Implementation of LDAR/AVO program. See permit condition III.F. | 193 | | 193 |
| FUGPET | FUGPET | | $CH_4$ | 20.27 | 506.75 | | 0.0% | of Opt 1 | 0.0% |
| **Totals** | | | **$CO_2$** | **432,946** | **$CO_2e$** | | | | |
| | | | **$CH_4$** | **193** | **438,273** | | | | |
| | | | **$N_2O$** | **2** | | | | | |

Notes:

1 Biogas is normally routed to any of the four heaters simultaneously, or to the flare, but not to both the flare and heaters concurrently. The emissions for the heaters include the maximum contribution of bio gas which offsets heater natural gas use.

2 Waste gas may be routed to the flare, but if so, won't be routed to any heater. Monitoring provisions assure compliance. Therefore, the Biogas Flaring is omitted from the total.

3 RTOs use natural gas for startup and supplementally as needed to maintain proper operating temperature but the heating value necessary to properly operate the RTO normally is supplied by the waste gas being treated by the RTO, therefore the emissions attributable to waste gas include the natural gas supplementally fired.

4 Natural Gas can and will be fired concurrently with waste gas in the RTO to maintain proper operating conditions.

**Table 1b M&G Project Jumbo GHG Emissions- Utility Plant**

**Utility Plant: Option 1**

| FIN | EPN | Description | GHG Mass Basis | | TPY $CO_2e$ | BACT Requirements | $CO_2$ Mass Emissions | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | GHG | TPY[2] | | | of Site | | of Plant |
| CTG | CTG | General Electric LM6000 CT with 245 MMBtu/hr Duct Burner and HRSG | $CO_2$ | 363,652 | 363,652 | Minimum Thermal Efficiency of 60% (LHV basis). See Special Condition III.E.1. and 2. | 363,652 | | 363,652 |
| | | | $CH_4$ | 6.86 | 171.50 | | 31.0% | | 49.2% |
| | | | $N_2O$ | 0.69 | 205.62 | | | | |
| AUXBLRA1 | AUXBLRA1 | Auxiliary Boiler A1 | $CO_2$ | 247,281 | 247,281 | Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2. | 247,281 | | 247,281 |
| | | | $CH_4$ | 4.66 | 116.50 | | 21.1% | | 33.5% |
| | | | $N_2O$ | 0.47 | 140.06 | | | | |
| AUXBLRB | AUXBLRB | Auxiliary Boiler B | $CO_2$ | 127,992 | 127,992 | Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2. | 127,992 | | 127,992 |
| | | | $CH_4$ | 2.41 | 60.25 | | 10.9% | | 17.3% |
| | | | $N_2O$ | 0.24 | 71.52 | | | | |
| NG-FUG | NG-FUG | Natural Gas Fugitives | $CO_2$ | 1 | 1 | Implementation of AVO monitoring program. See Special Condition III.I.1. and 2. | | | |
| | | | $CH_4$ | 20.27 | 506.75 | | | | |
| | | | $N_2O$ | | | | | | |
| MSS-FUG | MSS-FUG | MSS Natural Gas Venting | $CO_2$ | 0 | 0 | Implementation of AVO monitoring program. See Special Condition III.I.1. and 2. | | | |
| | | | $CH_4$ | 0.106 | 2.65 | | | | |
| | | | $N_2O$ | | | | | | |
| **Totals** | | | **$CO_2$** | **738,926** | **$CO_2e$** | **62.8% of sitewide emissions** | | | |
| | | | **$CH_4$** | **34.3** | **740,201** | | | | |
| | | | **$N_2O$** | **1.4** | | | | | |

**Table 1c M&G Project Jumbo GHG Emissions- Utility Plant**

**Utility Plant: Option 2**

| FIN | EPN | Description | GHG Mass Basis | | TPY $CO_2e$ | BACT Requirements | $CO_2$ Mass Emissions | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | GHG | TPY[2] | | | of Site | | of Plant |
| AUXBLRA1 | AUXBLRA1 | Auxiliary Boiler A1 | $CO_2$ | 247,281 | 247,281 | Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2. | 494,562 | | 494,562 |
| | | | $CH_4$ | 4.66 | 116.50 | | 46.9% | | 79.4% |
| | | | $N_2O$ | 0.47 | 140.06 | | | | |
| AUXBLRA2 | AUXBLRA2 | Auxiliary Boiler A2 | $CO_2$ | 247,281 | 247,281 | Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2. | | | |
| | | | $CH_4$ | 4.66 | 116.50 | | | | |
| | | | $N_2O$ | 0.47 | 140.06 | | | | |
| AUXBLRB | AUXBLRB | Auxiliary Boiler B | $CO_2$ | 127,992 | 127,992 | Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2. | 127,992 | | 127,992 |
| | | | $CH_4$ | 2.41 | 60.25 | | 12.1% | | 20.6% |
| | | | $N_2O$ | 0.24 | 71.52 | | | | |
| NG-FUG | NG-FUG | Natural Gas Fugitives | $CO_2$ | 1 | 1 | Implementation of AVO monitoring program. See Special Condition III.I.1. and 2. | | | |
| | | | $CH_4$ | 20.27 | 506.75 | | | | |
| | | | $N_2O$ | | | | | | |
| MSS-FUG | MSS-FUG | MSS Natural Gas Venting | $CO_2$ | 0 | 0 | Implementation of AVO monitoring program. See Special Condition III.I.1. and 2. | | | |
| | | | $CH_4$ | 0.106 | 2.65 | | | | |
| | | | $N_2O$ | | | | | | |
| **Totals** | | | **$CO_2$** | **622,555** | **$CO_2e$** | **58.7% of sitewide emissions** | | | |
| | | | **$CH_4$** | **32.1** | **623,709** | | | | |
| | | | **$N_2O$** | **1.2** | | | | | |

As discussed previously, this SOB addresses the emissions units that are part of the Utility Plant. The PET Plant authorization basis and requirements are found in the companion PET Plant permit. The PET Plant emissions are shown for sitewide completeness.

## 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 available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control options;
(4) Evaluate the most effective controls (taking into account the energy, environmental, and economic impacts) and document the results; and
(5) Select BACT.

## VIII. Applicable Emission Units and BACT Discussion

As can be seen by reviewing the data in Tables 1.a, 1.b and 1.c, above the majority of the contribution of GHGs associated with the project, and indeed, from the site, is from combustion sources (i.e., combustion turbine, duct burners, and boilers). The project has some fugitive emissions from piping components which contribute a relatively insignificant amount of GHGs. Fugitive emissions account for 20 TPY of $CO_2e$, or less than 0.01% of the project's total $CO_2e$ emissions. Stationary combustion sources primarily emit $CO_2$, and small amounts of $N_2O$ and $CH_4$. The following equipment at the site are subject to this GHG PSD permit:

**Option 1 (CHP Facility) Equipment**

| FIN | EPN | Description |
|---|---|---|
| CTG | CTG | Natural Gas-Fired General Electric LM6000 Combustion Turbine. The unit has a nominal base-load gross electric power output of approximately 49 MW vented to a 263 MMBtu/hr duct-fired HRSG for steam generation (Combustion Unit). The Combustion Unit is equipped with SCR and exhausts through a single flue gas stack. |
| AUXBLRA1 | AUXBLRA1 | Natural Gas-Fired Boiler. The unit has a maximum heat input capacity of 445 MMBtu/hr. |
| AUXBLRB | AUXBLRB | Natural Gas-Fired Boiler. The unit has a maximum heat input capacity of 250 MMBtu/hr. |
| NG-FUG | NG-FUG | Natural Gas Piping and Metering Equipment Leak Components. |
| MSS-FUG | MSS-FUG | Natural Gas Venting related to Turbine Startup and Shutdown and Equipment Maintenance. |

**Option 2 (Three Auxiliary Boilers) Equipment**

| FIN | EPN | Description |
|---|---|---|
| AUXBLRA1 | AUXBLRA1 | Natural Gas-Fired Boiler. The unit has a maximum heat input capacity of 445 MMBtu/hr. |
| AUXBLRA2 | AUXBLRA2 | Natural Gas-Fired Boiler. The unit has a maximum heat input capacity of 445 MMBtu/hr. |
| AUXBLRB | AUXBLRB | Natural Gas-Fired Boiler. The unit has a maximum heat input capacity of 250 MMBtu/hr. |
| NG-FUG | NG-FUG | Natural Gas Piping and Metering Equipment Leak Components. |
| MSS-FUG | MSS-FUG | Natural Gas Venting related Startup and Shutdown and Equipment Maintenance. |

Project Jumbo is comprised on the PET Plant and the Utility Plant. Because both plants will share an evaluation of the control of GHG emissions, particularly for CCS, the reference to the GHG sources of the PET plant is provided here. As stated previously, the following GHG sources are part of the PET Plant, and their emissions, controls, and limitations are fully detailed in the Statement of Basis and proposed permit PSD-TX-1352-GHG:

- Heat Transfer Fluid (HTF) Heaters 1-4 (EPNs: E7-A, E7-B, E7-C, E7-D)
- Biogas Flare (EPN: Flare)
- Regenerative Thermal Oxidizers (RTOs) 1 and 2 (EPNs: E1, E2)
- Emergency Diesel Generators 1 and 2 (EPNs: E85-A, E85-B)
- Fire Water Pump Diesel Engines 1 and 2 (EPNs: E87-A, E87-B)
- Plant Fugitives (EPNs: FUGPTA and FUGPET)

**BACT Analysis for Combustion Turbine (Option 1 EPN: CTG)**

The combustion turbine and steam generator proposed by M&G Resins under this option is being installed in a combined heat and power (CHP) configuration. The turbine will utilize a high efficiency aeroderivative design. It will be equipped with a dry low-NOx burner (DLNB). The combustion turbine will burn pipeline natural gas to rotate an electrical generator to generate electricity. The main components of a combustion turbine generator consist of a compressor, combustor, turbine, and generator. The compressor pressurizes combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the turbine where the gases expand across the turbine blades, driving a shaft to power an electric generator. The exhaust gas will exit the combustion turbine and be routed to the HRSG for steam production.

Heat recovered in the HRSG will be utilized to produce steam. Steam generated within the HRSG will be supplied to the PET plant. The HRSG will be equipped with duct burners for supplemental steam production. The duct burners will be fired with pipeline-quality natural gas. The duct burners have a maximum heat input capacity of 263 MMBtu/hr per unit. The exhaust gases from the unit, including emissions from the CT and the duct burners, will exit through a stack to the atmosphere after passing through a Selective Catalytic Reduction (SCR) system and an Oxidation Catalyst (Ox-Cat). The DNLB and SCR are used to reduce NOx emissions while Ox-Cat is used to reduce CO and VOC emissions.

**Step 1: Identification of Potential Control Technologies for GHGs**

1. Carbon Capture and Storage (CCS) – CCS is an available add-on control technology that is applicable for all of the site's combustion units. Comparatively, $CO_2$ emissions contribute the most volume (greater than 99%) to the overall emissions; therefore, additional analysis is not required for $CH_4$ and $N_2O$.

2. Efficient Combustion Turbine Design – The turbine will utilize a high efficiency aeroderivative design. The combustion turbine and steam generator is being installed in a combined heat and power (CHP) configuration.

3. Instrumentation and Controls– The turbine will use sophisticated instrumentation and controls to automatically control the operation of the combustion turbine.

4. Waste Heat Recovery – Hot turbine exhaust gases are routed through a natural gas fired duct burners of the HRSG to produce steam that is used elsewhere in lieu of installing another fired boiler. The HRSG is designed to maximize heat transfer.

5. Minimizing Fouling of Heat Exchange Surfaces - To minimize fouling, filtration of the inlet air to the combustion turbine is performed. Additionally, cleaning of the tubes is performed during periodic outages.

**Step 2: Elimination of Technically Infeasible Alternatives**

All options identified in Step 1 are considered technically feasible for this project.

1. Carbon Capture and Sequestration (CCS). Carbon capture and sequestration is a GHG 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)."[5]

   CSS $CO_2$ Capture: CCS systems involve the use of adsorption or absorption processes to 'capture' or remove $CO_2$ from flue gas, with subsequent desorption to produce a

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

concentrated $CO_2$ stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion. 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. 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. Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for the proposed facility.[6]

The third approach, post-combustion capture, is applicable to combustion turbines and may be applicable to other combustion sources. With respect to post-combustion capture, a number of methods may potentially be used for separating the $CO_2$ from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation. Many of these methods are either still in development or are not suitable for treating power plant flue gas due to the characteristics of the exhaust stream.

Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes.[7]

In a typical MEA absorption process, the flue gas is cooled before it is contacted counter-currently with the lean solvent in a reactor vessel. The scrubbed flue gas is cleaned of solvent and vented to the atmosphere while the rich solvent is sent to a separate stripper where it is regenerated at elevated temperatures and then returned to the absorber for re-use. Fluor's Econamine FG Plus process operates in this manner, and it uses an MEA-based solvent that has been specially designed to recover $CO_2$ from oxygen-containing streams with low $CO_2$ concentrations typical of gas turbine exhaust.[8] Notwithstanding demonstration projects are at various stages of planning and implementation, there are apparently no commercial applications of this technology for CCS at the present time on sources similar to M&G combustion sources.

<u>CCS: Compression and Transport.</u> Once separated from the flue gas stream, the $CO_2$ will need to be transported to its ultimate storage location. Unless the final storage location is nearby, the efficient transportation of a $CO_2$ stream will require that the stream

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[6] Wang, M., Lawal, A., Stephenson, P., Sidders, J., & Ramshaw, C. (2011). Post-combustion CO2 capture with chemical absorption: A state-of-the-art review. Chemical Engineering Research and Design, 89, 1609-1624.

[7] Kvamsdal, H., Chikukwa, A., Hillestad, M., Zakeri, A., & Einbu, A. (2011). A comparison of different parameter correlation models and the validation of an MEA-based absorber model. Energy Procedia, 4, 1526-1533

[8] Fluor Corporation. (2009). Econamine FG Plus Process. Available here: http://www.fluor.com/econamine/Pages/efgprocess.aspx. Last visited September 24, 2014.

be compressed to the supercritical fluid state for transportation in high pressure pipeline.[9] While energy and resource intensive, obtaining right-of-way, constructing, and operating such a pipeline is technically possible. While there are many factors that enter into the cost and operation of such a pipeline, the final cost of such a pipeline is directly related to its size and length.[10]

<u>CCS Sequestration:</u> Specific types of geologic formations capable of receiving and permanently storing $CO_2$ are the target long term storage reservoirs for $CO_2$ streams. $CO_2$ floods have been used in enhanced oil recovery (EOR) operations for decades. Essentially EOR operations inject $CO_2$ under pressure through multiple injection wells in an existing suitable oil field producing zone. When injected, the $CO_2$ aids in the flow of oil to producing oil wells that are located on the other end of the oil field area. $CO_2$ recovered with the produced oil is then recirculated back to the injection wells for reinjection. Such geologic formations have characteristics that allow the $CO_2$ to remain in the oil field producing zone for extended periods of time, and perhaps permanently. Multiple studies are underway to characterize the suitability of potential sequestration sites in various locations within Texas and in the Southeast. The Gulf Coast Carbon Center, a part of the Bureau of Economic Geology in Texas is one such organization currently involved in site characterization at various locations in Texas.

While no South and Southeast Texas EOR reservoirs or other nearby geologic formations have yet been technically demonstrated to be suitable for large-scale, long-term $CO_2$ storage, the W.A. Parish Post Combustion $CO_2$ Capture and Sequestration Project, funded partially by the Department of Energy, is proposing to use $CO_2$ captured from an exhaust stream from a 250 MW turbine (Unit 8 of the W.A Parish Plant in Fort Bend county, TX) as part of an Enhanced Oil Recovery (EOR) project at the Existing West Ranch oil field in Jackson County. The West Ranch field is located approximately 100 miles northeast of Corpus Christi, near Vanderbilt, Tx.

Other locations are currently being studied as potentially long term sequestration sites for anthropomorphic $CO_2$. The US. Department of Energy has identified the Stacked Storage location in the Cranfield Field Site in Mississippi as one such location. In comparison, the closest site that is currently being field-tested to demonstrate its capacity for large-scale geological storage of $CO_2$ is the Southwest Regional Partnership (SWP) on Carbon Sequestration's Scurry Area Canyon Reef Operators (SACROC) test site, which is located in Scurry County, Texas. According to M&G Resins, the shortest pipeline distance to the SACROC facility is 441 miles from the M&G site.

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[9] The U.S. Department of Energy's National Energy Technology Laboratory webpage on $CO_2$ Compression. http://www.netl.doe.gov/research/coal/carbon-capture/co2-compression (last visited September 24, 2014)

[10] Carbon Dioxide Transport and Storage Costs in NETL Studies. DOE/NETL-2013/1614. Final Report March 14, 2013 available here: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/QGESS_CO2T-S_Rev2_20130408.pdf

While there are some potential long term sequestration sites, none have been demonstrated as available for commercial use.

CCS overall. While elements of CCS are currently available for commercial use, the technology as a whole has not been demonstrated to be commercially available for use with a project similar to the M&G project. Nevertheless, we do not eliminate the technology entirely on technical grounds; rather, M&G has provided cost and other considerations on implementation of CCS for the combustion sources at the M&G project as a whole, and those will be discussed in Step 4.

It should be noted, that while this project is not entirely comprised of electrical generation, it does have an electrical generation using a gas turbine component. EPA's recent proposed rule addressing Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units concluded that CCS was not the best system of emission reduction for a nation-wide standard for natural gas combined-cycle (NGCC) turbines based on questions about whether full or partial capture CCS is technically feasible for the NGCC source category.[11]

While recognizing that the combustion turbine generator would potentially be responsible for only approximately 30% of the GHG from the project, EPA is evaluating whether there is sufficient information to conclude that CCS is technically feasible at this specific NGCC source and will consider public comments on this issue. However, because the applicant has provided a basis to eliminate CCS on other grounds, we have assumed, for purposes of this specific permitting action, that potential technical or logistical barriers do not make CCS technically infeasible for this project and have addressed the economic feasibility issues in Step 4 of the BACT analysis in order to assess whether CCS is BACT for this project.

2. Efficient Combustion Turbine Design – The turbine will utilize a high efficiency aeroderivative design. The combustion turbine and steam generator is being installed in a combined heat and power (CHP) configuration. This is available technology.

3. Instrumentation and Controls– The turbine will use sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. This is available technology.

4. Waste Heat Recovery – Hot turbine exhaust gases are routed through a natural gas fired duct burners of the HRSG to produce steam that is used elsewhere in lieu of installing another fired boiler. The HRSG is designed to maximize heat transfer. This is available technology.

5. Minimizing Fouling of Heat Exchange Surfaces - To minimize fouling, filtration of the inlet air to the combustion turbine is performed. Additionally, cleaning of the tubes is

[11] 79 Fed. Reg. 1430, 1485 (Jan. 8, 2014)

performed during periodic outages. This is available operation and maintenance technology.

**Step 3: Ranking of Remaining Technologies Based on Effectiveness**

1. Carbon Capture and Storage (CCS)
2. Efficient Combustion Turbine Design
3. Instrumentation and Controls
4. Waste Heat Recovery and HRSG Design
5. Minimizing Fouling of Heat Exchange Surfaces

$CO_2$ capture and storage is capable of achieving 90% reduction of produced $CO_2$ emissions and thus considered to be the most effective control method. Efficient combustion turbine design, instrumentation and controls, waste heat recovery and HRSG design, and minimization of fouling of heat exchange surfaces are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, ranking is not possible.

**Step 4: Evaluation of control technologies in order of most effective to least effective, with consideration of economic, energy, and environmental impacts and document results**

1. Carbon Capture and Sequestration. M&G Resins developed a cost analysis and additional impacts analysis for CCS for the site that provides the basis for eliminating the technology in this step of the BACT process as a viable control option based on economic costs. The analysis included the $CO_2$ streams from all the combustion processes except the flare listed in Tables 1a, 1b, and 1c, above, and not just the Utility Plant sources subject to this specific permit. Their analysis can be seen as Appendix B of the permit application update on March 15, 2014.

   There are a number of other environmental and operational issues related to the installation and operation of CCS that must also be considered in this evaluation. First, operation of CCS capture and compression equipment would require substantial additional electric power. For example, operation of carbon capture equipment at a typical natural gas fired combined cycle plant is estimated to reduce the net energy efficiency of the plant from approximately 50% (based on the fuel higher heating value (HHV)) to approximately 42.7% (based on fuel HHV).[12]

   To provide the amount of reliable electricity needed to power a capture system, M&G asserts that they would need to significantly expand the scope of the utility plant proposed with this project to install one or more additional electric generating units, which are sources of conventional (non-GHG) and GHG air pollutants themselves. To put these additional power requirements in perspective, gas-fired electric generating units typically emit more than

[12] US Department of Energy, National Energy Technology Laboratory, "Costs and Performance Baseline For Fossil Energy Plants, Volume 1 - Bituminous Coal and Natural Gas to Energy", Revision 2, November 2010

100,000 tons $CO_2e$/yr and would themselves, require a PSD permit for GHGs in addition to non-GHG pollutants.

Likewise, M&G would need to construct a 441 mile long pipeline to the SACROC facility in order to transport the $CO_2$ for sequestration to suitable locations for long term storage/sequestration. Pipeline costs were also considered in the economic analysis provided in Appendix B of the permit application update on March 15, 2014. Construction of such a pipeline would require procurement of right-of-ways which can be a lengthy and potentially difficult undertaking. Pipeline construction would also require extensive planning, environmental studies and possible mitigation of environmental impacts from pipeline construction. Therefore, the transportation of GHGs for this project would potentially result in negative impacts and disturbance to the environment in the pipeline right-of-way.

As with the capture and transportation costs, M&G Resins provided a cost analysis for the geological sequestration of $CO_2$ from the site (without any post-processing), which is also provided in Appendix B of the permit application updated dated March 15, 2014.

According to this provided information in that Appendix, the studied CCS control option would use amine stripping of the $CO_2$ from each emissions stream of the heaters and RTOs from the PET Plant and Option 1 of the Utility project for an approximate 90% reduction in $CO_2$ emissions from the site. This method was selected as the best method available, even though all emissions are primarily from the combustion of natural gas, with the maximum emissions stream having less than 10% by volume $CO_2$, and the RTOs having a $CO_2$ content of approximately 2%, both streams relatively low in concentration which would impede the efficient use of amine stripping. The costs included the construction of an estimated 441 mile pipeline for transportation to and long term storage in the SACROC formation.

CCS Total Cost Estimate. The total capital cost of capture, transportation, and geological sequestration (without pretreatment) is projected to be approximately $683 million, which would bring the total project cost to approximately 1.683 billion dollars, with the CCS control resulting in 41% of the total cost of the project. The annual operating and maintenance costs were estimated to be approximately $56 million. Thus, the average annual $CO_2$ control cost, based on a 30-year period and an 8.5% interest rate applied to the capital costs, is estimated to be nearly $96 million. M&G has determined that the average annual cost effectiveness of the studied control would be $116.70/ton. At this price, M&G asserts, the project would not be economically viable. As stated previously, this case was developed to include not only the gas turbine emissions, but all of the combustion sources at the site with the exception of the flare.

It should be noted that M&G's cost estimation indicated above may understate the actual cost, because it does not include additional costs for the following items that would be needed to implement CCS for the Project (includes the PET Plant and the Utility Plant):

- additional gas conditioning and stream cleanup to meet specifications for final transport and sequestration.
- gas gathering system piping to collect vent gas from sources located in different areas of the plant

- costs of additional electric generating units required to power the capture and compression system (including design, procurement, permitting, installation, operating and maintenance costs); and,
- cost of obtaining rights of way for construction of a 441-mile pipeline.

These items would require significantly more effort to estimate.

EPA Region 6 reviewed M&G Resins' CCS cost estimates and additional impacts considerations and believes it adequately approximates the cost of a CCS control for this project. The EPA believes that these costs together with the technical limitations described in the CCS Capture and Sequestration sections above, and in light of the additional environmental air quality impacts incident to the generation of the additional energy required to implement CCS, indicate that CCS is not BACT for this project.

2. Efficient Combustion Turbine Design. The CHP plant will include one General Electric (GE) LM6000 aeroderivative natural gas-fired combustion turbine (CT) exhausting to a heat exchanger for waste heat recovery (i.e. the HRSG). The combustion turbine proposed by M&G Resins is being installed in a combined heat and power (CHP) configuration. Since combustion turbine exhaust energy is being recovered and harnessed for use along with electrical energy from the generator, more of the fuel burned in a CHP application is recovered as useful energy than in a simple-cycle combustion turbine application. Waste heat will be recovered from the combustion turbine using a heat recovery system. The use of the waste gas heat recovery system will allow for production of steam to be used in M&G Resins' PET Plant, reducing the need for another fired steam generator. In addition, the transfer of most of the combustion turbine exhaust energy to HRSG increases the overall cycle efficiency of the combustion turbine in the combined heat and power configuration.

3. Instrumentation and Controls. Modern combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital-type and is supplied with the combustion turbine. The distributed control system (DCS) controls all aspects of the turbine's operation, including the fuel feed and burner operations, to achieve efficient low-NOx combustion. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency low-emission performance for full load and partload conditions.

4. Waste Heat Recovery and HRSG Design. In a simple cycle configuration, the hot combustion gases exiting the combustion turbine are exhausted to the atmosphere as "wasted" heat. In a cogeneration configuration, these same hot gases are routed through a HRSG to produce steam that is then supplied to the neighboring chemical manufacturing plant as usable thermal energy. Additional natural gas is burned in duct burners in the HRSG to generate additional steam.

   Efficient design of the HRSG improves overall thermal efficiency. Efficient design features of the HRSG includes the following: use of finned tubes to extend the heat transfer surface; modular type heat recovery surfaces for efficient, economical heat recovery; use of a heat exchanger to recover heat from the HRSG exhaust gas to preheat incoming HRSG boiler feedwater; use of a heat exchanger to recover heat from the HRSG blowdown to preheat boiler feedwater; use of hot condensate as feedwater which results in less heat required to produce steam in the HRSG, thus improving thermal efficiency; and application of insulation to the HRSG surfaces and steam and water lines to minimize heat loss from radiation.

5. Minimizing Fouling of Heat Exchange Surfaces. HRSGs are made up of a number of tubes within the shell of the unit that are used to generate steam from the combustion turbine exhaust gas waste heat. To maximize this heat transfer, the tubes and their extended surfaces need to be as clean as possible. Fouling of the tube surfaces impedes the transfer of heat. Fouling occurs from the constituents within the exhaust gas stream. To minimize fouling, filtration of the inlet air to the combustion turbine is performed. Additionally, cleaning of the tubes is performed during periodic outages. By reducing the fouling, the efficiency of the unit is maintained.

**Step 5: Selection of BACT**

M&G Resins proposes, and EPA agrees that BACT for this combustion turbine are the following energy efficiency processes, practices, and designs for the proposed combined heat and power combustion turbine:

1. Efficient Combustion Turbine Design.
2. Instrumentation and Controls.
3. Waste Heat Recovery and HRSG Design.
4. Minimizing Fouling of Heat Exchange Surfaces

M&G Resins also proposes and EPA agrees that the CHP Unit meet a numerical efficiency measure in the form of a 12-month rolling average minimum thermal efficiency for the combined heat and power combustion turbine and duct fired heat recovery steam generator of 60%. The CHP Unit thermal efficiency will be calculated as follows:

CHP Unit Efficiency = [(Heat Content of Steam Produced (MMBtu) + (Turbine Gross Electrical Output converted to MMBtu)] / [Turbine and Duct Burner fuel firing rate x Lower Heating Value of fuel (MMBtu)]

Compliance with the permit emissions limitations will be demonstrated by monitoring GCV, carbon content of the fuel, and fuel gas flow and determining $CO_2$ emissions in accordance with 40 CFR Part 98 Subpart C § 98.33(a)(3)(iii). The emission associated with $CH_4$ and $N_2O$ are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2, fuel usage, and the actual heat input (HHV).

To date, other GHG BACT limits for combined heat and power turbines are summarized in the table below:

| Project | Permit Number | Description | BACT |
|---|---|---|---|
| Westlake Vinyls Co., LP in Louisiana | PSD-LA-754 (12/06/2011) | Three cogeneration trains with GE LM6000 PF Sprint, 50 MW Gas Turbines with 70 MMBtu/hr Duct Fired Heat Recovery Steam Generators | Good Combustion Practices |
| BASF Fina Petrochemicals in Texas | PSD-TX-903-GHG (08/24/2012) | 310.4 MMBtu/hr Duct Burners on existing gas turbine | 60% Thermal Efficiency for Cogeneration Unit, 12-month rolling average, calculated as: [(Heat Content of Steam Produced) + (Heat Content of Power Produced)]/(Heat Content of Fuel Supply) |
| Air Liquide Large Industries US in Texas | No draft permit yet | Four GE 7EA (80 MW) Gas Turbines exhausting to existing duct-fired Heat Recovery Steam Generators (no steam turbine generator) | 7,720 Btu(HHV)/kWh gross equivalent based on a 365-day rolling average. |
| Copano Processing LP in Texas | PSD-TX-104949-GHG (draft) | Solar Mars 100 Gas Turbines (15,000 hp) with Heat Recovery Steam Generators | 40% Thermal Efficiency, 12-month rolling average |

The control technology and other requirements selected as BACT requirements in this case are consistent with BACT requirements of other similar sources recently proposed or permitted.

**BACT Analysis for Auxiliary Boilers A1, A2, and B (Option 1 EPN: AUXBLRA1 and AUXBLRA2 or Option 2 EPNs: AUXBLRA1, AUXBLRA2, and AUXBLRB1)**

Auxiliary Boiler A1 and A2 are 445 MMBtu/hr (HHV) heat input and Auxiliary Boiler B is 250 MMBtu/hr (HHV) heat input. In Option 1 and Option 2, the boilers will only be used to provide process steam rather than run a steam turbine to generate electricity. All three boilers will have the potential to operate continuously and all will be fired on pipeline-quality natural gas. Each boiler will be controlled with an SCR system. Given the similarity in relative size and design, the BACT analysis is the same for each boiler.

**Step 1: Identification of Potential Control Technologies for GHGs**

1. Carbon Capture and Sequestration (CCS) – CCS is an available add-on control technology that is applicable for all of the site's affected combustion units.

Comparatively, $CO_2$ emissions contribute the most volume (greater than 99%) to the overall emissions; therefore, additional analysis is not required for $CH_4$ and $N_2O$.

2. Efficient Boiler Design - New boilers can be designed with efficient burners and refractory and insulation materials in the boiler walls, floor, and other surface to minimize heat loss and increase overall thermal efficiency.

3. Automated Boiler Air/Fuel Control - Monitoring of oxygen concentration in the flue gas to be used to control air to fuel ratio on a continuous basis for optimal efficiency

4. Condensate Recovery – Return of hot condensate for use as feedwater to the boilers. Use of hot condensate as feedwater results in less heat required to produce steam in the boilers, thus improving thermal efficiency.

5. Economizer – Use of a heat exchanger to recover heat from the exhaust gas to preheat incoming boiler feedwater.

6. Boiler Blowdown Heat Recovery – Use of a heat exchanger to recover heat from boiler blowdown to preheat feedwater results in an increase in thermal efficiency.

7. Use of Low Carbon Fuels - Natural gas will be used for Auxiliary Boiler fuel.

**Step 2: Elimination of Technically Infeasible Alternatives**

All options identified in Step 1 are considered technically feasible for this project. Refer to the explanation in BACT analysis of the combustion turbine above for a description of CCS which is considered demonstrated in practice and technically feasible for all the proposed combustion devices included in this permitting action (turbine/duct burner and the three auxiliary boilers) as well as relevant combustion sources from the PET plant permit.

**Step 3: Ranking of Remaining Technologies Based on Effectiveness**

1. CCS is the most effective control technology available of the techniques identified in this BACT analysis for the boilers.

2-7. As all of the energy efficiency related processes, practices, and designs discussed in Step 1 are being proposed for the boilers, a ranking of those control technologies is not necessary for this application.

**Step 4: Evaluation of control technologies in order of most effective to least effective, with consideration of economic, energy, and environmental impacts**

1. CCS. This technology was eliminated in Step 4 of the BACT analysis for the gas turbine above. Since the CCS analysis in that Step addressed all combustion sources at the site (excluding the flare) as part of the economic and ancillary costs, CCS was eliminated for the boilers as well as the gas turbine, and for the same reasons as previously identified.

2.-7 All of the energy efficiency related processes, practices, and designs discussed in Step are technically possible and have no adverse economic or environmental impact, and as such remain as BACT candidates in this step.

**Step 5** – Selection of BACT

**Step 5: Selection of BACT**

To date, other GHG BACT limits for boilers and heaters are summarized in the table below:

| Project | Permit Number | Description | BACT |
|---|---|---|---|
| Port Dolphin Energy, LLC Project | DPA-EPA-R4001 (Issued by EPA Region 4 on 12/01/2011) | Four 278 MMBtu/hr Natural Gas Fired Boilers | 117 lb CO2e/MMBtu. Tuning, optimization, instrumentation and controls, and turbulent flow within the fire tubes for GHG control (no thermal efficiency limit) |
| Entergy Louisiana LLC Ninemile Point Electric Generating Plant | PSD-LA-752 (08/16/2011) | 338 MMBtu/hr Natural Gas fired Boiler | 117 lb CO2e /MMBtu. Proper operation and good combustion practices. (no thermal efficiency limit) |
| BASF Final Petrochemicals | PSD-TX-903-GHG (08/24/2012) | 425.4 MMBtu/hr Natural Gas Fired Steam Package Boilers | 77% Thermal Efficiency, 12-month rolling average |
| Iowa Fertilizer Company | 12-A-386-P (10/26/2012) | 472.4 Natural Gas Fired Auxiliary Boiler | 51,748 ton/yr CO2e (no thermal efficiency limit) |
| Chevron Phillips Chemical | PSD-TX-748-GHG (01/17/2013) | 500 MMBtu/hr Very High Pressure Boiler (natural gas fired) | 77% Thermal Efficiency, 12-month rolling average |

M&G Resins proposes as BACT for this project, the following energy efficiency processes, practices, and designs for the proposed auxiliary boilers:

1. Efficient Boiler Design.
2. Automated Boiler Air/Fuel Control.
3. Condensate Recovery.
4. Economizer.
5. Boiler Blowdown Heat Recovery.
6. Use of natural gas, a low carbon fuel.

M&G Resins also proposes to meet a 12-month rolling average minimum thermal efficiency for each auxiliary boiler of 77%. The Auxiliary Boiler thermal efficiency will be calculated as follows.

Auxiliary Boiler Efficiency = [(Heat Content of Steam Produced (MMBtu)] / [Auxiliary Boiler fuel firing rate x Lower Heating Value of fuel (MMBtu)]

Compliance with permit emissions limitations (depending on what option is chosen) will be demonstrated by monitoring GCV, carbon content of the fuel, and fuel gas flow and determining CO2 emissions based on the Tier III methodology in accordance with 40 CFR Part 98 Subpart C §98.33(a)(3)(iii). The emissions associated with $CH_4$ and $N_2O$ are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2, fuel usage, and the actual heat input (HHV).

**BACT Analysis for Natural Gas Fugitives and MSS for Natural Gas Venting (EPN: NG-FUG and MSS-FUG) under both Options 1 and 2**

The proposed project will include natural gas piping components. These components are potential sources of methane and $CO_2$ emissions due to emissions from rotary shaft seals, connection interfaces, valve stems, and similar points. Emissions can occur when a fuel system or pipe run must be de-inventoried in association with any operational reason, including for safety purposes.

**Step 1: Identification of Potential Control Technologies for GHGs**

1. Implementation of leak detection and repair (LDAR) program using a hand held analyzer.

2. Implementation of alternative monitoring using a remote sensing technology such as infrared cameras

3. Implementation of audio/visual/olfactory (AVO) leak detection program.

4. Minimization of pipeline de-inventorying to atmosphere. When equipment must be de-inventoried of GHG containing gasses, in order to safely perform necessary plant operations related to startup, shutdown, maintenance, or repair operations, and it is impossible that the vented emissions be controlled by the ordinary control device, the vented stream volume must be minimize, to the extent practicable and necessary to safely perform the necessary operations of the plant.

**Step 2: Elimination of Technically Infeasible Alternatives**

All options identified in Step 1 are considered technically feasible for this project.

**Step 3: Ranking of Remaining Technologies Based on Effectiveness.**

1. Implementation of leak detection and repair (LDAR) program using a hand held analyzer. The use of a LDAR program with a portable gas analyzer meeting the requirements of 40 CFR 60, Appendix A, Method 21, can be effective for identifying leaking methane. Quarterly instrument monitoring with a leak definition of 10,000 part per million by volume (ppmv) (TCEQ 28M LDAR Program) is generally assigned a control efficiency of 75% for valves, relief valves, sampling connections, and compressors and 30% for flanges. Quarterly instrument monitoring with a leak definition of 500 ppmv (TCEQ 28VHP LDAR Program) is generally assigned a control efficiency of 97% for valves, relief valves, and sampling connections, 85% for compressors, and 30% for flanges

2. Implementation of alternative monitoring using a remote sensing technology such as infrared cameras. The U.S. EPA has allowed the use of an optical gas imaging instrument as an alternative work practice for a Method 21 portable analyzer for monitoring equipment for leaks in 40 CFR 60.18(g).

3. Implementation of audio/visual/olfactory (AVO) leak detection program. For components containing inorganic or odorous compounds, periodic AVO walk-through inspections provide predicted control efficiencies of 97% control for valves, flanges, relief valves, and sampling connections, and 95% for compressors.[13]

4. Minimization of pipeline de-inventorying to atmosphere. There is no firm control efficiency value assigned to this workpractice standard.

**Step 4: Evaluation of control technologies in order of most effective to least effective, with consideration of economic, energy, and environmental impacts**

All of the instrumental and AVO equipment leak techniques are well established control technology, and so remain viable candidates for BACT.

With regard to the necessity of de-inventorying components or fuel systems in GHG service to assure the ongoing proper and safe operation of the source, minimization of the volume of the gasses so de-inventoried to atmosphere is the only practical workpractice standard that can be implemented to minimize the GHG from these events.

**Step 5: Selection of BACT**

Due to the very low volatile organic compound (VOC) content of natural gas, the source will not be subject to any VOC leak detection programs by way of its State/PSD air permit, TCEQ Chapter 115 – Control of Air Pollution from Volatile Organic Compounds, New Source Performance Standards (40 CFR Part 60), National Emission Standard for Hazardous Air Pollutants (40 CFR Part 61); or National Emission Standard for Hazardous Air Pollutants for Source Categories (40 CFR Part 63). Therefore, any leak detection program implemented will be

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[13] Control Efficiencies for TCEQ Leak Detection and Repair Programs available at http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/control_eff.pdf (last accessed July 23, 2014)

solely due to potential greenhouse emissions for the equipment within the Utility Plant. Since the uncontrolled $CO_2e$ emissions from the natural gas piping represent less than 0.01% of the total sitewide $CO_2e$ emissions, any emission control techniques applied to the piping fugitives will provide minimal $CO_2e$ emission reductions.

Based on this top-down analysis, M&G Resins will conduct weekly AVO inspections as BACT for piping components in natural gas. Likewise, the minimization of the volume of gasses de-inventoried or vented to atmosphere from fuel systems or piping and equipment components in GHG service is BACT for such events, where such emissions cannot be routed through their ordinary control device, if any, due to safety concerns.

## IX. Endangered Species Act

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) submitted on March 4, 2014, prepared by the applicant, M&G Resins USA, LLC ("M&G"), and its consultant, Zephyr Environmental Corporation, Inc. ("Zephyr"), thoroughly reviewed and adopted by EPA. M&G is proposing to construct a new plastic resin manufacturing plant at its site located in Corpus Christi, Nueces County, Texas. The facility will consist of a PET Plant (a polyethylene terephthalate (PET) unit and a terephthalic acid (PTA) unit), and a new heat and/or heat and power utility plant (Utility Plant) both owned and operated by M&G. The PET Plant and the Utility Plant will receive a separate Greenhouse Gas Permit (GHG) permit, but for the purpose of Section 7 of the Endangered Species Act, EPA is relying on a Biological Assessment that includes the collective emissions from both projects and their impacts to endangered species. The biological assessment performed for M&G included in its field survey the physical land area where the new facilities will be built.

A draft BA has identified seventeen (17) species listed as federally endangered or threatened in Nueces County, Texas:

| **Federally Listed Species for Nueces 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** |
|---|---|
| **Reptiles** | |
| Green sea turtle | *Chelonia mydas* |
| Hawksbill sea turtle | *Eretmochelys imbriacata* |
| Kemp's ridley sea turtle | *Lepidochelys kempii* |
| Leatherback sea turtle | *Dermochelys coriaea* |

| **Federally Listed Species for Nueces 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** |
|---|---|
| Loggerhead sea turtle | *Caretta caretta* |
| **Birds** | |
| Piping plover | *Charadrius melodus* |
| Northern Aplomado falcon | *Falco femoralis septentrionalis* |
| Whooping crane | *Grus americanus* |
| Red knot | *Calidris canutus rufa* |
| Eskimo curlew | *Numenius borealis* |
| **Fish** | |
| Smalltooth sawfish | *Pristis pectinata* |
| **Mammals** | |
| Gulf coast jagaurundi | *Herpailuraus yagouaroundi cacomitli* |
| Ocelot | *Leopardus pardalis* |
| West Indian manatee | *Trichechus manatus* |
| Red wolf | *Canis rufus* |
| **Plants** | |
| Slender rush-pea | *Hoggmannseggia tenella* |
| South Texas ambrosia | *Ambrosia cheiranthifolia* |

EPA has determined that issuance of the proposed permits to M&G for the new PET plant and Utility Plant will have no effect on ten (10) of these listed species, specifically the red wolf (*Canis rufus*), ocelot (*Leopardus pardalis*), Gulf coast jagaurundi (*Herpailuraus yagouaroundi cacomitli*), slender rush-pea (*Hoffmannseggia tenella*), piping plover (*Charadrius melodus*), Northern Aplomado falcon (*Falco femoralis septentrionalis*), red knot (*Calidris canutus rufa*), eskimo curlew (*Numenius borealis*), South Texas ambrosia (*Ambrosia cheiranthifolia*), and smalltooth sawfish (*Pristis pectinata*). These species are either thought to be extirpated from the county or Texas or not present in the action area.

Two terrestrial (2) species, whooping crane (*Grus americana*) and West Indian manatee (*Trichechus manatus*), identified are species that may be present in the Action Area. As a result of this potential occurrence and based on the information provided in the draft BA, the issuance of the permit may affect, but is not likely to adversely affect the whooping crane and the West Indian manatee.

EPA has determined that these federally-listed endangered marine species can potentially found within the action area of the project.

- leatherback sea turtle (*Dermochelys coriacea*)
- green sea turtle (*Chelonia mydas*)

- Kemp's ridley sea turtle (*Lepidochelys kempii*)
- loggerhead sea turtle (*Caretta caretta*)
- Hawksbill sea turtle (*Eretmochelys imbricate*)

As a result of this potential occurrence and based on the information provided in the draft BA, the issuance of the permit may affect but is not likely to adversely affect the leatherback sea turtle, green sea turtle, Kemp's ridley sea turtle, loggerhead sea turtle, and hawksbill sea turtle.

On April 4 2014, EPA submitted the final draft BA, dated March 5, 2014, to the Southwest Region, Corpus Christi, Texas Ecological Services Field Office of the USFWS for its concurrence that issuance of the permit may affect, but is not likely to adversely affect the whooping crane, West Indian manatee, leatherback sea turtle, green sea turtle, Kemp's ridley sea turtle, loggerhead sea turtle, and hawksbill sea turtle. USFWS provided concurrence and agreed with EPA's determinations on April 23, 2014.

EPA submitted the final draft BA, dated March 5, 2014, to the NOAA Southeast Regional Office, Protected Resources Division of NMFS on March 31, 2014, for its concurrence that issuance of the permit may affect, but is not likely to adversely affect the leatherback sea turtle, green sea turtle, Kemp's ridley sea turtle, loggerhead sea turtle, and hawksbill sea turtle. NOAA provided concurrence and agreed with EPA's determinations on June 3, 2014.

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.

## X. 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 the National Oceanic Atmospheric Administration's National Marine Fisheries Service (NMFS), regional fishery management councils, 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 Zephyr on behalf of M&G, submitted on July 9, 2013, and reviewed and adopted by EPA. The EFH assessment looks at the total emissions and impacts from both GHG projects on marine and fish habitats.

The facility affects tidally influenced portions of the Nueces River, which adjoins to Nueces Bay and feeds into Corpus Christi Bay leading to the Gulf of Mexico, and Viola Ship Channel, which adjoins to the Corpus Christi Bay leading to the Gulf of Mexico. These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult stages of red drum (*Sciaenops ocellatus*), shrimp (4 species), and reef fish (43 species) and the stone crab (*Menippe mercenaria)*. The EFH information was obtained from the NMFS's website (http://www.habitat.noaa.gov/protection/efh/efhmapper/index.html).

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permits allowing for the construction of the M&G PET Plant and Utility Plant will have no adverse impacts on listed marine and fish habitats. The assessment's analysis, which is consistent with the analysis used in the BA discussed above, shows the projects' construction and operation will have no adverse effect on EFH.

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 essential fish habitat report can be found at EPA's Region 6 Air Permits website at: http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

## XII. National Historic Preservation Act

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 and adopted a cultural resource report prepared by Horizon Environmental Services, Inc. (Horizon) on behalf of Zephyr, for M&G facilities, submitted in March 10, 2014.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be location of the M&G PET facility and Utility Plant. Horizon conducted a field survey, including shovel testing and backhoe trenching, of the APE and a desktop review within a 1.0-mile radius of the APE. The desktop review included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). Based on the desktop review, eight archaeological sites potentially eligible for listing on the National Register were identified within 1.0-mile of the APE; however all eight sites were located outside the APE.

EPA Region 6 determines that since there are no historic properties or archaeological resources located within the APE, issuance of the permits to M&G will not affect properties potentially eligible for listing on the National Register.

On March 6, 2014, 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. On August 13, 2014. EPA provided a copy of the report to Texas's State Historic Preservation Officer (SHPO) for consultation and concurrence with its determination. SHPO provided concurrence and agreed with EPA's determinations on August 21, 2014.

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.

## XIII. 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 GHG. 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.

## XVIII. Conclusion and Proposed Action

Based on the information supplied by M&G Resins, our review of the analyses contained in the TCEQ PSD 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 M&G Resins a PSD permit for GHGs for the Utility Plant, 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 emissions, in tons per year (TPY) on a 12-month rolling total, shall not exceed the following:

**Permit Emissions Limitation Table 1A. Annual Emission Limits (Option 1)[1]**

| FIN | EPN | Description | GHG Mass Basis | | TPY $CO_2e$[2,3] | BACT Requirements |
|---|---|---|---|---|---|---|
| | | | | TPY[2] | | |
| CTG | CTG | General Electric LM6000 CT with 263 MMBtu/hr Duct Burner and HRSG | $CO_2$ | 363,652 | 364,027 | Minimum Thermal Efficiency of 60% (LHV basis). See Special Condition III.C.1. and 2. |
| | | | $CH_4$ | 6.86 | | |
| | | | $N_2O$ | 0.69 | | |
| AUXBLRA1 | AUXBLRA1 | Auxiliary Boiler A1 | $CO_2$ | 247,281 | 247,537 | Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2. |
| | | | $CH_4$ | 4.66 | | |
| | | | $N_2O$ | 0.47 | | |
| AUXBLRB | AUXBLRB | Auxiliary Boiler B | $CO_2$ | 127,992 | 128,125 | Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2. |
| | | | $CH_4$ | 2.41 | | |
| | | | $N_2O$ | 0.24 | | |
| NG-FUG | NG-FUG | Natural Gas Fugitives | $CH_4$ | No Emission Limit Established[4] | No Emission Limit Established[4] | Implementation of AVO monitoring program. See Special Condition III.F.1. and 2. |
| MSS-FUG | MSS-FUG | MSS Natural Gas Venting | $CH_4$ | No Emission Limit Established[4] | No Emission Limit Established[4] | Implementation of AVO monitoring program. See Special Condition III.G.1. and 2. |
| **Totals[5]** | | | **$CO_2$** | **738,926** | **$CO_2e$ 740,199** | |
| | | | **$CH_4$** | **34** | | |
| | | | **$N_2O$** | **1** | | |

1. Compliance with the annual emission limits (tons per year) is based on a 12-month, rolling total.
2. 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.
3. Global Warming Potentials (GWP): $CH_4$ = 25, $N_2O$ = 298, $SF_6$=22,800
4. Fugitive process emissions from EPNs NG-FUG and MSS-FUG are estimated to be 20 TPY of $CH_4$, and 511 $CO_{2e}$. The emission limit will be a design/work practice standard as specified in the permit.
5. The total emissions for $CH_4$ and $CO_{2e}$ include the PTE for process fugitive emissions of $CH_4$. Total emissions are for information only and do not constitute an emission limit.

## Permit Emissions Limitation Table 1B. Annual Emission Limits (Option 2)[1]

| FIN | EPN | Description | GHG Mass Basis | | TPY $CO_{2}e$[2,3] | BACT Requirements |
|---|---|---|---|---|---|---|
| | | | | TPY[2] | | |
| AUXBLRA1 | AUXBLRA1 | Auxiliary Boiler A1 | $CO_2$ | 247,281 | 247,537 | Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2. |
| | | | $CH_4$ | 4.66 | | |
| | | | $N_2O$ | 0.47 | | |
| AUXBLRA2 | AUXBLRA2 | Auxiliary Boiler A2 | $CO_2$ | 247,281 | 247,537 | Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2. |
| | | | $CH_4$ | 4.66 | | |
| | | | $N_2O$ | 0.47 | | |
| AUXBLRB | AUXBLRB | Auxiliary Boiler B | $CO_2$ | 127,992 | 128,125 | Minimum Thermal Efficiency of 77% (LHV basis). See Special Condition III.E.1. and 2. |
| | | | $CH_4$ | 2.41 | | |
| | | | $N_2O$ | 0.24 | | |
| NG-FUG | NG-FUG | Natural Gas Fugitives | $CH_4$ | No Emission Limit Established[4] | No Emission Limit Established[4] | Implementation of AVO monitoring program. See Special Condition III.F.1. and 2. |
| MSS-FUG | MSS-FUG | MSS Natural Gas Venting | $CH_4$ | No Emission Limit Established[4] | No Emission Limit Established[4] | Implementation of AVO monitoring program. See Special Condition III.G.1. and 2. |
| **Totals[5]** | | | **$CO_2$** | **622,555** | **$CO_{2}e$ 623,708** | |
| | | | **$CH_4$** | **32** | | |
| | | | **$N_2O$** | **1** | | |

1. Compliance with the annual emission limits (tons per year) is based on a 12-month, rolling total.
2. 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.
3. Global Warming Potentials (GWP): $CH_4$ = 25, $N_2O$ = 298, $SF_6$=22,800
4. Fugitive process emissions from EPNs NG-FUG and MSS-FUG are estimated to be 20 TPY of $CH_4$, and 511 $CO_{2e}$. The emission limit will be a design/work practice standard as specified in the permit.
5. The total emissions for $CH_4$ and $CO_{2e}$ include the PTE for process fugitive emissions of $CH_4$. Total emissions are for information only and do not constitute an emission limit.