UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
BEFORE THE ADMINISTRATOR

IN THE MATTER OF	*	PETITION FOR OBJECTION
Clean Air Act Title V Permit No. 2240-00452-V0	*	
for IGP Methanol, LLC	*	Permit No. 2240-00452-V0
Issued by the Louisiana Department of Environmental Quality	*	

PETITION REQUESTING THAT THE ADMINISTRATOR OBJECT TO THE ISSUANCE OF THE PROPOSED TITLE V AIR PERMIT NO. 2240-00452-V0 ISSUED BY LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY TO IGP METHANOL, LLC FOR THE GULF COAST METHANOL COMPLEX IN PLAQUEMINES PARISH, LOUISIANA

Pursuant to Clean Air Act § 505(b)(2), 42 U.S.C. § 7661d(b)(2), and 40 C.F.R. § 70.8(d), the Sierra Club petitions the Administrator of the United States Environmental Protection Agency ("EPA") to object to the proposed Title V air operating permit no. 2240-00452-V0 ("proposed Title V Permit") issued by the Louisiana Department of Environmental Quality ("LDEQ") to IGP Methanol, LLC ("IGP") authorizing operation of the Gulf Coast Methanol Complex ("Plant") near Myrtle Grove and Ironton in Plaquemines Parish, Louisiana.

Sierra Club respectfully requests that the Administrator object to the proposed Title V Permit because, as demonstrated below, it does not comply with the requirements of the Clean Air Act. The Clean Air Act mandates that the Administrator "shall issue an objection ... if the petitioner demonstrates to the Administrator that the permit is not in compliance with the requirements of the ... [Clean Air Act]." 42 U.S.C. § 7661d(b)(2); *see also* 40 C.F.R. § 70.8(c)(1). The Administrator must grant or deny a petition to object within 60 days of its filing. 42 U.S.C. § 7661d(b)(2).

I. PETITIONER

The Sierra Club is a national nonprofit organization with 67 chapters and over 635,000 members dedicated to exploring, enjoying, and protecting the wild places of earth; practicing and promoting the responsible use of earth's ecosystems and resources; educating and enlisting humanity to protect and restore the quality of the natural and human environment; and using all lawful means to carry out these objectives. One way Sierra Club carries out these objectives is to comment on and challenge air permits that do not conform to the law. The Delta Chapter of the Sierra Club has members who live, work, and recreate in areas that would be affected by air pollution from the Plant if built and operated.

II. LEGAL FRAMEWORK & REQUIREMENTS

The Clean Air Act requires any person wishing to construct a new major stationary source of air pollutants to apply for and obtain a Title V permit before commencing construction. 42 U.S.C. § 7661b(c); *see also* LAC 33:III.507.C.2. The Clean Air Act requires each state to develop and submit to EPA an operating permit program intended to meet the requirements of Title V of the Act. 42 U.S C. § 7661a(d)(l). Louisiana's approved Title V program is incorporated into the Louisiana Administrative Code at LAC 33:III, Chapter 5.

Title V permits are the primary method for enforcing and assuring compliance with the Clean Air Act's pollution control requirements for major sources of air pollution. *Operating Permit Program,* 57 Fed. Reg. 32,250, 32,258 (July 21, 1992). Each Title V permit must list all applicable federally-enforceable requirements and contain enough information to determine how applicable requirements apply to units at the permitted source. The Clean Air Act makes clear that Title V permits must "include enforceable emission limitations and standards . . . and such other conditions as are necessary to assure compliance with *applicable requirements* of [the Clean Air Act and applicable State Implementation Plan ("SIP")]." 42 U.S.C. § 7661c(a) (emphasis added); *see also Sierra Club v. EPA*, 536 F.3d 673 (D.C. Cir. 2008). The Title V operating permit program does not generally impose new substantive air quality control requirements, but does require permits to contain monitoring, recordkeeping, reporting, and other requirements to assure compliance by sources with existing applicable emission control requirements. 57 Fed. Reg. 32250, 32251 (July 21, 1992) (EPA final action promulgating the Part 70 rule). The part 70 regulations contain monitoring rules designed to satisfy this statutory requirement.

As a general matter, permitting authorities must take three steps to satisfy the monitoring requirements in the EPA's part 70 regulations. First, a permitting authority must ensure that monitoring requirements contained in applicable requirements are properly incorporated into the title V permit. 40 CFR 70.6(a)(3) (i)(A). Second, if the applicable requirements contain no periodic monitoring, permitting authorities must add monitoring "sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." 40 CFR 70.6(a)(3)(i)(B). Third, if the applicable requirement has associated periodic monitoring but the monitoring is not sufficient to assure compliance with permit terms and conditions, a permitting authority must supplement monitoring to assure compliance. *See* 40 CFR 70.6(c)(1).

The regulations make clear that the term "applicable requirement" is very broad and includes, among other things, "[a]ny term or condition of any preconstruction permit" or "[a]ny standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under title I of the [Clean Air] Act." 40 C.F.R. § 70.2; *see also* LAC 33:III.507.A.3 ("Any permit issued under the requirements of this Section shall incorporate all federally applicable requirements for each emissions unit at the source."). Indeed, "applicable requirements" includes the duty to obtain a construction permit that meets the requirements of the Act's Prevention of Significant Deterioration ("PSD") program. *See* 42 U.S.C. § 7475. Thus, Title V permits must incorporate the terms and conditions of the PSD permit because they are applicable requirements.

Clean Air Act regulations command that "each applicable State Implementation Plan . . . shall contain emission limitations and such other measures as may be necessary to prevent significant deterioration of air quality." 40 C.F.R. § 51.166. Louisiana SIP provisions that incorporate the Clean Air Act's PSD requirements are in LAC 33:III.509. 40 C.F.R. § 52.970(c) (identifying EPA approved regulations in the Louisiana SIP); *see also* 40 C.F.R. § 52.999(c) and 52.986.

The Louisiana PSD regulations apply to the construction of a "major stationary source," which include certain listed sources, such as a chemical processing plant like the Gulf Coast Methanol Complex, that "ha[ve] the potential to emit[] 100 tons per year or more" of any PSD regulated pollutant (except greenhouse gases). LAC 33:III.509.B. PSD regulated pollutants include, among others, nitrogen oxides ("NOx"), sulfur dioxide ("SO_2"), particulate matter ("PM"), volatile organic compounds ("VOC"), carbon monoxide ("CO"), and greenhouse gases. *Id.* Major stationary sources as defined under LAC 33:III.509.B must meet the state's PSD requirements under LAC 33:III.509.J-R. LAC 33:III.509.A.2. "No new major stationary source or major modification to which the requirements of Subsection J-Paragraph R.5 of this Section apply shall begin actual construction without a permit that states that the major stationary source or major modification will meet those requirements." LAC 33:III.509.A.3. Such requirements include, among other things, the following:

(1) Application of "best available control technology ["BACT"] for each regulated NSR pollutant [i.e., PSD pollutant] that [the source] would have the potential to emit in significant amounts;" LAC 33:III.509.J.2.

(2) Demonstration by the "owner or operator of the proposed source . . . that allowable emission increases from the proposed source [], in conjunction with all other applicable emissions increases or reductions, including secondary emissions, would not cause or contribute to air pollution in violation of: a. any national ambient air quality standard in any air quality control region; or b. any applicable maximum allowable increase over the baseline concentration in any area." LAC 33:III.509.K.1.

(3) A "preliminary determination [by LDEQ] whether construction should be approved, approved with conditions, or disapproved." LAC 33:III.509.Q.1.

(4) Public availability "of all materials the applicant submitted, a copy of the preliminary determination, and a copy or summary of other materials, if any, considered in making the preliminary determination," along with public notice, public comment, and an opportunity for a public hearing. LAC 33:III.509.Q.2.b-c.

See also 40 U.S.C. § 7475(a)(2)-(8).

In reviewing a Title V petition, the Administrator must object where petitioners "demonstrate" that the permit "is not in compliance with the requirements of [the Clean Air Act], including the requirements of the applicable implementation plan." *See* 42 U.S.C. § 7661d(b)(2); *see also* 40 C.F.R. § 70.8(c)(1).

In the PSD context, EPA will "generally look to see whether the Petitioner has shown that the state did not comply with its SIP-approved regulations governing PSD permitting or whether the state's exercise of discretion under such regulations was unreasonable or arbitrary."[1] This inquiry includes whether the permitting authority "(1) follow[ed] the required procedures in the SIP; (2) [made] PSD determinations on reasonable grounds properly supported on the record; and (3) describe[d] the determinations in enforceable terms." *In re Consolidated Environmental Management, Inc.—Nucor Steel Louisiana*, Order on Petition Numbers VI-2010-05, VI-2011-06 and VI-2012-07 (January 30, 2014) (Nucor III Order) at 5 (*citing In the Matter of Wisconsin Power and Light, Columbia Generating Station*, Order on Petition No. V-2008-01 (October 8, 2009) at 8). *See also* A*laska Dep't of Envtl Conservation v. EPA*, 540 U.S. 461 (2004) (upholding U.S. EPA's authority to block a PSD permit where the state permitting authority's BACT determination was unreasonable).

III. PROCEDURAL BACKGROUND

On February 3, 2017, IGP submitted an application for a Title V/ Part 70 air operating permit and a Prevention of Significant Deterioration (PSD) permit to construct and operate the Gulf Coast Methanol Complex near Myrtle Grove and Ironton in Plaquemines Parish, Louisiana to produce methanol to export by marine vessels, reportedly large Panamax vessels.[2] This would be the largest methanol plant in the world. The Plant, as proposed, consists of four identical 5,000 metric ton per day methanol production units located on a 100-acre parcel within the Kinder Morgan Inc., International Marine Terminal. The Plant, as proposed, will produce methanol from natural gas, water, and oxygen feedstocks using the autothermal reforming process. The pure methanol will be sent to tanks and transferred to the Kinder Morgan vessel loading facility for shipment.[3]

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[1] *In re Louisville Gas and Electric Company, Trimble County, Kentucky, Title V/PSD Air Quality Permit # V-02-043 Revisions 2 and 3*, Order Responding to Issues Raised in April 28, 2008 and March 2, 2006 Petitions, and Denying in Part and Granting in Part Requests for Objection to Permit, (August 12, 2009), at 5 (*citing In re East Kentucky Power Cooperative, Inc. (Hugh L. Spurlock Generating Station) Petition No. IB-2006-4*, Order on Petition (August 30, 2007); *In re Pacific Coast Building Products, Inc.*, Order on Petition (December 10, 1999*); In re Roosevelt Regional Landfill Regional Disposal Company*, Order on Petition (May 4, 1999)).

[2]IGP submitted additional information in support of its application dated May 11, 2017, June 8, 2017, and July 21, 2017. *Id.*

[3] CK Associates, Title V/PSD Initial Air Permit Application, Gulf Coast Methanol Complex, Plaquemines Parish, Louisiana, IGP Methanol, LLC, February 2017 ("2/17 Application"). The 2/17 Application was made available for public comment as part of a large compilation of documents totaling 692 pages via a link on the public notice to LDEQ's Electronic Document Management System ("EDMS") as Document 10742163 ("Public Notice Document"). The Public Notice Document also includes supplemental application materials, IGP's modeling protocol, proposed Title V permit with Statement of Basis, proposed PSD permit and related documents. Sierra Club cites to the Public Notice Document by pdf page number.

The Plant, as proposed, is a major source of criteria pollutants and was reviewed under LDEQ PSD regulations at LAC 33:III.509.B. The facility is also a major source of Toxic Air Pollutants (TAPs) pursuant to LAC 33:III, Chapter 51.[4]

LDEQ issued proposed PSD permit No. PSD-LA-820 and proposed Title V permit no. 2240-00452-V0 for public comment on August 15, 2017. The public comment period for the proposed permits was extended and ended on October 10, 2017. Sierra Club filed timely public comments with LDEQ regarding the proposed permits on September 25, 2017 and October 10, 2017.

Under section 505(a) of the Act, 42 U.S.C. § 7661d(a), and 40 C.F.R. § 70.8(a), the relevant implementing regulation, states are required to submit each proposed Title V operating permit to EPA for review. LDEQ submitted the proposed Title V Permit to EPA Region 6 on August 16, 2017. EPA had 45 days from receipt of the proposed permit to object to final issuance of the permit if it determines the permit is not in compliance with applicable requirements of the Act. EPA did not object to the proposed Title V Permit within its 45-day review period, which ended on September 29, 2017.

Section 505(b)(2) of the Act, 42 U.S.C. § 7661d(b)(2), provides that, if EPA does not object to a permit, any person may petition the Administrator—within 60 days of the expiration of EPA's 45-day review period—to object to the permit. *See also* 40 C.F.R. § 70.8(d). Sierra Club files this Petition within 60 days after the expiration of the Administrator's 45-day review period.

Furthermore, the petition must "be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting agency (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period)." 42 U.S.C. § 7661d(b)(2). Sierra Club bases this petition on the comments prepared by Phyllis Fox, Ph.D., PE and submitted on its behalf during the public comment period. *See* Ex. A, Sierra Club Comments, Oct. 10, 2017 at pdf pp. 24-62 "Fox Comments." Sierra Club, thus, meets the procedural requirements for this Title V petition.

According to LDEQ's Electronic Document Management System ("EDMS"), which provides online public access to facility files, LDEQ has not issued a final Title V permit, nor has it responded to public comments on the proposed permit. Furthermore, IGP has not yet commenced construction of the Plant.

IV. GROUNDS FOR OBJECTIONS.

A. <u>The Proposed Title V Permit fails to assure compliance with applicable requirements of IGP's PSD permit</u>.

The proposed Title V permit is deficient because it fails to specify monitoring and testing requirements that assure compliance with the performance standards, BACT emission limits, and

[4] *See* Statement of Basis at 3.

operating requirements established by IGP's proposed PSD permit No. PSD-LA-820. Such performance standards, emission limits, and operating requirements are all applicable requirements of the Clean Air Act. The proposed Title V Permit fails to assure that the proposed BACT limits are met on a continual basis at all levels of operation. Indeed, the proposed Title V Permit fails to require adequate monitoring—or any monitoring at all—for the vast majority of the emission units and pollutants.

The Plant includes 32 separate emission sources as follows:[5]

[5] Public Notice Document, pdf 9-10.

IL-BLR - In-Line Boiler	
PH - Process Heater H-201	
SH - Steam Heater H-202	
FL - Flare	
EG - Emergency Generator	
IDCU - Induced Draft Cooling Unit	
TK-MEOH-01 - Methanol Product Buffer Tank No. 1 (T452-1)	
TK-MEOH-02 - Methanol Product Buffer Tank No. 2 (T452-2)	
TK-SCRUB1 - Tank Scrubber	
TK-NH3-01 - Ammonia Storage Tank No. 1	
TK-NH3-02 - Ammonia Storage Tank No. 2	
HEATERS – Heater H-201 and H-202 Common Stack	
HSUSD – Heater H-201 and H-202 Startup/Shutdown	
SYN - Methanol Synthesis/Reactor	
DIST - Methanol Distillation	
H2REC - Hydrogen Recovery	
SCV - Methanol Surge Control Vessel T-451	
WW - Wastewater Fugitives (Incl. Maintenance Wastewater)	
FUG - Fugitive Emissions	

AUX-BL - Auxiliary Boiler
WW-EG - WWTS Emergency Generator
TK-MEOH-01 - Methanol Storage Tank No. 1
TK-MEOH-02 - Methanol Storage Tank No. 2
TK-MEOH-03 - Methanol Storage Tank No. 3
TK-MEOH-04 - Methanol Storage Tank No. 4
TK-MEOH-05 - Methanol Storage Tank No. S
TK-MEOH-06 - Methanol Storage Tank No. 6
MEOH-TK-SCRUB - Methanol Storage Tank Scrubber
MEOH-MVL - Marine Vessel Loading
MEOH-MVL-SCRUB - Marine Vessel Loading Scrubber
WWTS - Wastewater Treatment System
EB – Equalization Tank (WWTS)
AI204812 – Gulf Coast Methanol Complex

Emission limits and rates for these units are listed in the proposed Title V Permit under "Emission Rates for Criteria Pollutants and CO_2e." However, the proposed Title V Permit conditions (referred to as Specific Requirements in the permit) fail to include any monitoring for the vast majority of these emission rates; and for those that are included, the monitoring is inadequate to demonstrate compliance with BACT limits and facility design.

The proposed Title V Permit includes BACT requirements and other emission limits for some pollutants as direct emissions or surrogates, but fails to require any compliance monitoring at all for the following sources:

- In-Line Boilers: PM10/PM2.5, CO, VOC[6]
- Flares: Opacity[7]
- Engines: PM10/PM2.5, VOC, CO, NOx[8]
- Induced Draft Cooling Units: VOC, Opacity, Drift Rate[9]

In addition, the proposed Title V Permit fails to establish any emission limits to assure that emissions remain below the BACT threshold for SO_2, which did not trigger BACT.

Furthermore, the proposed Title V Permit also does not require any monitoring for the following:

- Flares[10]
- Storage Tanks: HAPs, VOCs[11]
- Scrubbers: VOCs[12]
- Heaters: total suspended particulate[13]
- Reactors: TOC[14]
- Marine Vessel Loading: VOC, % reduction[15]

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[6] Condition 42.

[7] Condition 117.

[8] Condition 123.

[9] Conditions 139-144.

[10] Flares: Conditions 66-122.

[11] Tanks: Conditions 145-158.

[12] Scrubbers: Conditions 163-173.

[13] Condition 175.

[14] Condition 184.

[15] Conditions 335-336. Condition 341 requires submittal of test results, but there is no condition requiring testing.

- Marine Vessel Loading Scrubber: VOC, % reduction[16]
- Methanol Complex: GHGe[17]

The proposed Title V Permit also fails to establish adequate monitoring for:

- Scrubbers: HAPs (monitored once)[18]
- Heaters: stack test every five years for PM10/PM2.5, NOx, CO, VOC[19]

The Heaters Common Stack Common Requirements under Condition 176, which requires a performance/emissions test on startup and every five years thereafter, is inadequate to assure compliance with applicable PSD requirements and is not justified in the record. First, the pollutants that would be measured are ambiguous. The subsequent condition, 177, suggests stack tests would only be conducted for NOx and CO while the prior condition, 175, sets forth a limit on total suspended particulate matter (TSP), implying that Condition 176 may apply to total suspended particulate matter, as no monitoring for TSP is included elsewhere in the proposed Title V Permit. Condition 176 must be modified to identify the pollutant(s) that will be monitored in the stack test. Second, if compliance with the NOx and CO BACT limits is intended, a stack test every five years is not adequate. Continuous Emission Monitoring Systems ("CEMS") are available for both NOx and CO and are routinely used to determine compliance with NOx and CO limits on heaters.

A stack test every five years, regardless of the pollutant(s), is not adequate to determine compliance with a BACT or any other emission limit. A stack test typically lasts three hours and is conducted under ideal operating conditions, generally after the source is tuned up, which minimizes emissions compared to routine operation. Further, fired sources in methanol plants do not operate at a uniform rate, but rather vary depending on the status of the catalyst used in the methanol synthesis process. A three-hour optimal snapshot every five years is not adequate to assure the emissions of any pollutant meet the BACT emission rates or that emissions of SO_2 and lead (Pb) remain below the BACT significance thresholds.

In order to assure that emissions meet the BACT emission limits continuously, as required, they must be measured continuously from each source. Fired sources in methanol plants do not operate at a steady rate. Steady-state operation allows short-term sampling, such as periodic stack tests, to determine annual emissions by multiplying pounds per unit of fuel combusted as measured in a periodic stack test by total fuel use (or firing rate). However, for a non-steady-state source, a 3-hour sample collected once every five years cannot yield a

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[16] Conditions 370-371. Condition 376 requires submittal of test results, but there is no condition requiring testing.

[17] Condition 414 (0.38 ton/ton MeOH).

[18] Scrubbers: Condition 170.

[19] Condition 65.

representative estimate of annual emissions from a boiler or any other source that does not operate at steady state.

In rejecting an air permit for the Yuhuang methanol plant in Louisiana, the EPA concluded that a 5-year stack testing frequency for the auxiliary boiler is inadequate to ensure compliance with the auxiliary boiler CO emission limit, and the permit record lacked any justification for the frequency of this stack testing condition.[20] The EPA also found that "a single stack test, repeated every five years" was not sufficient for purposes of demonstrating compliance with the permit's VOC limits.[21] The record in this case similarly lacks any justification for 5-year stack testing.

For the boilers, the proposed Title V Permit provides specific emission limits for NOx and requires compliance using continuous emission monitoring systems (CMS) for the boilers.[22] However, the proposed Title V Permit fails to require any testing at all for NOx emissions from other emission units.[23] It also establishes emission limits for PM10/PM2.5, CO, and VOC, but does not require any testing to determine if these limits are met.[24] No emission limits or testing are established for other emission units and pollutants, including the auxiliary boiler[25] and emissions of all pollutants except NOx from the heaters.[26]

The failure to specify any emission limits or monitoring for the tanks is particularly egregious, as studies have demonstrated that the methods used to estimate tank emissions significantly underestimate VOC emissions. *See* C.1 below.

B. <u>Information necessary for meaningful public input on the air quality analysis was not made available for public review and comment</u>.

One of the stated purposes of PSD is to "assure that any decision to permit increased air pollution in any area to which [PSD] applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decision making process." 42 U.S.C. § 7470(5). PSD and the SIP require the air quality impact analysis for a new major source to be available for public review and comment at a public hearing. 42 U.S.C. § 7475(a); LAC 33:III.509.Q.2. LDEQ must also make available

[20] *Yuhaung Chemical Inc.*, EPA Order on Petition No. Vl-2015-03, p.14 (2016) (Yuhuang Order), p.18.

[21] *Id.* at 21.

[22] Boilers, Conditions 1-9.

[23] Heaters, Conditions 44-65.

[24] In-Line Boilers, Condition 42; Cooling Tower Drift, Condition 144; Cooling Tower Opacity, Condition 142; Heaters, Condition 65.

[25] Condition 43.

[26] Heaters, Conditions 44-65.

for public review and comment a copy of all materials submitted by the applicant and a copy or summary of any other materials LDEQ considered in making the preliminary determination. LAC 33:IH.509.Q.2.

The air quality analysis[27] information included in publicly disclosed files is a summary of an air quality analysis, not the analysis itself. That is, the AERMOD modeling files are required to evaluate the analysis, but these files are missing from the information provided for public review. The missing files are cited as being present in Appendix C to the air quality analysis but were not provided for public review. Because these files are missing, the air quality analysis does not contain sufficient information to allow the public to evaluate whether the analysis is accurate and was performed correctly and, therefore, the public was deprived of a full opportunity to review and comment on the air quality analysis. LDEQ, therefore, failed to comply with its approved PSD procedures in the Louisiana SIP under LAC 33:III.509.Q.2, which is a basis for an EPA objection. *See Nucor III Order* at 5 (EPA's authority to oversee the implementation of the PSD program in states with approved programs, "include[s] the requirement[] that the permitting authority [] follow the required procedures in the SIP.") (*citing In the Matter of Wisconsin Power and Light, Columbia Generating Station*, Order on Petition No. V-2008-01 (October 8, 2009) at 8).

Numerous inputs and assumptions are required to run AERMOD, the model used to estimate the air quality impacts of the Plant. These include background ambient air quality data; meteorological data, including wind velocity, wind direction, ambient temperatures, atmospheric stability and mixing height; source characteristics, including emission rates, stack heights, exit velocities, exit temperatures, and stack diameters; terrain data; surface characteristics; grid spacing; building and stack locations and dimensions; urban/rural dispersion coefficient determination; and the handling of variable wind speeds and calm hours, which are often the controlling meteorological conditions for National Ambient Air Quality Standards based on 1-hour concentrations. The processing of the meteorological data is critically important and cannot be assessed without access to the raw meteorological data files.

The maximum modeled concentration, for example, is added to the background ambient concentration. As there is no air quality monitoring station in Plaquemines Parish, it is critically important to disclose how the background concentrations were calculated, supported by the actual monitoring data used in the calculations. The method used to determine background concentrations and the data used in the background determination must be known to assess the accuracy of the maximum modeled concentration.

For NO_2, for example, the background design value could be the overall highest hourly background concentration, which is the most conservative, or the 98th percentile of the annual distribution of daily maximum 1-hour values averaged across the most recent three years of

[27] CK Associates, Air Quality Analysis in Support of PSD Permit No. PSD-LA-820 and Part 70 Permit No. 2240-00452-V0, IGP Methanol LLC, Plaquemines Parish, Louisiana, May 2017 (5/17 Air Quality Analysis), Public Notice Doc, pdf 609-692.

monitored data.[28] The Air Quality Analysis is silent on how—and even if—background was calculated and added to modeled concentrations.

Meaningful public review requires full transparency by the applicant of its modeling work. Regulators must therefore not accept analyses unless the applicant provides a transparent view of the actual applied dispersion modeling equations, and meaningful public comment requires that those transparent dispersion modeling equations and calculations be contained in the application or the record provided to the public for comment.

In addition, the air quality analysis depends on the magnitude of emissions during Plant operation. The 2/17 Application includes spreadsheets in Appendix A[29] that calculate operational emissions. This appendix contains 30 pages of detailed emission calculation spreadsheets. This information is contained in pdf versions of formerly live Excel spreadsheets, which were used to calculate emissions. The Public Notice Document fails to include the unlocked Excel spreadsheets, thus preventing any meaningful review of the pdf versions without trial and error re-creation, which is not feasible within the very short review period.

An unlocked Excel spreadsheet allows a reviewer to click on any cell and inspect the calculations that were made to yield the result in the cell. Unlocked Excel spreadsheets are required to review emissions calculations. The pdf versions included in the 2/17 Application, Appendix A, on the other hand, do not allow inspection of underlying formulas. Compounding the problem, the pdf spreadsheets are often not annotated with footnotes that divulge sources and equations used to make the calculations in the emission tables. Without the actual electronic spreadsheets used to perform the IGP emission calculations, meaningful opportunity for public comment on the air quality analysis (including PSD increment consumption) is not possible. For this additional reason, the public was deprived of a full opportunity to review and comment on the air quality analysis, resulting in a violation by LDEQ of the PSD procedures in the Louisiana SIP under LAC 33:III.509.Q.2.

C. <u>LDEQ's conclusion that NOx and VOC emissions are not expected to result in significant ozone impacts is not supported by the permit record.</u>

Section 165(a)(3) of the CAA requires the owner or operator of a major emitting facility, as a condition of obtaining a construction permit, to demonstrate that the facility will not "cause, or contribute to, air pollution in excess of any (A) maximum allowable increase or maximum allowable concentration for any pollutant in any area to which this part applies more than one time per year, (B) national ambient air quality standard in any air quality control region, or (C) any other applicable emission standard or standard of performance under this chapter." The Louisiana SIP requirement is as follows:

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[28] Memorandum from Tyler Fox to Regional Air Division Directors: Re: Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO2 National Ambient Air Quality Standard, March 1, 2011, p. 17; available at https://www.epa.gov/sites/production/files/2015-07/documents/appwno2_2.pdf.

[29] Public Notice Document, pdf 481.

> The owner or operator of the proposed source or modification shall demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emission increases or reductions, including secondary emissions, would not cause or contribute to air pollution in violation of: 1. any national ambient air quality standard in any air quality control region; or 2. any applicable maximum allowable increase over the baseline concentration in any area.

LAC 33:III.509.K. In short, air quality impacts are estimated by adding the increase in each pollutant due to the Plant emissions to the background concentration. In addition, the applicant is required to conduct an air quality analysis in accordance with the requirements under LAC 33:III.509.M, and under 509.O-P depending on the circumstances.

Based on the air quality information provided by IGP, LDEQ concluded as part of its preliminary determination regarding Class I Area Impacts that:[30]

> VOC and NOx are precursors to ozone formation; an ozone impact analysis was conducted to demonstrate that VOC and NOx emissions from the proposed complex will not cause a significant increase in ozone levels in the area. With the proposed NOx emissions of 258.87 tons/year and VOC emissions of 248.51 tons/year, the combined effects of the complex on area ozone level will be 95% of the Modeled Emission Rates for Precursors (MERPs). Therefore, impacts of NOx and VOC emissions from the proposed complex on ozone would be expected to be below the critical air quality threshold.

However, as demonstrated below, this conclusion is incorrect because IGP significantly underestimated the Plant's VOC emissions from its tanks and completely omitted VOC and NOx emissions from construction and marine vessels. For this reason, LDEQ failed to comply with its approved PSD procedures in the Louisiana SIP governing source impacts and air quality analyses, which is a basis for an EPA objection. *See Nucor III Order* at 5 (EPA's authority to oversee the implementation of the PSD program in states with approved programs, "include[s] the requirement[] that the permitting authority [] follow the required procedures in the SIP.") (*citing In the Matter of Wisconsin Power and Light, Columbia Generating Station*, Order on Petition No. V-2008-01 (October 8, 2009) at 8).

1. IGP significantly underestimated the Plant's VOC emissions.

The emission calculations in the 2/17 Application indicate that the tanks emit 75.38 ton/yr of VOCs,[31] or 30% of the total VOC. This is a significant underestimate, based on real-time monitoring of tanks. Many studies have demonstrated that the method used in the 2/17

[30] Public Notice Document, pdf 80.

[31] Public Notice Document, pdf 482-483: (4 x 17.36 + 5.18 + 0.76 = 75.38).

Application to estimate tank emissions, the TANKS 4.09d model based on AP-42 algorithms,[32] significantly underestimates them.

Actual measurements of tank emissions using differential absorption lidar (DIAL)[33] compared to those calculated using AP-42 algorithms indicate that AP-42 substantially underestimates VOC and HAP emissions.[34] This study demonstrates an underestimate of VOC emissions by the AP-42 algorithms used in the TANKS program by a factor of 33.[35] Another similar study demonstrated underestimates by factors of 5 to 15, as summarized in Table 1.[36]

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[32] U.S. EPA, *Compilation of Air Pollutant Emission Factors* ("AP-42"), Chapter 7; available at: https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emission-factors#5thed.

[33] LIDAR is a surveying technology that measures distance by illuminating a target with a laser light. Differential absorption lidar (DIAL) measurements utilize two or more closely spaced (<1 nm) wavelengths to factor out surface reflectivity as well as other transmission losses, since these factors are relatively insensitive to wavelength. When tuned to the appropriate absorption lines of a particular gas, DIAL measurements can be used to determine the concentration (mixing ratio) of that particular gas in the atmosphere. *See* Wikipedia, Lidar; available at https://en.wikipedia.org/wiki/Lidar#Meteorology_and_atmospheric_environment.

[34] Allan K. Chambers, Melvin Strosher, Tony Wootton, Jan Moncrieff, and Philip McCready, Direct Measurement of Fugitive Emissions of Hydrocarbons from a Refinery, *Journal of the Air and Waste Management Association*, v. 58, August 2008, pp. 1047–1056. Abstract available at https://www.ncbi.nlm.nih.gov/pubmed/18720654.

[35] *Ibid.*, Tables 7 and 8.

[36] U.S. EPA, Critical Review of DIAL Emission Test Data for BP Petroleum Refinery in Texas City, Texas, November 2010, Table 2; available at https://www3.epa.gov/airtoxics/bp_dial_review_report_12-3-10.pdf.

Table 1: Comparison of DIAL Results and Tank Emissions Estimated Using AP-42

Source	Source Description	Compound	Average DIAL flux, lb/hr[a]	Estimated emissions using standard estimating procedures with actual conditions at the time of the DIAL test, lb/hr
Tanks 1020, 1021, 1024, and 1025	EFR[c] tanks storing crude oil	VOC	6.4[d]	1.3 – 1.9[e]
Tanks 1052, 1053, and 1055	EFR tanks storing crude oil	VOC	16.3[d]	1.8 – 2.3[e]
Tanks 501, 502, 503, and 504	EFR tanks storing light distillates	VOC	8.6[d]	3.0 – 3.9[e]
Tank 43	VFR[f] tank storing fuel oil #6	VOC	2	1.3
			9.3	1.3
Tanks 60, 63, 11, 12, 18, 42, 61, and 65	VFR and EFR tanks storing various products	VOC	9	0.6 – 9.1[e]
Tanks 54, 55, 56, and 98	VFR and EFR tanks storing various products	VOC	3.1[d]	0.3 – 9.7[e]
Tanks 53 and 55	VFR tanks storing diesel fuel	VOC	23.8[d]	4.8 – 5.2[e]

Others have similarly concluded that "[c]rude oil and heated oil tank emissions measured by DIAL were 5–10 times higher than estimated by TANKS."[37]

A recent study commissioned by the South Coast Air Quality Management District (SCAQMD) using real-time monitoring to measure the emissions of VOCs and other pollutants at six refineries and a tank farm confirmed these results.[38] Mobile optical measurements were made at the tank farm for eight days between September 28 and October 7, 2015, to estimate tank VOC and other emissions. The results of these measurements were compared with emissions reported to the SCAQMD in emission inventories, as required by their operating permits. The methods used to calculate VOC emissions from the tanks are the same as those used in the 2/17 Application. Tank emissions, for example, were calculated using the EPA model TANKS 4.09d.[39]

The FluxSense comparison demonstrated that VOC emissions were underestimated by an average factor of 6.2, ranging from 2.7 to 12 for the six facilities, compared to emissions reported to the SCAQMD. A factor of 6.2 means that the emission inventories underestimated VOC emissions by a factor of 6.2 compared to measured VOC emissions. This is consistent with results reported elsewhere for other facilities that also estimate their emissions using AP-42 and

[37] Rod Robinson, The Application of Differential Absorption Lidar (DIAL) for Pollutant Emissions Monitoring, January 2015, pdf 46; available at https://www.h-gac.com/board-of-directors/advisory-committees/regional-air-quality-planning-advisory-committee/documents/2015/Jan%2015/DIAL%20%202015%20Houston%20Meeting%20January%20(sent%20version).pdf.

[38] FluxSense Inc., Emission Measurements of VOCs, NO2 and SO2 from Refineries in the South Coast Air Basin Using Solar Occultation Flux and Other Remote Sensing Methods, Final Report, April 11, 2017 (FluxSense Report); available at https://www.courthousenews.com/wp-content/uploads/2017/06/FluxSense-Study.pdf.

[39] Public Notice Document, pdf 510, 511, 512-581.

other similar methods. Johansson et al. (2014), for example, reported that, "Despite some significant variations from year to year and from area to area, there is a clear pattern of measured VOC emissions (alkanes, ethane, and propene) exceeding reported emissions with almost an order of magnitude on average."[40] The majority of the VOC emissions originate from the tanks.

If the lower end of the FluxSense VOC range (an average factor of 2.7 underestimate) is used to correct VOC emissions reported for the tanks in the 2/17 Application, VOC emissions would increase from 248.51 ton/yr to 345.85 ton/yr.[41] Using this revised value in IGP's ozone impact analysis yields a MERP[42] of 1.05%,[43] which indicates a significant ozone impact. If an average VOC underestimate of 6.2 were used, the total VOC emissions increase to 546.26 ton/yr[44] and the MERP would rise to 1.26%,[45] which indicates a significant ozone impact. Thus, ozone impacts are significant, requiring mitigation, such as a more efficient tank scrubber system and the use of geodesic domes on the internal floating roof storage tanks.

2. VOC and NOx Emissions from construction and marine vessels were improperly omitted from the Ambient Air Quality Analyses.

The ambient air quality impact analysis required to satisfy the PSD requirement must include all sources of emissions relative to the pre-project conditions. The NSR Manual describes the required analysis as follows:[46]

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[40] Johansson et al. Emission measurements of alkenes, alkanes, SO2, and NO2 from stationary sources in Southeast Texas over a 5 year period using SOF and mobile DOAS. Journal of Geophysical Research: Atmospheres, 2014, p. 1983; available at http://onlinelibrary.wiley.com/doi/10.1002/2013JD020485/pdf

[41] FluxSense Report, Table 43 and Table 1 (adjusted to exclude the VOC emissions from non-tank sources): (248.51 - 57.26 + 2.7 x 57.26) = **345.85 ton/yr**.

[42] Memorandum from Richard A. Wayland, Air Quality Assessment Director, to Regional Air Division Directors, Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program, December 2, 2016.

[43] Revised MERP assumes a tank VOC underestimate of 2.7: (258.59 ton/yr NOx/375.9 ton/yr MERP) + (345.85 ton/yr VOC/948 ton/yr MERP) = 1.05%.

[44] FluxSense Report, Table 43 and Table 1 (adjusted to exclude the VOC emissions from non-tank sources): (248.51 - 57.26 + 6.2 x 57.26) = **546.26 ton/yr**.

[45] Revised MERP assuming a tank VOC underestimate of 6.2: (258.59 ton/yr NOx/375.9 ton/yr MERP) + (546.26 ton/yr VOC/948 ton/yr MERP) = 1.26%

[46] NSR Manual, p. D.4.

> The ambient air quality analysis projects the air quality which will exist in the area of the proposed source or modification during construction and after it begins operation. The applicant first combines the air pollutant emissions estimates for the associated growth with the estimates of emissions from the proposed source or modification. Next, the projected emissions from other sources in the area which have been permitted (but are not yet in operation) are included as inputs to the modeling analysis. The applicant then models the combined emissions estimate and adds the modeling analysis results to the background air quality to arrive at an estimate of the total ground-level concentrations of pollutants which can be anticipated as a result of the construction and operation of the proposed source.

The air quality analysis supplied by IGP did not include any construction emissions. It also did not include construction and operation emissions from new support equipment, including the natural gas pipeline spur (emissions from compressor, valves, connectors), the ASU required to supply oxygen,[47] or marine vessels and marine support equipment that will export the methanol. Marine vessels are typically a major source of NOx and VOC. Thus, the analysis has significantly underestimated air quality impacts.

D. <u>LDEQ's BACT Determinations and arbitrary and inaccurate</u>.

1. Overview of BACT.

As defined in the Clean Air Act and the Louisiana SIP, "best available control technology" means "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant." 42 U.S.C. § 7479(3); LAC 33:III.509.B.

Thus, BACT requires a case-by-case[48] analysis in order to determine the lowest emission rate for the pollutant in question for the source in question, reflecting the maximum degree of emissions reduction[49] that is achievable considering collateral factors such as cost, energy, and other environmental impacts.

By using the terms "maximum" and "achievable," the Clean Air Act sets forth a "strong, normative" requirement that "constrain[s]" agency discretion in determining BACT.[50] Pursuant to those requirements, "the most stringent technology is BACT" unless the applicant or Agency

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[47] Public Notice Document, pdf 459.

[48] 42 U.S.C. § 7479(3); NSR Manual, p. B.5.

[49] NSR Manual, pp. B.1-B.2, B.23.

[50] *Alaska DEC*, 540 U.S. at 485-86.

can show that such technology is not feasible or should be rejected due to specific collateral impact concerns.[51] The collateral impacts exception is a limited one, designed only to act as a "safety valve" in the event that "unusual circumstances specific to the facility make it appropriate to use less than the most effective technology."[52] If the Agency proposes permit limits that are less stringent than those for recently permitted similar facilities, the burden is on the applicant and agency to explain and justify why those more stringent limits were rejected.[53] The need to aim for the lowest limits achievable as part of a BACT analysis was emphasized by the Environmental Appeals Board (EAB), which stated in reversing a permit issuance:

> If reviewing authorities let slip their rigorous look at 'all' appropriate technologies, if the target ever eases from the 'maximum degree of reduction' available to something less or more convenient, the result may be somewhat protective, may be superior to some pollution control elsewhere, but it will not be BACT.[54]

BACT's focus on the maximum emission reduction achievable makes the standard both technology-driven and technology-forcing.[55] A proper BACT limit must account for both general improvements within the pollution control technology industry and the specific applications of advanced technology to individual sources, ensuring that limits are increasingly more stringent. BACT may not be based solely on prior permits, or even emission rates that other plants have achieved, but must be calculated based on what available control options and technologies can achieve for the project at issue and set standards accordingly.[56] For instance,

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[51] *Alaska Dep't of Envtl. Conserv. v. EPA*, 298 F.3d 814, 822 (9th Cir. 2002).

[52] *In re Kawaihae Cogeneration Project*, PSD Appeal Nos. 96-6, 96-10, 96-11, 96-14, 96-16, 7 E.A.D. 107, 117 (E.A.B. Apr. 28, 1997); *In re World Color Press, Inc.*, 3 E.A.D. 474, 478 (Adm'r 1990) (collateral impacts clause focuses on the specific *local* impacts); *In re Columbia Gulf Transmission Co.*, PSD Appeal No. 88-11, 2 E.A.D. 824, 827 (Adm'r 1989); NSR Manual at B.29.

[53] *In re Indeck-Elwood, LLC*, PSD Appeal 03-04, 13 E.A.D. 184-190 (E.A.B. Sept. 27, 2006); *In re Knauf Fiber Glass, GMBH*, PSD Permit No. 97-PO-06, 8 E.A.D. 121, 131-32 (E.A.B. Feb. 4, 1999).

[54] *In re: Northern Michigan University Ripley Heating Plant*, PSD Appeal No. 08-02, slip op. at 16 (EAB 2009) (hereinafter "*In re NMU*"); see also *Utah Chapter of Sierra Club*, 226 P.3d at 734-35 (remanding permit where there "was evidence that a lower overall emission limitation was achievable").

[55] NSR Manual, p. B.12 ("[T]o satisfy the legislative requirements of BACT, EPA believes that the applicant must focus on technologies with a demonstrated potential to achieve the highest levels of control"); pp. B.5 ("[T]he control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams…"); and B.16 ("[T]echnology transfer must be considered in identifying control options. The fact that a control option has never been applied to process emission units similar or identical to that proposed does not mean it can be ignored in the BACT analysis if the potential for its application exists.")

[56] An agency must choose the lowest limit "achievable." While a state agency may reject a lower limit based on data showing the project does not have "the ability to achieve [the limit] consistently," *In re Newmont*, PSD Appeal No. 05-04, 12 E.A.D. at 429, 443 (E.A.B. Dec. 21, 2005), it may only do so based on a detailed record establishing an adequate rationale, *see id.* Moreover, actual testing data from other facilities is relevant to establishing what level of control is achievable given a certain technology. *Id*. at

technology transfer from other sources with similar exhaust gas conditions must be considered explicitly in making BACT determinations.[57]

The BACT review "is one of the most critical elements of the PSD permitting process" because it determines the amount of pollution that a source will be allowed to emit over its lifetime.[58] As such, the BACT analysis must be "well documented," and a decision to reject a particular control option or a lower emission limit "must be adequately explained and justified."[59] While the applicant has the duty to supply a BACT analysis and supporting information in its application, "the ultimate BACT decision is made by the permit-issuing authority."[60] Therefore, LDEQ has an independent responsibility to review and verify the applicant's BACT analyses and the information upon which those analyses are based to ensure that the limits in any permit reflect the maximum degree of reduction achievable for each regulated pollutant.[61] As demonstrated below, LDEQ has failed to confirm that the Applicant's BACT analysis meets these standards, which it does not.

Information to be considered in determining the performance level representing achievable limits includes manufacturer's data, engineering estimates, and the experience of other sources.[62] The Applicant and agency must survey not only the U.S. EPA RACT/BACT/LAER Clearinghouse ("RBLC") database, as exclusively relied on here, but also many other sources, both domestic and foreign, including other agencies' determinations and (draft) permits, permit applications for other proposed plants, technology vendors, performance test reports, consultants, technical journal articles, etc.

The RBLC was exclusively relied on in the St. James Methanol Plant Application to determine BACT. The RBLC is a database that summarizes issued permits. Previous permitting decisions do not determine BACT. Even if they did, the RBLC is neither a comprehensive nor an up-to-date source of permits. Indiana, for example, in response to an EPA survey on its New

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*30. The word "achievable" does not allow a state agency to only look at past performance at other facilities, but "mandates a forward-looking analysis of what the facility [under review] can achieve in the future." *Id*. at *32. Thus, the agency cannot reject the use of a certain technology based on the lack of testing data for that technology, where the record otherwise establishes that the technology is appropriate as an engineering matter. NSR Manual, at B.5.

[57] NSR Manual, p. B.5.

[58] *In re Mississippi Lime*, 15 E.A.D. at 361; *In re Knauf*, 8 E.A.D. at 123-24.

[59] *In re Mississippi Lime*, 15 E.A.D. at 361; *In re Knauf.*, 8 E.A.D. at 131.

[60] *In re: Genesee Power Station Ltd. Partnership,* 4 E.A.D. at 832, 835.

[61] *See* 42 U.S.C. § 7479(3) ("permitting authority" makes BACT determination); 40 C.F.R. § 70.7(a)(5).

[62] NSR Manual, p. B.24.

Source Review permitting procedures, states: "The RBLC is helpful as a starting point – but the State rarely is able to rely on it without a follow up call to the permitting agency."[63]

This database was relied on in the St. James Methanol Plant BACT analysis without consulting the wide array of other sources that are normally used to determine BACT, which include other such databases (e.g., SCAQMD, CARB), control technology vendors, inspection and performance test reports, environmental consultants, and technical journals, reports and newsletters (*e.g.*, McIlvaine reports).[64]

Previous permitting decisions do not determine BACT. Similarly, BACT is not a contest in which the limit that gets the most hits in the RBLC wins. BACT is the lowest "achievable" emission rate for a source, not the lowest emission rate previously achieved or permitted by sources in the past. The purpose of BACT is to encourage the development of technology.[65] It requires the use of "the latest technological developments as a requirement in granting the permit," so as to "lead to rapid adoption of improvements in technology as new sources are built," rather than "the stagnation that occurs when everyone works against a single national standard for new sources."[66]

Further, BACT postings on the RBLC are voluntary. Many BACT determinations are never posted, and determinations that are posted are often posted long after the determination is made or are incomplete and inaccurate. A study of 28 state air pollution control agencies in the eastern half of the U.S. found that only 14% of the most recent BACT/LAER determinations made for gas turbines were included in the RBLC.[67] Another investigation by the Virginia Department of Environmental Quality concluded that the RBLC is missing about 60% of the data from permits issued nationwide.[68]

The NSR Manual[69] recommends that other sources be consulted, including guidelines of other districts, control technology vendors, new source review permits and associated inspection

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[63] New Source Review Program Review Questionnaire, Indiana, August 23-24, 2004, p. 21; Available at: https://yosemite.epa.gov/r5/r5ard.nsf/0/f1ae5c7a42355dc9862574c8006fd17b/$FILE/Appendix%20A.Questionnaire.pdf.

[64] The NSR Manual, p. B.24.

[65] S. Rep. No. 95-127, p. 18 and *Alabama Power v. Costle*, 636 F.2d 323, 372 (D.C. Cir. 1980).

[66] S. Rep. No. 95-127, p. 18.

[67] N.H. Hydari, A.A. Yousuf, and H.M. Ellis, Comparison of the Most Recent BACT/LAER Determinations for Combustion Turbines by State Air Pollution Control Agencies, AWMA Meeting, June 2002 (Fox Comments, Ex. 2, Attachment A).

[68] Virginia State Advisory Board, BACT Clearinghouse, September 2002, p. 8 (Fox Comments, Ex. 2, Attachment B).

[69] U.S. EPA, New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990 (NSR Manual), p. B.11; Available at: https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf.

and performance test reports, environmental consultants, trade literature, and EPA's New Source Review bulletin board.[70]

The U.S. EPA established the top-down process described in the NSR Manual in order to ensure that a BACT determination is "reasonably moored" to the Clean Air Act's statutory requirement that BACT represent the maximum achievable reduction.[71] While an agency is not required to utilize the top-down process, where it purports to do so, the process must be applied in a "reasoned and justified manner."[72] The Applicant in this case purports to use the top-down process.[73] As the U.S. Environmental Appeals Board ("EAB")[74] has explained:

> The NSR Manual's "top-down" method is simply stated: assemble all available control technologies, rank them in order of control effectiveness, and select the best. So fixed is the focus on identifying the "top," or most stringent alternative, that the analysis presumptively ends there and the top option selected — "unless" technical considerations lead to the conclusion that the top option is not "achievable" in that specific case, or energy, environmental, or economic impacts justify a conclusion that use of the top option is inappropriate.[75]

More specifically, the top-down BACT process typically involves the following five steps:

1. <u>Step 1: Identify All Available Control Options</u>

The first step in the BACT process is to identify "all potentially available control options."[76] The goal at this step is to cast as wide a net as possible so that a "comprehensive list of control options" is compiled.[77] As the EAB has emphasized, "available is used in its broadest sense under the first step and refers to control options with a 'practical *potential* for application to the emission unit under evaluation."[78] A control option is considered "available" if "there are sufficient data indicating (but not necessarily proving)" the technology "will lead to a demonstrable reduction in emissions of regulated pollutants or will otherwise represent

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[70] NSR Manual, p. B.11.

[71] *Alaska DEC*, 540 U.S. 461, 485 (2004).

[72] *Alaska Dep't of Envtl. Conserv.*, 298 F.3d at 822.

[73] EDMS 10329019, Preliminary Determination Summary, pdf 79; 2016 Application, pdf 677.

[74] The EAB is the U.S. EPA's supreme adjudicative body. *See* Changes to Regulations to Reflect the Role of the New Environmental Appeals Board in Agency Adjudications, 57 Fed. Reg. 5320 (Feb. 13, 1992). EAB decisions represent the position of the EPA Administrator with respect to the matters brought before it. *See Tenn. Valley Auth. v. EPA*, 278 F.3d 1184, 1198–99 (11th Cir. 2002) (finding EAB decision to be "final agency action").

[75] *In re NMU,* slip op. at 13.

[76] *In re Mississippi Lime,* slip op. at 11.

[77] *In re Knauf*, 8 E.A.D. at 130.

[78] *Id.* (emphasis in original).

BACT."[79] The definition of BACT requires that the options considered include "application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant."[80]

2. Step 2: Eliminate Technically Infeasible Options.

Step two of the BACT process involves evaluating the technical feasibility of the available options and eliminating those that are not feasible.[81] Feasibility focuses on whether a control technology can reasonably be installed and operated on a source given past use of the technology.[82] Feasibility is presumed if a technology has been used on the same or similar type of source in the past.[83] This step in the analysis has a purely technical focus and does not involve the consideration of economic or financial factors (including project financing).

3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

The next step in BACT process is to rank the available and feasible control technologies for each pollutant in order of effectiveness.[84] That is, for each pollutant, the most effective control option is ranked first, and relatively less effective options follow with the least effective option ranked last.

4. Step 4: Evaluate the Most Effective Controls and Document the Results

The fourth step in the BACT process is to evaluate the collateral economic, environmental and energy impacts of the various control technologies.[85] This step typically focuses on evaluating both the average and incremental cost-effectiveness of a pollution control option in terms of the dollars per ton of pollution emission reduced.[86] The point of this review is to either confirm the most stringent control technology as BACT, considering economic, environmental, or energy concerns, or to specifically justify the selection of a less stringent technology based on consideration of these factors.[87]

5. Step 5: Select BACT

The final step in the BACT process is to select the most effective control option remaining after Step 4. This option must represent the "maximum degree of reduction… that is

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[79] *In re Spokane Regional Waste-to-Energy Applicant*, 2 E.A.D. 809, slip op. at 22 (Adm'r June 9, 1989).

[80] 42 U.S.C. § 7479(3).

[81] NSR Manual at B.7; *Indeck-Elwood*, slip op. at 11.

[82] *Id*.; *In re Knauf*, 8 E.A.D. at 130.

[83] *Id*.

[84] *In re Mississippi Lime*, slip op. at 12.

[85] NSR Manual, B.26; *Indeck-Elwood*, slip op. at 12.

[86] *In re Mississippi Lime*, slip op. at 12.

[87] *Id.*

achievable" after "taking into account energy, environmental, and economic impacts and other costs."

As explained below, while the Applicant claims it followed the five-step, top-down BACT process, a review of the record indicates that it failed to follow this step for all pollutants and pollution control devices. Thus, the PSD and Title V permits fail to require BACT for all emission sources.

2. The BACT analysis for GHGe for the Plant's heaters and boilers is unsupported, arbitrary, and inaccurate.

The major sources of GHGe emissions are the in-line boilers and heaters, which emit 98% of the GHGe.[88] The LDEQ's and Applicant's GHG BACT analyses are seriously outdated and fail to recognize the progress in controlling GHGs over the past decade, thus failing to identify BACT for GHGs.

IGP's BACT analysis identifies carbon capture and sequestration (CCS) as an "emerging" technology to control GHGe. This technology captures CO_2 from combustion stacks, purifies it, compresses it, and ships it offsite for storage or use. IGP's and LDEQ's BACT analyses argue that this technology is not economically or technically feasible for the IGP Methanol Plant.[89] These analyses are outdated, superficial, and incorrect. BACT for GHGe from the ICP Methanol Plant is CCS for GHGe emissions from the heaters and boilers with either nearby storage or export and use for enhanced oil recovery (EOR).

First, the BACT analyses assert commercial scale CCS systems have only been demonstrated on high CO_2 concentration streams and not from combustion exhaust gas streams on anything other than slip streams at coal-fired power plants.[90] This is not correct. *See* Fox Comments, Exhibit 2. The BACT analyses admit that "[a] number of post-combustion carbon capture projects have taken place on slipstreams at coal-fired power plants. Although these projects have demonstrated the technical feasibility of small-scale CO2 capture on a slipstream of power plant's emissions using various solvent-based scrubbing processes," IGP argues they are not "available" for purposes of BACT on a full-scale plant. The BACT analyses also point to a number of Department of Energy (DOE) demonstration projects that were canceled.[91] However, the LDEQ and IGP fail to disclose all of the successes on similar facilities, thus presenting a biased and incorrect GHG BACT analysis.

Many similar facilities are in operation, construction, or development around the world. These are compiled in Fox Comments, Exhibit 2 to this petition and shown in Figure 1. In fact,

[88] Public Notice Document, pdf 883: (110,271 + 508,700)*4/2,533,377 = 0.98.

[89] Public Notice Document, pdf 77-79 and 274-279.

[90] Public Notice Document, pdf 78 and 275.

[91] Public Notice Document, pdf 78 and 275.

CCS is a proven technology that has been in use for over 40 years. CCS was developed not as BACT for GHGe emissions from industrial facilities, but to provide an economic source of CO_2 for use in enhanced oil recovery and other industrial purposes, such as in the beverage industry.[92] Further, there has been considerable progress in CCS development especially in 2017, in the United States, China, Japan, the Middle East and Europe, which is not recognized in the BACT analysis.[93] The CCS BACT analyses fail to acknowledge this recent experience.

Figure 1: CCS Facilities in Operation (17), Construction (4), and Development (16)

The Petra Nova Carbon Capture facility at Unit 8 of the coal-fired W. A. Parish power plant near Houston, for example, was retrofitted with a 1.4 Mt CO_2 (90% capture) post-combustion CO_2 capture facility that has been in operation since January 2017. This facility captures 1.4 Mt of CO_2 annually from a 240 MW slipstream from the 610 MW unit and sends it 82 miles by pipeline for on-shore EOR in Hilcorp's West Ranch Oil Field in Jackson County, Texas. The facility uses the KM-CDR process, developed by Mitsubishi Heavy Industries and the Kansai Electric Power Company, specifically designed for low cost and low energy-consuming CO_2 absorption and desorption.[94] The CO_2 concentration in the gas stream from a

[92] *See* 80 Fed. Reg. at 64,555 (October 23, 2015).

[93] Global CCG Institute, Major Strides in 2017 for CCS; available at https://www.globalccsinstitute.com/insights/authors/GlobalCCS%20Institute/2017/05/08/major-strides-2017-ccs?author=NjA3.

[94] Petra Nova Carbon Capture; available at http://www.globalccsinstitute.com/projects/petra-nova-carbon-capture-project.

coal-fired boiler is similar to the CO_2 concentration in gas streams from the IGP Methanol Plant's heaters and boilers.

Second, IGP's GHGe BACT analysis admits that an advantage of using CCS for the Plant is the location of a nearby CO_2 transport pipeline operated by Denbury that could transport recovered CO_2 to Texas oilfields. The LDEQ, on the other hand, failed to consider off-site use, looking only at on-site storage and incorrectly concluding there is none.[95]

Pipeline transport was eliminated by IGP because it chose not to rely on Denbury as it would not be subject to the IGPM operating permit. IGP argued that "Denbury could require economic compensation that IGPM must meet in order to comply with federally-enforceable operating permit conditions."[96] However, IGP could sell the captured CO_2 to Denbury to reduce or eliminate these costs, an option not considered. As EPA noted:[97]

> Geologic storage options include use of CO_2 in EOR operations, which is the injection of fluids into a reservoir after production yields have decreased from primary production in order to increase oil production efficiency. CO_2-EOR has been successfully used for decades at many production fields throughout the U.S. to increase oil recovery. The use of CO_2 for EOR can significantly lower the net cost of implementing CCS. The opportunity to sell the captured CO_2 for EOR, rather than paying directly for its long-term storage, improves the overall economics of the new generating unit.

Compensation for pipeline use is not unreasonable and is a cost that would ordinarily be included in a cost-effectiveness analysis. It is not a valid justification for eliminating a feasible technology. Further, IGP, a company with the resources to build the largest methanol plant in the world, could certainly negotiate acceptable conditions for the use of a nearby pipeline, a tiny fraction of the Plant cost. CCS plants in the United States that transport CO_2 by pipelines owned by others have succeeded in negotiating pipeline agreements; see, for example, Petra Nova.[98]

Third, CCS technology is technically and economically feasible at the IGP Methanol Plant. The EPA recently determined that CCS technology is a feasible, economic, and

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[95] Public Notice Document, pdf 78 ("Moreover, LDEQ finds CO2 storage at or near the site to be technically infeasible.")

[96] Public Notice Document, pdf 275-276.

[97] 80 Fed. Reg. at 64,566 (October 23, 2015).

[98] Petra Nova Carbon Capture; available at http://www.globalccsinstitute.com/projects/petra-nova-carbon-capture-project.

appropriate control technology for many steam boilers, similar to IGP's process boilers and heaters.[99] EPA determined that the cost of CCS is reasonable, assuming CO_2 storage in deep saline formations.[100] Further, EPA reported the cost, expressed as the levelized cost of electricity (LCOE) in $/MWh, for new natural gas combined cycle plants at the low end of the cost range (60–105 $/MWh).[101] Others estimated the LCOE for new natural gas combined cycle plants at $33 to $87/MWh,[102] contradicting LDEQ's assertion that CCS on natural gas sources would be much higher than other sources due to the lower concentrations of GHGs in the exhaust gases. EPA also found that plants in most parts of the country would have access to CO_2 storage in deep saline formations.[103] There is nothing in this record to distinguish the IGP Methanol Plant gas stream from heaters and boilers from those where EPA has concluded that CCS is economically and technically feasible. The EPA concluded:[104]

> The EPA reasonably expects that the costs of CCS will decrease over time as the technology becomes more widely deployed. Although, for the reasons that have been noted, we consider the current costs of CCS to be reasonable, the projected decrease in those costs further supports their reasonableness. The D.C. Circuit case law that authorizes determining the "best" available technology on the basis of reasonable future projections supports taking into account projected cost reductions as a way to support the reasonableness of the costs.

The LDEQ, on the other hand, relied on an outdated 2010 report to conclude that CCS was not cost effective, stating that EPA estimates the cost per ton of CO_2 avoided to be $103 ($114/tonne) for natural-gas-fired combined cycle power plants, where CO_2 concentrations are in the range of 3% to 4%,[105] comparable to levels in new natural gas combined cycle plants discussed above. However, the LDEQ did not present any basis for concluding that $103/ton is

[99] *See* 80 Fed. Reg. at 64,510 and 64,565 (October 23, 2015).

[100] *See id.* at 64,563, 64,566, and 64,572.

[101] *See id.* At 64,568, Table 10.

[102] 80 Fed. Reg. at 64,565 (October 23, 2015).

[103] *See id.* at 64,577, Figure 1.

[104] 80 Fed. Reg. at 64,565 (October 23, 2015).

[105] Public Notice Document, pdf 79.

not cost effective, nor disclosed the CO_2 concentration in the Plant's exhaust gases. Further, the LDEQ did not explain that the cost per tonne "captured," the relevant metric for BACT, ranges from $49/ton for IGCC to $95/ton for a new natural gas combustion plant, nor did it disclose that the report concluded that "[i]mprovements to currently available CO2 capture and compression processes are important in reducing the costs incurred for CO2 capture."[106] Those improvements have been developed and employed, as demonstrated by the active CCS projects summarized in Fox Comments, Exhibit 2.

Elsewhere, the LDEQ erroneously concluded that CO_2 storage "at or near the site to be technically infeasible." Dedicated sequestration was rejected by LDEQ due to the lack of suitable geologic reservoir (e.g., basalt formations, organic rich shale basins, un-mineable coal areas, and saline formations) or opportunities for enhanced oil recovery in the immediate vicinity of the facility."[107] In reaching this conclusion, the LDEQ cites the third edition of the Carbon Sequestration Atlas.[108] However, this Atlas is outdated. The 2015 edition shows many suitable storage formations in and around Plaquemines Parish, as illustrated in Figure 2.[109] This atlas shows Plaquemines Parish (including adjacent offshore areas) overlies or is near sedimentary basins, oil reservoirs, natural gas reservoirs, unmineable coal deposits, organic-rich shale basins, and off-shore CO_2 storage potential in Louisiana.[110] These formations have substantial CO_2 sequestration potential.[111]

Figure 2: Areas with CO2 Storage Potential Near Plaquemines Parish

Plaquemines Parish:

[106] CCSTF, Report of the Interagency Task Force on Carbon Capture and Storage, August 2010, p. 34; available at https://energy.gov/fe/downloads/ccstf-final-report.

[107] Public Notice Document, pdf 78.

[108] U.S. DOE, Carbon Sequestration Atlas of the United States and Canada, 3rd Edition, 2010, pp. 27-31; available at https://www.netl.doe.gov/KMD/CDs/atlasIII/2010atlasIII.pdf.

[109] National Energy Technology Laboratory, Carbon Storage Atlas, 5th Edition, August 20, 2015, pp. 24-31; available at https://www.netl.doe.gov/research/coal/carbon-storage/atlasv.

[110] *See* National Energy Technology Laboratory, Carbon Storage Atlas, 5th Edition, pp.24-31 (2015); available at https://www.netl.doe.gov/File%20Library/Research/Coal/carbon-storage/atlasv/ATLAS-V-2015.pdf.

[111] *Id.* at p.110 (2015).

Sedimentary Basins

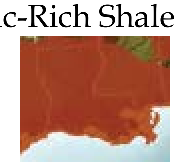
Oil Reservoirs

Natural Gas Reservoirs

Unmineable Coal

Saline Formations

Organic-Rich Shale Basins



Offshore CO2 Storage Potential

Fourth, IGP's BACT analysis includes a cost-effectiveness analysis for amine treatment and CO_2 transport that estimated the cost of capture and sequestration of CO_2 from heaters and boilers as $39.18/ton.[112] This BACT analysis eliminated CCS as not cost effective, compared to a range of $5 to $23 per short ton CO_2 removed.[113] However, no citation is provided for this range. Further, it apparently fails to include cost data for the 17 operating facilities tabulated in Fox Comments, Exhibit 2. Finally, the cost analysis grossly overestimates costs.

IGP's BACT analysis argues CCS works best for "high-purity CO2 streams," asserting additional equipment, such as amine treaters, are required to purify the combustion gases, which it asserts have not been demonstrated on a commercial scale.[114] The LDEQ's analysis also assumed impurities such as NOx that can degrade the CO_2 capture materials.[115] However, this is not correct on both counts. First, the amine treatment systems have been in use for decades and are demonstrated on many similar facilities. Second, this equipment, if required, would be based on a much smaller system than costed in Table 3-6 because the heaters and boilers that generate GHGe at the Plant will be equipped with controls to remove the pollutants—catalytic oxidation will remove over 90% of CO and VOCs and selective catalytic reduction (SCR) will remove over 90% of the NOx,[116] pollutants the amine system would be designed to remove. Thus, the resulting gas streams will be relatively clean compared to sources in the cited cost range and would not require purification to the extent assumed in the cost analysis. This avoids the majority of the assumed cleanup cost required before carbon capture can be implemented. The BACT analysis failed to take this into consideration and thus is fundamentally flawed.

Further, the assumptions used to calculate the capital recovery factor are not realistic. Given the current interest rate environment, an interest rate of 7% is unrealistic; 3% to 4% is more reasonable. Further, a 20-year life is too short for equipment that has a 40-year demonstration period; 30 years is more typically assumed and is more reasonable for equipment with a long operating history. The revised capital recovery factor, assuming an interest rate of

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[112] Public Notice Document, pdf 278, Table 3-6.

[113] Public Notice Document, pdf 277.

[114] Public Notice Document, pdf. 274-275.

[115] Public Notice Document, pdf 78.

[116] Public Notice Document, pdf 71.

4% and a 30-year equipment life, is 0.058,[117] which reduces the cost effectiveness of capture and sequestration from $39.18/ton to $24.1/ton, which is within the range cited in IGP's BACT analysis.

Fifth, the BACT analysis should have explored the possibility of obtaining some or all of the power required to operate the GHG control system on-site from renewables such as wind and solar. Fuel mix for a facility, especially in the context of GHGe emissions, is an appropriate consideration in the BACT analysis.

In sum, carbon capture is feasible and cost effective for the GHGe emissions from the Plant's heaters and boilers and must be required as BACT. Further, IGP's monetary investment in carbon capture and sequestration technology not as an economic cost but as a potential economic benefit must be determined. Like construction of other aspects of the proposed Plant, construction of the carbon capture and sequestration technology would mean a significant increase in IGP's investment in Plaquemines Parish. This type of investment will lead to more construction and process jobs, increase the tax base, and increase foreign direct investment in Plaquemines Parish and Louisiana, important benefits to consider when weighing the cost of a control.

3. The BACT determination for VOC emissions from the Methanol Tank Scrubbers is unsupported, arbitrary, and inaccurate.

The Plant includes two fixed roof buffer tanks in each methanol unit and several internal floating roof product tanks.[118] IGP concluded that BACT for VOC emissions from the fixed roof tanks is the use of a wet scrubber to recover methanol product with an efficiency of 95%, and from the internal floating roof tank, a wet scrubber with an efficiency of 98%.[119] However, LDEQ concluded that BACT for all of these tanks is a wet scrubber with an efficiency of 95%. The permits likewise only require a scrubber control efficiency of 95% for all the methanol storage tanks.[120]

The Application fails to provide any information on the ventilation system that would route methanol vapors to the scrubber or on the scrubber itself—such as the vendor, type, design flow rate, ventilation system control efficiency, etc. Similar facilities have proposed more efficient scrubbers. There are three major problems with this determination.

First, the five-step, top-down BACT analysis was not performed. Rather, a control efficiency was plucked out of thin air with no support whatsoever.

[117] $CRF = [i(1+i)^n/[(1+i)^n - 1] = [0.04(1 + 0.04)^{30}]/[(1+ 0.04)^{30}-1] = 0.058$.

[118] Public Notice Document, pdf 271.

[119] Public Notice Document, pdf 271, 273.

[120] Public Notice Document, pdf 42 (Condition 158), 43 (Condition 173).

Second, BACT is an emission limit, not a control efficiency, which is an intermediate step in establishing an emission limit. The BACT analysis failed to establish a BACT VOC emission limit for the scrubbers, which is required to satisfy Step 3 of the BACT analysis.

Third, the Application asserts the 95% control efficiency with no support. The NSR Manual requires the use of the most recent regulatory decisions and performance data for identifying the emissions performance level(s) to be evaluated in all cases.[121] Further, other information to be considered in determining the performance level representing achievable limits include**s** manufacturer's data, engineering estimates, and the experience of other sources. The applicant and agency must survey the RBLC and other sources, both domestic and foreign, including other agencies' determinations and (draft) permits, permit application**s** for other proposed plant**s,** technology vendors, performance test reports, consultants, technical journal articles, etc. None of these sources were consulted in determining BACT for the methanol tank scrubbers. A review of recent methanol plants indicates 95% VOC control is not BACT in this application.

The similar Kalama facility, proposed in Washington State, includes crude and product methanol tanks, vented to a wet scrubber. The Kalama application concluded:[122]

> **7.5 Proposed BACT Limits and Control Options**
> The use of fixed roof tanks for crude methanol storage and internal floating roof tanks for shift product and final product storage with all tanks being controlled by a water scrubber are proposed as BACT for the methanol storage tanks. The vapor control system will capture 99% of the VOC emissions and the water scrubbers will reduce VOC emissions by at least 99% for an overall control efficiency of 98% for the methanol storage tanks.

The Kalama control efficiency is based on manufacturer's information, which specifies a *minimum* capture efficiency of 99% for methanol vapors. The Southwest Clean Air Agency (SWCAA) agreed and established BACT CO permit limits of 0.72 ton/yr and 0.16 lb/hr, and VOC limits of 2.50 ton/yr and 0.57 lb/hr. [123] A final permit has been issued with these limits.[124]

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[121] NSR Manual, p. B.23.

[122] Kalama Application, pdf 191.

[123] Southwest Clean Air Agency, Technical Support Document, Air Discharge Permit ADP 16-3204, Draft, November 21, 2016, p. 16-17 (manufacturer specifications); available at http://www.swcleanair.org/docs/permits/prelim/16-3204TSD.PDF.

[124] Southwest Clean Air Agency, Air Discharge Permit 16-3204, June 7, 2017, Condition 11, p. 6; available at swcleanair.org/docs/permits/Final/16-3204ADP.PDF.

The similar Yuhuang methanol plant, located in St. James, Louisiana, includes three fixed roof, raw methanol tanks equipped with a closed vent system routed to a scrubber with a 98% control efficiency.[125]

In sum, VOC BACT for the methanol product tanks scrubbers should be VOC emissions based on 99% control.

4. The BACT analysis for VOC emissions from fugitive components is unsupported and invalid.

Fugitive emissions are leaks from valves, pressure relief devices (PRDs), connectors, pumps, and compressors. The LDEQ's and Applicant's BACT analyses concluded that BACT for VOC emissions from fugitive components is a leak detection and repair (LDAR) program that meets the requirements of 40 CFR 63 Subpart H, without conducting a top-down BACT analysis.[126] Complying with regulations that IGP must meet regardless of BACT does not satisfy BACT.

IGP evaluated three technologies to control fugitive emissions: (1) "zero leak" components"; (2) infrared camera monitoring; and (3) LDAR compliance programs. IGP's analysis of each is superficial and unsupported and thus fails to identify BACT.

First, IGP eliminated leakless components by arguing that their use "may be limited by materials of construction and process operating conditions, such as high temperatures." IGP also argued they "are not considered technically feasible on a facility-wide basis to replace standard pumps and valves."[127] However, IGP failed to supply any specific example or evidence from a vendor confirming their infeasibility.

Regardless, these arguments leave open the possibility of using leakless components in areas without process constraints, such as on piping connecting storage tanks. Compressors, for example, can be designed with a closed-vent system to capture and transport leakage from the compressor drive shaft seal back to a process or a fuel gas system or to a control device. The BACT analysis must evaluate these feasible options.

Second, there are many different versions of LDAR programs. IGP selected the version required by 40 CFR 63 Subpart H without considering any other LDAR option. A regulatory requirement that IGP must follow regardless of BACT does not necessarily satisfy BACT. It is merely the status quo.

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[125] Ramboll Environ, Application for a Minor Modification to Title V Permit No. 2560-00295-V0 Pdf 15, Yuhuang Chemical, Inc. Methanol Plant, June 2016 pdf 14-16, 116, Table 1-3 of EDMS Doc. No. 10239485 (Attachment F), available at http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=10239485&ob=yes&child=yes.

[126] Public Notice Document, pdf 77.

[127] Public Notice Document, pdf 268.

The most basic elements of an LDAR program are the definition of a leak (expressed as parts per million of the leaked substance), the frequency of monitoring, and the timeline in which leaks are repaired once discovered. The Bay Area Air Quality Management District (BAAQMD) has demonstrated that stricter regulation is feasible than what is contemplated in 40 CFR 63 Subpart H.

The BAAQMD supervises LDAR programs at five refineries with over 200,000 regulated components, as well as chemical plants, bulk plants, and bulk terminals under Regulation 8, Rule 18 (Reg 8-18). This regulation, first adopted in 1998, sets lower leak limits, more frequent inspections, and shorter repair schedules than required as BACT as summarized in Table 4, below.

Table 4: Comparison of Draft Permit LDAR Program with BAAQMD Rule 8-18

	40 CFR 63 Subpart H	BAAQMD Rule 8-18
Leak definition – valves in gas/vapor/light liquid services	500 ppm	100 ppm
Leak definition – pumps/compressors in light liquid service	1,000 ppm/500 ppm	500 ppm
Connectors in gas/vapor/light liquid services	500 ppm	100 ppm
Inspection frequency	Monthly/annual+	Quarterly/annual[128]
Repair schedule	15 days	7 days[129]

Another key aspect of an LDAR program is the scope of any exemptions recognized by the program. The LDAR program evaluated in the BACT analysis exempts leaks that are "unsafe" or "difficult" to monitor. The BAAQMD rule does not recognize such an exemption, as it is not consistent with BACT, given the BAAQMD's experience. The BACT analysis must include all feasible LDAR programs, including one as effective as is currently in use within the BAAQMD.

In particular, in order to avoid the need to monitor such unsafe equipment leaks, the Plant should be designed to minimize or eliminate them to the extent feasible. Any remaining components that qualify as difficult or unsafe to monitor or repair should be required to use

[128] Pumps are subject to daily visual inspection. If a valve has not been found to be leaking during five quarterly inspections, the inspection frequency is reduced to once per year.

[129] If the leak is detected by BAAQMD personnel during an inspection it must be repaired within 24 hours. The BAAQMD rules also require that leaks detected by the source be minimized within 24 hours.

leakless designs. This should be cost effective as (1) the cost of monitoring, repairing and re-monitoring devices that are difficult to monitor is substantially higher than components in more convenient locations; and (2) the potential emissions from leaking "inaccessible" components is greater as a leak is less likely to be observed visually or by sense of smell, and instrumented monitoring only occurs annually.

The BACT analysis also did not consider requiring that "repeat offenders" be replaced. The South Coast Air Quality Management District and the Ventura County Air Pollution Control District each have rules under which components that have been subject to repair more than, for example, five times within a year be replaced with BACT/BARCT or be vented to an approved air pollution control device.[130]

Finally, the LDEQ must ensure the integrity of any LDAR program. As U.S. EPA's history of enforcement actions demonstrates, this integrity cannot be taken for granted.[131] The U.S. EPA has encountered significant fraud in the conduct of LDAR inspections and in the reporting of results.[132] To avoid this, LDEQ must include safeguards in the permit, including requiring a licensed professional engineer to sign off on all LDAR reports. LDEQ must also explore requiring periodic independent audits of the LDAR program, at least for the largest emitters.

Third, the BACT analysis rejected the use of infrared camera monitoring due to alleged absence of methods to interpret and retain video records and detection limits higher than leak limits.[133] However, these claims are false. There are several recommended technologies and practices[134] that are applicable to equipment leaks and which have been widely used in the field

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[130] *See* SCAQMD Rule 1173(g)(3) and Ventura County APCD Rule 74.7. Under the Ventura County rule, for example, if a valve is found to have suffered five major leaks in a year it shall be replaced by a valve with a bellows seal, or with graphite, PTE or PTFE stack chevron seal rings, or with BACT technology level components.

[131] For a more recent example, *see* U.S. EPA's recent refinery settlements. *See, e.g.*, http://www.epa.gov/compliance/resources/cases/civil/caa/oil/index.html.

[132] In the late 1990s, EPA discovered flagrant, industry-wide violations of several CAA requirements at the nation's refineries. Among the most significant were LDAR rules violations where refiners, and independent contractors hired by refiners, routinely underreported by up to a factor of 10 the number of leaking valves, leading to significant excess emissions. The ensuing enforcement actions led to 29 settlements with operators of over 90% of the refining capacity in the country. These settlements required improved LDAR practices, $82 million in fines, and $75 million in Supplemental Environmental Projects. This experience demonstrates a need for detailed independent oversight of LDAR activities, as does the recent Pelican refinery criminal prosecution.

[133] Public Notice Document, pdf 268.

[134] *See, e.g.*, ENVIRON International Corporation, Literature Assessment of Remote Sensing Technologies for Detecting and Estimating Emissions for Flares and Fugitives, Prepared for Texas Commission on Environmental Quality, May 2008; available at

and required in EPA consent decrees and information collection to quantify emissions from fugitive and other sources.[135] Handheld infrared cameras have been used to identify, in real time, process components that are leaking.[136] Additional imaging technologies, including the use of DIAL (Differential Absorption Light Detection and Ranging), can also be used to identify fugitive sources of VOCs.[137] The existing LDAR program could be expanded to process units not currently covered (e.g., cooling towers).[138] These options must be evaluated as a part of a complete BACT analysis for fugitive VOC emissions from flanges. A recent study in California used remote sensing to identify leaks that would not be detected by a conventional LDAR program—a malfunctioning vent on an external roof of a tank and a leak in a buried pipe.[139]

Optical scanning programs can be a part of an overall improved LDAR program. Use of optical cameras involves some modest level of investment; however, once purchased, these devices can provide an extremely low-cost means of filling the gaps in the LDAR program. Daily or weekly scans can identify plant areas containing gross emitters (including "unsafe to monitor" or "difficult to monitor" components) for targeted LDAR inspections. Such inspections could replace scheduled inspections and save operators money by detecting leaks early, while improving the environmental performance of the Plant. Use of optical scanning devices, pressure relief valves, monitoring devices and other technical advances can complement existing programs. However, the suite of existing options has not demonstrated the ability to

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[135] Steven Ramsey, Shagun Bhat, and Ram Hashmonay, Optical Remote Sensing of Fugitive Emissions, Presentation at 2009 LA A&WMA Environmental Conference, October 28, 2009; available at la-awma.org/files/2009_3-4.pdf.

[136] *See*, *e.g.*, Technology Transfer: Optical Leak Imaging for the Hydrocarbon Industry, ICF Consulting; available at http://www.icfi.com/Markets/Environment/doc_files/optical-leak-imaging.pdf.

[137] *See*, *e.g.*, Refinery Demonstration of Optical Technologies for Measurement of Fugitive Emissions and for Leak Detection, Alberta Research Council, November 2006, available at http://www.arc.ab.ca/areas-of-focus/carbon-conversion-capture-and-storage/cccs-publications-and-resources/dial-emission-reports/; *see also* Fugitive VOC-emissions measured at Oil Refineries in the Province of Västra Götaland in South West Sweden, 2003, available at http://www.spectrasyne.ltd.uk/ROSEVOCreport.pdf.

[138] CARB, Reducing Greenhouse Gas Emissions from California Refineries, April 2008; available at http://www.capcoa.org/climatechange/upload/documents/Presentation-04-11-2008-WorkshopPresentationRefineries4-11.pdf. S*ee also* Texas Environmental Research Consortium, Project H7-A: Compilation of Information on Cooling Towers, Equipment Fugitive Leaks and Flares, November 30, 2003.

[139] FluxSense Report, pp. 91-92.

provide the level of emission reductions as can be obtained from well-designed and implemented LDAR programs. For this reason these options must be considered in addition to and not *in lieu of* existing programs.

CONCLUSION

For the foregoing reasons, EPA should object to the Proposed Title V Permit No. 2240-00452-V0 for IGP.

Respectfully submitted via EPA CDX on November 28, 2017 by:

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