

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
BEFORE THE ADMINISTRATOR**

IN THE MATTER OF	*	PETITION FOR
	*	OBJECTION
Clean Air Act Title V Permit No. 2560-00292-V1	*	
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	*	
for South Louisiana Methanol	*	Permit No. 2560-00292-V1
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Issued by the Louisiana Department of Environmental Quality	*	
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PETITION REQUESTING THAT THE ADMINISTRATOR OBJECT TO THE ISSUANCE OF THE PROPOSED MODIFIED TITLE V AIR PERMIT NO. 2560-00292-V1 ISSUED BY LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY TO SOUTH LOUISIANA METHANOL, LP FOR THE ST. JAMES METHANOL PLANT IN ST. JAMES, 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 and the Louisiana Environmental Action Network petition the Administrator of the United States Environmental Protection Agency (“EPA”) to object to the proposed modified Title V air operating air permit no. 2560-00292-V1 (“Title V Permit”) issued South Louisiana Methanol, LP for the St. James Methanol Plant in St. James, Louisiana. South Louisiana Methanol has not yet commenced construction of the plant.

Petitioners respectfully request that the Administrator object to the Title V Permit for the St. James Methanol Plant because it does not comply with the requirements of the Clean Air Act as demonstrated below.

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). As shown below, Petitioners demonstrate that the Title V permit issued to South Louisiana Methanol does not comply with the Act’s requirements.

I. STATUTORY & REGULATORY FRAMEWORK

Section 502(d)(1) of the Clean Air Act, 42 U.S.C. § 7661a(d)(1), requires each state to develop and submit to EPA an operating permit program intended to meet the requirements of Title V of the Act. Louisiana’s approved Title V program is incorporated into the Louisiana Administrative Code at LAC 33:III.507.

Any person wishing to construct a new major stationary source of air pollutants must apply for and obtain a Title V permit before commencing construction. 42 U.S.C. § 7661b(c); *see also* LAC 33:III.507.C.2.1. The Title V permit 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). The Title V operating permit program does not generally impose new substantive air quality control requirements (i.e., “applicable 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). A central purpose of the Title V program is to “enable the source, states, EPA, and the public to better understand the requirements to which the source is subject, and whether the source is meeting those requirements.” *Id.* Thus, the Title V operating permits program is a vehicle for ensuring that existing air quality control requirements are appropriately applied to facility emission units and that compliance with these requirements is assured.

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.

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 (identifying EPA approved regulations in the Louisiana SIP). The Louisiana PSD regulations apply to the construction of a “major stationary source,” which include certain listed sources, such as a chemical process plant like the St. James Methanol Plant, 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 (“SO₂”), particulate matter (“PM”), volatile organic compounds (“VOC”), carbon monoxide (“CO”), and greenhouse gases. *Id.* “Potential to emit” is “the maximum capacity of a stationary source to emit a pollutant under its physical and operational design.” 33 LAC Pt III, § 509. “Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.” *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). These requirements include (1) an analysis of whether the source will cause a violation of any national ambient air quality standard (“NAAQS”); (2) application of the best available control technology (“BACT”) for each PSD regulated pollutant emitted from the facility; and (3) an opportunity for the public to participate in the process. 40 U.S.C. § 7475(a)(2)-(8); see also *Alaska Dep't of Env'tl. Conservation v. EPA*, 540 U.S. 461, (2004). The purposes of requiring PSD review are, among other things, “(1) to protect public health and welfare from any actual or potential adverse effect which ... may reasonably be anticipated to occur from air pollution, notwithstanding attainment and maintenance of all national ambient air quality standards; ... (3) to insure that economic growth will occur in a manner consistent with the preservation of existing clean air resources; ... and (5) to assure that any decision to permit increased air pollution 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 decisionmaking process.” 42 U.S.C. § 7470.

Louisiana PSD regulations command: “No new major stationary source . . . to which the requirements of Subsection J-Paragraph R.5 of this Section apply shall begin actual construction without a permit that states the major stationary source . . . will meet those requirements.” LAC 33:III.509(A)(3). Title V permits must incorporate the terms and conditions of the PSD permit where a PSD permit is required. If the Title V permit does not incorporate the terms and conditions of a required PSD permit, the Title V permit is not in compliance with the Clean Air Act.

The Clean Air Act mandates that EPA “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). 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.”² Because the permit at issue fails to comply with the Clean Air Act’s requirements, EPA has a “duty to object to [the] non-compliant.” See *New York Public Interest Group v. Whitman*, 321 F.3d 316, 332-34, n12 (2nd Cir. 2003).

¹ In the Matter of 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 *Id.* (citing 68 Fed. Reg. 9,892 (March 3, 2003) and 63 Fed. Reg. 13,795 (March 23, 1998))

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).

II. SIERRA CLUB AND LEAN MEET THE PROCEDURAL REQUIREMENTS FOR THIS TITLE V PETITION.

On September 30, 2015, SLM submitted an application for major modification of the PSD permit No. PSD-LA780 and Title V permit no. 2560-00292-V0. In addition, South Louisiana Methanol submitted additional information in support of its application for permit modification dated January 14, 2016, February 18, 2016, February 26, 2016, March 3, 2016, May 23, 2016, June 15, 2016, June 24, 2016, and July 1, 2016. LDEQ issued proposed PSD permit No. PSD-LA780(M-1) and Title V permit no. 2560-00292-V1 for public comment on December 1, 2016.³ The public comment period for the proposed permits ends on January 23, 2017. *Id.* Petitioners filed timely public comments with LDEQ regarding the proposed permits on December 28, 2016.

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 proposed Title V permit no. 2560-00292-V1 to EPA Region 6 on September 16, 2016. 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 permit within its 45-day review period, which ended on October 30, 2016.

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). Petitioners file this Petition within 60 days after the expiration of the Administrator's 45-day review period. 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). Petitioners base this petition on the comments prepared by Phyllis Fox, Ph.D., PE and submitted on their behalf during the public comment period. Dr. Fox's curriculum vitae and the comments that she prepared and submitted to LDEQ on behalf of Petitioners are attached as Exhibits 1 and 2, respectively.

³<http://www.deq.louisiana.gov/apps/pubNotice/show.asp?qPostID=9063&SearchText=methanol&startDate=1/1/2016&endDate=12/29/2016&category=>

III. BACKGROUND

Southern Louisiana Methanol, LP (“SLM” or the “Applicant”) has requested a major modification to their initial Part 70 operating permit No. 2560-00292-V0 and Prevention of Significant Deterioration (“PSD”) Permit No. PSD-LA-780 for the proposed St. James Methanol Plant (also referred to as the “Project” or “SJMP”), issued December 23, 2013 and PSD Permit amended June 3, 2015. The Project, a new methanol manufacturing facility near the town of St. James, will be designed to produce 5,275 metric tons per day (MTPD) of refined Grade AA methanol from natural gas and CO₂.⁴ The modifications include the following:⁵

- Increase methanol production from 5,150 MTPD to 5,275 MTPD;
- Use the Econamine CO₂ recovery process to capture and use 1,737 ton/day of CO₂ from the reformer offgas to produce methanol, rather than importing CO₂ by pipeline;
- Increase reformer firing rate from 2,434 MMBtu/hr to 3,148 MMBtu/hr to generate 30 MW of power;
- Increase methanol production to 5,275 MTPD;
- Increase auxiliary boiler firing rate, to support the Econamine Unit;
- Vent the crude methanol tank to a scrubber that removes 95% of the VOC emissions;
- Add a 41,000 gallon methanol product surge tank; and
- Add an Econamine cooling tower.⁶

These changes increased criteria pollutant emissions as summarized in Table 1. The facility is a major source under the PSD program and triggers PSD review for all criteria

⁴EDMS 10329019, Public Notice, pdf 1; Briefing Sheet, pdf 4.

⁵ EDMS 10329019, Briefing Sheet, pdf 11-13.

⁶ EDMS 10329019, pdf 615.

pollutants except SO₂.⁷ Thus, best available control technology (BACT) is required for all pollutants except SO₂.

Table 1: Estimated Change in Emissions due to Project.⁸

<u>Pollutant</u>	<u>Before</u>	<u>After</u>	<u>Change</u>
PM ₁₀	86.35	127.32	+40.97
PM _{2.5}	82.89	121.11	+38.22
SO ₂	6.63	10.18	+3.55
NO _x	138.63	221.62	+82.99
CO	98.92	273.17	+174.25
VOC *	70.32	137.66	+67.34
CO ₂ e	1,303,228	1,389,582	+86,354

The Louisiana Department of Environmental Quality (LDEQ) assembled relevant documents supporting the revised permits into a single 974 page long file, captioned “Material Associated with Proposed Permits for Public Review (Permit # 2560-00292-V1; Permit #PSD-LA-780(M1)), EDMS Doc. Id. 10329019, Sept. 15, 2016” on LDEQ’s website (“EDMS

⁷ EDMS 10329019, Briefing Sheet, pdf 16.

⁸ EDMS 10329019, Briefing Sheet, pdf 14.

10329019”), <http://edms.deq.louisiana.gov/app/doc/queryresults.aspx>. This document will be cited herein by pdf page number. This document consists of the following information:

- Public Notice, pdf 1-3
- Air Permit Briefing Sheet, Part 70 Operating Permit, pdf 3-38
- Specific Requirements, pdf 39-66
- General Information, pdf 67
- Letter re PSD Permit, pdf 68-69
- Briefing Sheet, pdf 70-75
- Preliminary Determination Summary, pdf 76-119
- Specific Conditions, pdf 120-123
- Table I: BACT Cost Summary, pdf 124-129
- Table II: Air Quality Analysis Summary, pdf 130
- Worksheet for Technical Review of Working Draft of Proposed Permit, pdf 131-134
- Statement of Basis, pdf 135-167
- Public Notice, pdf 168-169
- September 2015 Permit Application, pdf 170-598
- Miscellaneous Correspondence, pdf 599-600
- Ozone Impact Analysis, pdf 601-605
- Miscellaneous E-Mails Re Emissions & Modeling, pdf 606-647
- January 2016 Permit Application, pdf 648-974

IV. THE PERMITS FAIL TO PROPOSE EMISSION LIMITS THAT REFLECT THE USE OF BEST AVAILABLE CONTROL TECHNOLOGY

The Clean Air Act requires that a permit issued to a major new source of air pollution in an attainment area include emission limits that reflect the installation of BACT for each regulated air pollutant.⁹ A permit cannot issue without proper BACT limits.¹⁰ The limits proposed in the draft permits do not represent BACT because they fail to reflect the maximum emission reductions that are achievable.

Under the Clean Air Act, BACT is defined as:

“ 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

⁹ 42 U.S.C. §§ 7471, 7475(a)(2), 7479(3); 40 C.F.R. 51.21(j)(2).

¹⁰ 42 U.S.C. § 7475(a)(4); *Alaska Dep't of Env'tl Conservation v. EPA*, 540 U.S. 461 (2004) (hereinafter “*Alaska DEC*”) (upholding U.S. EPA’s authority to block a PSD permit where the state permitting authority’s BACT determination was unreasonable).

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.”¹¹

Thus, BACT requires a case-by-case¹² 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 reduction¹³ 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.¹⁴ Pursuant to those requirements, “the most stringent technology is BACT” unless the applicant or Agency can show that such technology is not feasible or should be rejected due to specific collateral impact concerns.¹⁵ 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.”¹⁶ 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.¹⁷ 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.”¹⁸

¹¹ 42 U.S.C. § 7479(3).

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

¹³ NSR Manual, pp. B.1-B.2, B.23.

¹⁴ *Alaska DEC*, 540 U.S. at 485-86.

¹⁵ *Alaska Dep’t of Env’tl. Conserv. v. EPA*, 298 F.3d 814, 822 (9th Cir. 2002).

¹⁶ *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.

¹⁷ *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).

¹⁸ *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”).

BACT's focus on the maximum emission reduction achievable makes the standard both technology-driven and technology-forcing.¹⁹ 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.²⁰ For instance, technology transfer from other sources with similar exhaust gas conditions must be considered explicitly in making BACT determinations.²¹

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.²² 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."²³ 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."²⁴ 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.²⁵ As demonstrated below, LDEQ has failed to confirm that the Applicant's BACT analysis meets these standards, which it does not.

¹⁹ 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.")

²⁰ 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 *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.

²¹ NSR Manual, p. B.5.

²² *In re Mississippi Lime*, 15 E.A.D. at 361; *In re Knauf*, 8 E.A.D. at 123-24.

²³ *In re Mississippi Lime*, 15 E.A.D. at 361; *In re Knauf*, 8 E.A.D. at 131.

²⁴ *In re: Genesee Power Station Ltd. Partnership*, 4 E.A.D. at 832, 835.

²⁵ *See* 42 U.S.C. § 7479(3) ("permitting authority" makes BACT determination); 40 C.F.R. § 70.7(a)(5).

Information to be considered in determining the performance level representing achievable limits includes manufacturer's data, engineering estimates, and the experience of other sources.²⁶ 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 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."²⁷

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).²⁸

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.²⁹ 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."³⁰

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.³¹ Another investigation by the Virginia

²⁶ NSR Manual, p. B.24.

²⁷ 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](https://yosemite.epa.gov/r5/r5ard.nsf/0/f1ae5c7a42355dc9862574c8006fd17b/$FILE/Appendix%20A.Questionnaire.pdf).

²⁸ The NSR Manual, p. B.24.

²⁹ S. Rep. No. 95-127, p. 18 and *Alabama Power v. Costle*, 636 F.2d 323, 372 (D.C. Cir. 1980).

³⁰ S. Rep. No. 95-127, p. 18.

³¹ 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 (Ex. 2, Attachment A).

Department of Environmental Quality concluded that the RBLC is missing about 60% of the data from permits issued nationwide.³²

The NSR Manual³³ recommends that other sources be consulted, including guidelines of other districts, control technology vendors, new source review permits and associated inspection and performance test reports, environmental consultants, trade literature, and EPA's New Source Review bulletin board.³⁴ The LDEQ should stop the clock on this permit and do a thorough review of best available control technology, consulting the full range of required sources.

A. BACT is Typically Evaluated Through a 5-Step, Top-Down Process

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.³⁵ 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."³⁶ The Applicant in this case purports to use the top-down process.³⁷ As the U.S. Environmental Appeals Board ("EAB")³⁸ 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.³⁹

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

³² Virginia State Advisory Board, BACT Clearinghouse, September 2002, p. 8 (Ex. 2, Attachment B).

³³ 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>.

³⁴ NSR Manual, p. B.11.

³⁵ *Alaska Dept. of Env't'l Conservation v. EPA*, 540 U.S. 461, 485 (2004).

³⁶ *Alaska Dep't of Env'tl. Conserv.*, 298 F.3d at 822.

³⁷ EDMS 10329019, Preliminary Determination Summary, pdf 79; 2016 Application, pdf 677.

³⁸ 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").

³⁹ *In re NMU*, slip op. at 13.

1. Step 1: Identify All Available Control Options

The first step in the BACT process is to identify “all potentially available control options.”⁴⁰ The goal at this step is to cast as wide a net as possible so that a “comprehensive list of control options” is compiled.⁴¹ 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.”⁴² 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 BACT.”⁴³ 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.”⁴⁴

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.⁴⁵ Feasibility focuses on whether a control technology can reasonably be installed and operated on a source given past use of the technology.⁴⁶ Feasibility is presumed if a technology has been used on the same or similar type of source in the past.⁴⁷ 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.⁴⁸ 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.⁴⁹ This step typically

⁴⁰ *In re Mississippi Lime*, slip op. at 11.

⁴¹ *In re Knauf*, 8 E.A.D. at 130.

⁴² *Id.* (emphasis in original).

⁴³ *In re Spokane Regional Waste-to-Energy Applicant*, 2 E.A.D. 809, slip op. at 22 (Adm’r June 9, 1989).

⁴⁴ 42 U.S.C. § 7479(3).

⁴⁵ NSR Manual at B.7; *Indeck-Elwood*, slip op. at 11.

⁴⁶ *Id.*; *In re Knauf*, 8 E.A.D. at 130.

⁴⁷ *Id.*

⁴⁸ *In re Mississippi Lime*, slip op. at 12.

⁴⁹ NSR Manual, B.26; *Indeck-Elwood*, slip op. at 12.

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.⁵⁰ 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.⁵¹

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 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. Some examples follow. The errors identified in the examples listed below are present in all of the BACT determinations for all pollutants and sources at the St. James Methanol Plant in the Application and LDEQ’s Statement of Basis and Preliminary Determination. All of the BACT determinations fail to identify all feasible control technologies, omitting the most effective, and all eliminate the top technology based on unsupported and incorrect energy, environmental and/or economic impacts. Thus, the entire BACT analysis, for all sources and pollutants, should be rejected and redone, following the above outlined top-down process.

B. BACT for Greenhouse Gases (GHG) Emissions

Combustion sources (boilers, reformer) emit greenhouse gases, including carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O). These are generally expressed as carbon dioxide equivalents (CO₂e) and summed to estimate total CO₂e. Over 99% of the CO₂e from gas-fired sources is CO₂. A BACT determination for GHG should be conducted in the same manner as for any other PSD pollutant, in accordance with the NSR Manual.⁵²

The January 2016 Application includes a GHG BACT analysis for the natural gas fired reformer and boilers.⁵³ The BACT analysis considered only two control technologies, carbon capture and storage (CCS) and energy efficiency measures.⁵⁴ Carbon capture and storage is a process that uses adsorption or absorption to remove CO₂ from flue gas, with subsequent desorption to produce a concentrated CO₂ stream. The recovered CO₂ is then compressed and

⁵⁰ *In re Mississippi Lime*, slip op. at 12.

⁵¹ *Id.*

⁵² U.S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, March 2011 (GHG Guidance); Available at: <https://www.epa.gov/sites/production/files/2015-07/documents/ghgguid.pdf>.

⁵³ EDMS 10329019, January 2016 Application, Section 3.2.5, pdf 690-698.

⁵⁴ EDMS 10329019, January 2016 Application, Table 3.12, pdf 695.

transported to an end use, such as enhanced oil recovery or as a chemical feedstock for rubber, plastics and fertilizers, for freezing foods, and in various refrigeration applications. If no end use is available, the CO₂ is stored, most likely in an underground geological storage reservoir such as a deep saline aquifer or a depleted oil well or coal seam.

There are three major flaws with the Applicant's GHG BACT analysis. First, it did not consider all feasible control technology. Second, it improperly eliminated CCS based on environmental impacts. Third, it improperly eliminated CCS based on capital cost without considering cost effectiveness of other similar projects. Each of these flaws is discussed below.

1. The GHG BACT Analysis Did Not Consider All Feasible Control Technologies

The BACT analysis only evaluated two control options, CCS and energy efficiency measures. The purpose of Step 1 of the top down analysis is "to identify all control options with potential application to the source and pollutant under evaluation."⁵⁵ The NSR Manual identifies three categories of controls: (1) inherently lower-emitting processes (energy efficiency measures); (2) add-on control (CCS); and (3) combinations of inherently lower emitting processes and add-on controls.⁵⁶ The BACT analysis failed to include any controls from group 3. This is a fatal flaw as the combination of energy efficiency measures and CCS would significantly reduce GHG as well as other criteria pollutants that the Applicant argues would increase using CCS alone, causing a significant collateral environmental impact. The alleged "significant" collateral impact associated with CCS could be eliminated by combining CCS and energy efficiency measures.

2. The GHG BACT Analysis Improperly Eliminated CCS Based on Environmental Impacts

The January 2016 Application asserts that "[t]he increase in energy required to process the CO₂ would...greatly increase emissions of combustion pollutants such as PM, NO_x, CO, SO₂, VOC, and hazardous air pollutants such as acetaldehyde. It is questionable whether a system sized large enough to capture the CO₂ emissions would pass Louisiana Ambient Air Standards. Such a system would have an environmental impact to the immediate area and potentially require further control of VOCs increasing the capital and annualized cost."⁵⁷ LDEQ's Preliminary Determination Summary parrots this argument verbatim, adding nothing to this unsupported claim.⁵⁸

The record fails to make the demonstration of adverse impacts required under the top-down BACT process. The Applicant's and LDEQ's speculation as to whether a CCS system would pass Louisiana Ambient Air Standards is not a valid basis for eliminating this technology. In fact, the LDEQ demonstrates that CCS produces ten times less CO₂ per MMBtu of fuel fired (5.30 kg/MMBtu) than energy efficiency measures (53.1 kg/MMBtu). Thus, ten times more

⁵⁵ NSR Manual, p. B.10.

⁵⁶ *Id.*

⁵⁷ EDMS 10329019, January 2016 Application, pdf 696.

⁵⁸ EDMS 10329019, Preliminary Determination Summary, pdf 84, 86.

combustion emissions (and hence PM, NO_x, CO, SO₂, VOC) will be generated by energy efficiency measures than by CCS for an equivalent amount of CO₂ reduction, demonstrating a huge net environmental benefit and refuting its adverse impact claims. Further, the failure to reduce GHG results in compelling public health and welfare impacts.⁵⁹

The record asserts that CCS would increase emissions of other pollutants. However, it fails to estimate the increase and demonstrate that this increase results in a significant impact. The NSR Manual states “[t]he applicant is responsible for presenting an evaluation of each impact along with appropriate supporting information. Consequently, both beneficial and adverse impacts should be discussed and, where possible, quantified.”⁶⁰ Further, the NSR Manual notes that “[i]n the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding needs to be fully documented for the public record.”⁶¹ The record contains no such documentation.

The EPA GHG Guidance indicates that “Permitting authorities should ensure that the BACT requirement contained in the final PSD permit are supported and justified by the information and analysis presented in a thorough and complete permit record. The record should clearly explain the reasons for selection or rejection of possible control and emissions reductions options and include appropriate supporting analyses.”⁶²

This record contains no support for the assertion that emissions would increase or any evidence that if they do increase, that the increase would result in a significant environmental impact. Further, it fails to quantify the increase, which is feasible here as the applicant is proposing to use the very same process to recover CO₂ for process use. The record must demonstrate that any increase in emissions of other pollutants results in an adverse impact by performing air dispersion modeling and a health risk assessment. Absent the demonstration of a significant impact, CCS is the top technology and must be required as BACT.

First, the allegation as to adverse impacts relates only to the increase in energy (“[t]he increase in energy required to process the CO₂ would...greatly increase emissions”). The cost analysis indicates that 30 MW of power would be required to operate the CCS system.⁶³ It is simply not believable that the production of 30 MW of power would violate ambient air standards as this is a very small power plant. The ozone analysis, for example, demonstrated that the proposed emissions from the entire Project would result in a “negligible” impact on ozone due to the Project’s increase VOC and NO_x increases.⁶⁴ A 30 MW power plant would produce a tiny fraction of total Project emissions.

⁵⁹ GHG Guidance, p. 40.

⁶⁰ NSR Manual, p. B.26.

⁶¹ NSR Manual, pp. B.26 and B.29.

⁶² GHG Guidance, p. 20.

⁶³ EDMS 10329019, 2016 Application, pdf 697.

⁶⁴ EDMS 10329019, 2016 Application, pdf 605 (“operations at the proposed facility should have a negligible impact on ozone values....”).

Second, the NSR Manual explains that “the analysis of environmental impacts starts with the identification and quantification of the solid, liquid, and gaseous discharges from the control device or devices under review.”⁶⁵ There has been no “quantification” here. The NSR Manual continues: “Initially, a qualitative or semi-quantitative screening is performed to narrow the analysis to discharges with potential for causing adverse environmental effects. Next, the mass and composition of any such discharges should be assessed and quantified to the extent possible, based on readily available information.”⁶⁶ The record does not quantify criteria and HAP emissions, estimate resulting ambient concentration, or perform a health risk assessment. Thus, there is no evidence that any increase would be significant.

Third, for a technology such as the Econamine process that has been applied to similar facilities elsewhere (See Comment II), the applicant must demonstrate unusual circumstances at the proposed facility that create greater problems than experienced elsewhere.⁶⁷ The Econamine process is in wide use elsewhere. See Comment II.B.5. The record contains no discussion of unusual circumstances.

Fourth, the Briefing Statement argues that when an Econamine unit is used to produce CO₂ to use in methanol production, the increase in emissions will be mitigated through the use of BACT.⁶⁸ There is no reason why BACT would not also be used to control emissions from the Econamine unit when used to control CO₂. A BACT analysis is required for all pollutant-emitting equipment, not just “process” equipment. Further, the same equipment used to supply the Econamine unit to produce CO₂ could be sized to support additional CO₂ removal to satisfy BACT for CO₂ as well as criteria pollutants. This would reduce the unit cost of the Econamine unit as unit costs decline as the throughput increases.

Fifth, even assuming an increase in criteria and HAP emissions, if the BACT analysis had included the top BACT technology, CCS plus energy efficiency, which it failed to analyze, and LDEQ required MACT, the increase in criteria and HAP emissions would not be significant as 90%+ of the increase would be controlled. For example, if a 30-MW gas turbine were used to generate 30 MW of power to support a CCS system,⁶⁹ the increase in criteria and HAP emissions would be de minimis.

3. The GHG BACT Analysis Improperly Eliminated CCS Based On Economic Impacts

The Project’s BACT analysis concludes: “SLM has chosen to utilize energy efficiency measures rather than the cost-prohibitive carbon capture system as BACT for CO₂e.”⁷⁰ The LDEQ, based on the Applicant’s analysis, concluded that “...CCS is considered cost

⁶⁵ NSR Manual, p. B.47.

⁶⁶ NSR Manual, p. B.48.

⁶⁷ NSR Manual, p. B.47.

⁶⁸ EDMS 10329019, pdf 11.

⁶⁹ EDMS 10329019, January 2016 Application, pdf 697 (“Power, 30 MW”).

⁷⁰ EDMS 10329019, January 2016 Application, pdf 698.

prohibitive.”⁷¹ The Applicant does not get to “choose” the technology it uses as BACT, but rather must adopt the technology that satisfies the five-step, top-down BACT analysis, which is CCS plus energy efficiency measures. The rationale laid out in the BACT analysis and adopted by LDEQ for rejecting CCS is inconsistent with BACT and the top down BACT process the Application asserts it used for eliminating a control technology based on cost.

The Project will use the Econamine system to separate and capture 722,700 ton/yr of CO₂ from reformer offgases to use in the production of methanol.⁷² However, the LDEQ attempts to discriminate this use by asserting it is not “a control device” and proceeds to argue that the very same process when used to recover additional CO₂ from the balance of the reformer offgases and boilers is not cost effective as BACT. The economic arguments used to eliminate the Econamine system⁷³ as BACT violate the top-down BACT process and are meritless. In fact, CO₂e carbon capture and storage is highly cost effective. The Applicant and LDEQ have eliminated it based on invalid capital cost arguments and a cost analysis riddled with errors.

4. LDEQ Must Consider the Average Cost Effectiveness of CCS Compared to the Costs Borne by Other Similar Facilities

The record contains a GHG cost effectiveness analysis,⁷⁴ but does not use it to reject CCS. Instead, the record excludes CCS as BACT based on increases in capital costs, rather than cost effectiveness in dollars per ton of GHG removed. The Application argues that the additional equipment required to capture CO₂ from the reformer and boiler would increase annual capital cost by \$46 million/year and total annual costs by \$76.5 million/year.⁷⁵ This rationale does not meet BACT requirements to reject a technology for adverse economic impacts, which must be based on dollars per ton of pollutant removed.

The NSR Manual expressly rejects this type of conclusion without more analysis. “[T]he capital cost of a control option may appear excessive when presented by itself or as a percentage of the total project cost. However, this type of information can be misleading.”⁷⁶ Cost considerations in determining BACT should be expressed in terms of average cost effectiveness.⁷⁷ On its face, the LDEQ’s conclusion that CCS would increase the annual capital cost is an invalid basis for rejecting CCS as BACT in step 4 of the top-down BACT analysis.

When determining if the most effective pollution control option has sufficiently adverse economic impacts to justify rejecting that option and establishing BACT as a less effective

⁷¹ EDMS 10329019, Preliminary Determination Summary, pdf 84/85.

⁷² EDMS 10329019, January 2016 Application, pdf 695.

⁷³ EDMS 10329019, pdf 82-84; Preliminary Determination Summary, pdf 84-86.

⁷⁴ EDMS 10329019, January 2016 Application, Table 3.13, pdf 697

⁷⁵ EDMS 10329019, January 2016 Application, pdf 696.

⁷⁶ NSR Manual, p. B.45.

⁷⁷ NSR Manual at B.36; See also *Inter-Power of New York, Inc.*, 5 E.A.D. 130 at 136 (1994).

option, a permitting agency must determine that the cost-per-ton of emissions reduced is beyond “the cost borne by other sources of the same type in applying that control alternative.”⁷⁸ This high standard for eliminating a feasible BACT technology exists because the collateral impacts analysis in BACT step 4 is intended only as a safety valve for when impacts unique to the facility make application of a technology inapplicable to that specific facility. The LDEQ and the Applicant inappropriately argue the increase in capital cost of the facility is too high. To reject CCS, BACT requires a demonstration that the costs per ton of pollutant removed are disproportionately high for the specific facility compared to the cost per ton to control emissions at other facilities. No such comparison was made.

Although the BACT requirement to control GHG emissions in a PSD permit is relatively new, there are nevertheless many plants with similar emissions streams that currently use the Econamine process to capture CO₂ emissions. See Section I.B.5. However, the fact that the data are not presented in a BACT analysis does not mean they do not exist. The LDEQ must consider the cost of the Econamine process at these and other facilities when making a determination about whether the Econamine process plus compression and transport to an end use at the St. James Methanol Plant creates an adverse economic impact unique to the facility.

5. CCS Is Cost Effective

The BACT cost effectiveness analysis concluded that it would cost \$61.17/ton to remove and sequester 90% of the CO₂e emissions or 1,125,807 ton/yr from boiler and reformer offgases.⁷⁹ However, the record does not include any evidence that this value is not cost effective. A control technology is considered to be “cost effective” for BACT if its cost effectiveness in dollars per ton of pollutant removed falls within a reasonable range of cost-effectiveness estimates where other costs are calculated using the same methodology. The GHG Guidance notes that the “[t]o justify elimination of an option on economic grounds, the permit applicant should demonstrate that the cost of pollutant removal for that option are disproportionately high.”⁸⁰

\$61/ton is a very low cost effectiveness value that would be considered highly cost effective for any other pollutant or control technology. The typical range of acceptable cost effectiveness values for other pollutants is \$300 to \$28,672 per ton.⁸¹ There is no reason to

⁷⁸ NSR Manual at B.44; See also *Steel Dynamics, Inc.*, 9 E.A.D. 165 at 202 (2000); *Inter-Power*, 5 E.A.D. at 135 (“In essence, *if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and, therefore, acceptable as BACT.*” (quoting NSR Manual at B.44) (emphasis original)).

⁷⁹ EDMS 10329019, January 2016 Application, Table 3.13, pdf 697.

⁸⁰ GHG Guidance, pp. 38-39.

⁸¹ San Joaquin Valley Air Pollution Control District (SJVAPCD), Final Staff Report, Update to Rule to Rule 2201 Best Available Control Technology (BACT) Cost Effectiveness Thresholds, May 14, 2008; Available at: <https://www.valleyair.org/busind/pto/bact/May%202008%20BACT%20cost%20effectiveness%20threshold%20update%20staff%20report.pdf>; South Coast Air Quality Management District (SCAQMD), 2016 SCAQMD BACT

believe that acceptable cost effectiveness values for GHG would fall outside of this range. The reported cost effectiveness value of \$61/ton is highly cost effective.

The record here does not include any comparative cost effectiveness values for any pollutant, including CO₂e, for any control technology or process, even though the chosen carbon capture technology, which comprises the majority of the cost, an Econamine unit, has been used to recover CO₂ in hundreds of related applications and is being proposed as part of the Project itself to recover CO₂ from the reformer flue gases.

The Global CCS Institute has identified 38 large-scale CCS project around the world, either in operation, under construction or in various stages of planning,⁸² as shown in Figure 1. The record in this case does not identify a single one of them or summarize cost effectiveness information from them to evaluate the St. James Methanol Plant CCS system.

Figure 1: Key CCS Project Development and Milestones.⁸³



Hundreds of plants currently remove CO₂ from natural gas, hydrogen, and other gases with low oxygen content similar to the CO₂ laden gases here. The amine scrubbing and compression methods costed here to remove CO₂ from methanol plant gases have been used to separate CO₂ from natural gas and hydrogen since they were patented in 1930.⁸⁴ These

Cost Effectiveness Values, 2016; Available at:

<https://www.valleyair.org/busind/pto/bact/May%202008%20BACT%20cost%20effectiveness%20threshold%20update%20staff%20report.pdf>; Bay Area Air Quality Management District (BAAQMD), BACT/TBACT Workbook, Guidelines for Best Available Control Technology Including Best Available Control Technology for Toxics (TBACT). Ex. 2, Attachment C. See also summary of NO_x cost effectiveness values in Ex. 2, Attachment D that Dr. Fox prepared in another case.

⁸² Global CCS Institute, The Global Status of CCS, Summary Report, 2016, p. 7; Available at:

<http://hub.globalccsinstitute.com/sites/default/files/publications/201158/global-status-ccs-2016-summary-report.pdf>.

⁸³ Global CCS Institute, The Global Status of CCS; Available at: <http://status.globalccsinstitute.com/?v=2016>.

⁸⁴ Gary T. Rochelle, Amine Scrubbing for CO₂ Capture, *Science*, v. 325, no. 5948, 25 September 2009, pp. 1652-1654; Arthur L. Kohl and Richard B. Nielsen, *Gas Purification*, Gulf Publishing Co., Houston, 5th Ed., 1997, Chapter 2: Alkalnolamines for Hydrogen Sulfide and Carbon Dioxide Removal, pp. 40-186.

processes are used in many industries including: urea plants, ethanol plants, hydrogen plants, ammonia plants, ethylene oxide plants, natural CO₂ wells, geothermal wells, mineral processing plants, direct iron ore reduction plants, enhanced oil recovery, and methanol production.^{85, 86} The record here does not identify any unique circumstances that would render the Econamine process for CO₂ recovery at the St. James Methanol Plant not cost effective here, given its widespread use. The addition of compression and a pipeline to send the recovered CO₂ market would not affect the cost effectiveness conclusion as the CO₂ can be sold or would be eligible for a tax deduction. See Section IV.B.6.

The NSR Manual explains that “...if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT.”⁸⁷ Only “unusual circumstances may then be used to eliminate a control.”⁸⁸ The record in this case does not include any comparative cost-effectiveness data for any pollutant, including for CO₂e, violating a key requirement of the top-down BACT process. It also does not identify any “unusual circumstances” that would distinguish the use of an Econamine unit here to recover 90% of the remaining CO₂, after 65% of the Reformer vent stream is diverted to an Econamine unit to recover CO₂ for use in methanol production.⁸⁹

In sum, the estimated cost of \$61/ton does not necessarily constitute an adverse economic impact unless it is disproportionate to the cost-per-ton of CCS at other facilities. At a minimum, to reject CCS at St. James Methanol Plant when the facility itself is using the very process that constitutes over 90% of the cost of CCS, the Applicant must demonstrate—with actual data—that the cost per ton at St. James to remove additional CO₂ is disproportionate compared to other facilities already using the Econamine process and/or CCS (Figure 1). This demonstration is not in the record.

⁸⁵ See, for example, Witteman, By-Product CO₂ Recovery Systems, Industrial Gas Sources, Available at: http://www.pureco2nfidence.com/launch/images/downloads/wittemann_capabilities.pdf; Oatar Methanol Plant Due Carbon Dioxide Recovery Plant, Oil & Gas Journal, March 15, 2012, Available at: <http://www.ogj.com/articles/2012/03/qatar-methanol-plant-due-carbon-dioxide-recovery-plant.html>; Global CCS Institute, Projects, CO₂ Utilisation Plants Using the Fluor Econamine FG Process; Available at: <https://www.globalccsinstitute.com/projects/co2-utilisation-plants-using-fluor-econamine-fg-process>.

⁸⁶ See, for example, Rochelle 2009 and the QPC Quimica Methanol Plant for a specific recent example. This methanol plant, located in Brazil, has recovered CO₂ since 1997 using the Fluor Econamine FGSM process and supplied the captured gas to the food industry. Available at: <http://www.zeroco2.no/projects/metanol-plant-prosint> and Gulf Petrochemical Industries Company Carbon Dioxide Recovery Plant, Bahrain, Available at: <http://www.chemicals-technology.com/projects/gulfpetrochemicalsco/>.

⁸⁷ NSR Manual, p. B.44.

⁸⁸ *Id.*

⁸⁹ EDMS 10329019, January 2016 Application, pdf 671.

The LDEQ cannot simply reject a technologically feasible alternative to control GHGs because it did not find other BACT determinations requiring add-on technology to control GHG. There is no evidence in the record that LDEQ looked for comparative cost effectiveness data. Regardless, for every pollutant newly subject to a BACT limit and for every new technology developed to control that pollutant, there has to be a first instance where the control is determined to be BACT. The legislative history is clear that Congress intended BACT to perform a technology-forcing function.⁹⁰ The LDEQ has made no showing as to why the St. James Methanol Plant PSD permit should not require CCS, especially when other similar facilities employ CCS, even if not pursuant to a BACT determination. The BACT analysis of CCS must at a minimum consider costs at facilities that have deployed CCS to determine whether any unusual or unique circumstances at the St. James Methanol Plant warrants rejection of CCS.⁹¹

The GHG Guidance indicates “[t]here are compelling public health and welfare reasons for BACT to require all GHG reductions that are achievable...” because “...GHGs endanger both the public health and the public welfare of current and future generations. Among the public health impacts and risks that EPA cited are anticipated increases in ambient ozone and serious ozone-related health effects. Thus, the LDEQ should also consider the costs of failing to control GHG emissions, expressed as the social cost of carbon. There are several sources concluding that carbon has a high social cost. A recent study found that the social cost of carbon ranges from \$28 up to \$893 per ton of CO₂.⁹² EPA recently revised its estimated social cost of carbon to \$40 in 2015 and increasing up to \$76 by 2050.⁹³ These thresholds suggest that the cost of CCS at the St. James Methanol Plant, \$61/ton, would be a more economic choice compared to higher estimated social costs of carbon if these GHGs are not controlled.

In sum, if an Econoamine unit is cost effective to recover 722,700 ton/yr of CO₂ for use in the process, it is even more cost effective to recover 1,125,807 ton/yr as the per unit cost of equipment decreases as the size of the equipment increases. Thus, to eliminate removing additional amounts of CO₂ as BACT using this very same process requires that the record

⁹⁰ See S. Rep. No. 95-252, 95th Cong., 1st Sess. 31 (1977), reprinted in 3 A Legislative History of the CAA Amendments of 1977 at 1405; 123 Cong. Rec. S9171, 3 Legislative History at 729 (remarks of Sen. Edmund G. Muskie, principal author of 1977 Amendments).

⁹¹ See, e.g., *Cost and Performance of Carbon Dioxide Capture from Power Generation*, International Energy Agency. Available at: http://www.iea.org/publications/freepublications/publication/costperf_ccs_powergen-1.pdf

⁹² Ackerman, *Climate Risks and Carbon Prices: Revising the Social Cost of Carbon*, p. 2. Available at: http://www.sei-international.org/mediamanager/documents/Publications/Climate-mitigation-adaptation/Economics_of_climate_policy/sei-climate-risks-carbon-prices-2011-full.pdf.

⁹³ Assuming a 3% discount rate. Available here: <http://www.epa.gov/climatechange/EPAactivities/economics/scc.html>.

demonstrate unique circumstances.⁹⁴ The cost of compression and an 8-mi pipeline would be offset by selling the CO₂.

6. CCS Cost Are Unsupported and Overestimated

The GHG BACT cost effectiveness analysis is a one page table that presents lump sum costs with no support.⁹⁵ This is inadequate to support the estimated cost effectiveness value of \$61.17/ton. The NSR Manual indicates that “[t]he basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source such as the OAQPS Cost Control Manual...”⁹⁶ Supporting data is not present in the record.

The methodology set out in EPA’s Cost Control Manual⁹⁷ must be used to estimate cost effectiveness.⁹⁸ This methodology is specifically designed to allow comparison of cost effectiveness values across multiple units and facilities and locations to allow a level playing field. This methodology is a regulatory cost analysis that is not intended to reflect the real costs that will be associated with installing a control at a given facility. The regulatory cost is expressed in current real or constant dollars, less inflation. Consistency among analyses performed across the United States is critical to establish cost effectiveness. The Application did not use this method, rendering the resulting “cost effectiveness values” useless for rejecting controls based on cost. Some of the deviations that result in inflated costs, plus other errors and omissions as compared to valid cost effectiveness analyses, are discussed below.

First, a capital recovery factor or CRF is used to convert total capital cost into a stream of equal annual payments over a given time at a given interest rate. Under the Cost Manual methodology, total capital costs are annualized by calculating an annual payment sufficient to finance the investment over its entire life. This payment is calculated by multiplying the total capital investment by a capital recovery factor calculated from a formula based on interest rate and equipment lifetime.⁹⁹ The longer the service life and the lower the interest rate, the lower the annualized capital costs and the lower the cost effectiveness in \$/ton.

The GHG cost analysis assumed a 15-year equipment life and 8% interest rate. The lifetime used to calculate the capital recovery factor is the service life of the equipment. The lifetime is important because the shorter the lifetime, the higher the capital recovery factor and the higher the annual capital cost used to determine cost effectiveness. Absent a federally enforceable agreement requiring a date certain shutdown, the actual equipment lifetime should

⁹⁴ NSR Manual, p. B.29.

⁹⁵ EDMS 10329019, January 2016 Application, pdf 697.

⁹⁶ NSR Manual, p. B.33. See also p. B. 35 and Appendix B.

⁹⁷ U.S. EPA, EPA Air Pollution Control Cost Manual, Report EPA/452/B-02-001, 6th Ed., January 2002 (“Cost Manual”).

⁹⁸ NSR Manual, p. B.33 and Appendix B.

⁹⁹ Cost Manual, p. 2-21, pdf 35.

be used in BACT cost effectiveness analyses. The service lifetime of the equipment included in the CCS (e.g., pipeline, compressor, piping, etc.) is at least 30 years. The interest rate used to calculate the CRF is the “social” or “public” interest rate, which has been set at 7%, as recently confirmed by EPA.¹⁰⁰ Assuming a 30 year equipment life and 7% interest, the CRF used in the GHG cost analysis drops from 0.1168 to 0.0806,¹⁰¹ which reduces the cost effectiveness of CCS from \$61.17/ton to \$42.21/ton.

Second, the cost analysis includes owner’s costs, estimated as 11% of the purchased equipment cost or \$15,121,682. Owner’s costs are not allowed in cost effectiveness analyses.

Third, the cost analysis includes a “contingency & escalation” factor of 15% of purchased equipment cost, amounting to \$20,620,476. The Cost Manual approach explicitly excludes future escalation as cost comparisons are made on a current real dollar basis. Inflation is not included in cost effectiveness analyses as they rely on the most accurate information available at current prices and do not try to extrapolate those prices into the future.¹⁰² A contingency factor of 5% is more typical.

Fourth, the captured CO₂ would be exported via the Denbury Green Line.¹⁰³ CO₂ has a market value when used in enhanced oil recovery (EOR) or for other uses. The costs of carbon capture, for example, can be offset by EOR revenues where available.¹⁰⁴ Estimates of the market price of CO₂ for EOR are around \$33 per ton.¹⁰⁵ Even without EOR, CO₂ has a market value of between \$5-\$20 per ton.¹⁰⁶ CCS costs can be further offset by tax credits of \$10-\$20 per ton of CO₂ in accordance with Internal Revenue Code Section 45Q (26 USC § 45 Q). Neither the Application nor the Statement of Basis attempted to offset the cost of CCS with these potential revenue streams or tax credits. The ability of the Applicant to reduce its net cost of installing and operating CCS is a critical component of the cost effectiveness calculations.

The LDEQ must consider these issues in its BACT analysis to appropriately consider the cost of CCS as a control technology. The consideration of offsetting the cost of CCS is

¹⁰⁰ Cost Manual, Chapter 2. Selective Catalytic Reduction, May 2016, pdf 79, footnote 29; Available at: https://www3.epa.gov/ttn/ecas/docs/SCRCostManualchapter7thEdition_2016.pdf.

¹⁰¹ $CRF = (0.07 * (1.07^{30})) / (1.07^{30} - 1) = 0.0806$.

¹⁰² See, e.g., Cost Manual, p. 2-36, pdf 50.

¹⁰³ See EDMS 10329019, January 2016 Application, Table 3.13, “Pipeline to Denbury Green Line,” pdf 697.

¹⁰⁴ Massachusetts Institute of Technology, *Future of Coal in a Carbon Constrained World 2007* at 58-59, available at <http://web.mit.edu/coal/>.

¹⁰⁵ *Carbon Dioxide Enhanced Oil Recovery: A Critical Domestic Energy, Economic, And Environmental Opportunity*, National Enhanced Oil Recovery Initiative, Appendix D, Figure D1. Available at: http://www.neori.org/NEORI_Report.pdf.

¹⁰⁶ See, e.g., Rushing, Sam, *Carbon Dioxide Apps Are Key In Ethanol Project Developments*, Ethanol Producer Magazine, April 15, 2011. Available at: www.ethanolproducer.com/articles/7674/carbon-dioxide-apps-are-key-in-ethanol-project-developments.

especially critical because the LDEQ based its rejection of CCS on the cost impact of the technology in step 4 of the top-down BACT analysis.

The cost analysis failed to account for the relative advantages and market opportunities that the Applicant has to sell CO₂. The St. James Methanol Plant is only 8 miles from the Denbury Green Pipeline. The Preliminary Determination states that “[t]he Denbury Green Pipeline (CO₂ pipeline) extends across Louisiana from Donaldsonville westward towards Lake Charles and ends in Hastings Field south of Houston, Texas. As the CO₂ would be captured and transported to the Denbury pipeline, it could then be sold for use in enhanced oil recovery projects.”¹⁰⁷ Denbury Resources uses CO₂ in enhanced oil recovery,¹⁰⁸ but the BACT cost effectiveness analysis does not include any information on the potential market value that Denbury Resources would offer for the purchase of the captured CO₂. The analysis also does not consider other potential markets for the sale of CO₂ for other industrial applications. Any potential sale value of CO₂ would offset the cost of CCS and should be included in the cost effectiveness analysis. Finally, as noted above, the Applicant did not include any analysis of tax savings or credits that could be realized under Internal Revenue Code Section 45Q.

In sum, just correcting the lifetime and interest rate and assuming the CO₂ is sold for \$20/ton or receives an equivalent tax deduction, the cost effectiveness of CCS drops from \$61/ton to \$22/ton. Correcting other errors and omissions in the CCS cost analysis would further decrease the cost effectiveness of CCS. Carbon capture and control at the St. James Methanol Plant is thus highly cost effective when properly analyzed.

C. BACT for VOC and CO Emissions from Boilers 1 and 2

The project includes two 350 MMBtu/hr natural-gas-fired boilers (B1-13, B2-13) to provide steam for both the methanol synthesis reaction and the Econamine unit. The January 2016 Application includes a top-down BACT analysis for CO and VOCs.¹⁰⁹

The BACT analyses for the boilers evaluated two methods to reduce CO and VOC emissions, an oxidation catalyst and good combustion practices and three methods to reduce VOCs, an oxidation catalyst, good combustion practices and EMx/SCONOx.¹¹⁰ The analysis concluded that BACT for CO from these boilers is 0.038 lb/MMBtu and 13.30 lb/hr, using good combustion practices. The BACT analysis for VOC concluded that BACT for VOCs is 0.00539

¹⁰⁷ EDMS 10329019, Preliminary Determination Summary, pdf 82 and January 2016 Application, pdf 226-227.

¹⁰⁸ Denbury, Operations, December 23, 2016, See CO₂ Captured from Industrial Sources (“In addition to the potential CO₂ sources discussed above, we continue to have ongoing discussion with owners of existing plants of various types that emit CO₂ that we may be able to purchase and/or transport... We believe that we are a likely purchaser of CO₂ captured in our areas of operation because of the scale of our tertiary operations and our CO₂ pipeline structure”, which is only 8 miles from the St. James site; Available at: <http://www.denbury.com/operations/gulf-coast-region/co2-sources-and-pipelines/default.aspx>.

¹⁰⁹ EDMS10329019, January 2016 Application, Sections 3.2.8 and 3.2.9, pp. 51- 57, pdf 704-710.

¹¹⁰ EDMS10329019, January 2016 Application, Table 3.19, pdf 705 (CO) and Table 3.22, pdf 708 (VOC).

lb/MMBtu and 1.89 lb/hr, using good combustion practices.¹¹¹ Catalytic oxidation was eliminated in both cases as BACT due to a catalyst waste stream and elevated cost effectiveness values of \$45,010/ton per boiler for CO¹¹² and \$79,095/ton per boiler for VOCs.¹¹³

The top-down guidance in the NSR Manual sets out a very strict standard that must be met when the top limit is not picked, as here, *viz.*, “In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding needs to be fully documented for the public record.”¹¹⁴ However, the stated reasons for eliminating catalytic oxidation, adverse environmental and economic impacts, are misinformed, incorrect, and unsupported.

Oxidation catalysts are used on hundreds of similar boilers and other fired sources, such as heaters and gas turbines, to remove up to 99%+ of the CO and up to 90% of VOC.¹¹⁵ This is reflected in air pollution control agency BACT guidelines. The Bay Area Air Quality Management District’s (BAAQMD’s) BACT guidelines for boilers with a firing rate greater than 50 MMBtu/hr, for example, identifies “technologically feasible/cost effective BACT” as a CO limit of 10 ppmv @ 3% O₂ dry (equal to about 0.0074 lb/MMBtu, based on the use of an oxidation catalyst).¹¹⁶

Further, the St. James Methanol Plant record identifies similar boilers with lower BACT emission limits than required here. The RBLC is an incomplete summary of BACT determinations as reporting is not mandatory. See IV, RBLC discussion.

The January 2016 Application’s summary of RBLC BACT determinations for CO emissions from similar fired sources identifies two boilers that selected an oxidation catalyst as BACT for CO emissions. These included a 456 MMBtu boiler that was permitted with a CO emission rate of 0.0013 lb/MMBtu, achieved using an oxidation catalyst and a 60.1 MMBtu/hr boiler permitted with a CO emission rate of 0.0164 lb/MMBtu,¹¹⁷ compared to a CO BACT limit for the St. James Methanol Plant of 0.038 lb/MMBtu. The Kalama Application’s¹¹⁸ summary of

¹¹¹ EDMS10329019, Specific Conditions, pdf 121.

¹¹² EDMS10329019, January 2016 Application, Table 3.21, pdf 707.

¹¹³ EDMS10329019, January 2016 Application, pdf 705 and Table 3.23, pdf 688, 710.

¹¹⁴ NSR Manual, pp. B.26, B.29.

¹¹⁵ See, e.g., BASF, Oxidation Catalyst for the Power Generation Industry, January 14, 2014; Available at: http://www.ccj-online.com/wp-content/uploads/gravity_forms/3-b246f63cf9a9ff5af247a3db291cb13f/2014/02/Oxidation-Catalysts-datasheet-BF-8358-Updated-01.14.14.pdf.

¹¹⁶ BAAQMD, Best Available Control Technology (BACT) Guideline, > 50 MMBtu/hr Heater Input Boiler, August 4, 2010; Available at: <http://www.baaqmd.gov/~media/files/engineering/bact-tbact-workshop/combustion/17-3-1.pdf?la=en>.

¹¹⁷ EDMS10329019, January 2016 Application, Appendix D, Permit IA-0106, pdf 924.

¹¹⁸ Ramboll Environ US Corporation, Prevention of Significant Deterioration and Air Discharge Permit Application, Kalama Manufacturing and Marine Export Facility, Prepared for Northwest Innovation Works, Kalama, LLC, Kalama, Washington, February 2016; Available at: http://www.ecy.wa.gov/programs/air/psd/PSD_PDFS/Kalama_PSD_app.pdf.

RBLC BACT determinations for CO emissions from similar boilers identifies a 435 MMBtu/hr boiler with a CO BACT determination of 0.009 lb/MMBtu achieved with an oxidation catalyst.¹¹⁹

The Application's RBLC BACT summary for VOC emissions identifies five similar sources for which BACT was determined to be an oxidation catalyst that achieved lower VOC emission rates than proposed here as BACT.¹²⁰ Finally, the Kalama Methanol Facility is proposing to use catalytic oxidation and good combustion practices to achieve an outlet CO concentration of 5 ppm, equivalent to about 0.0037 lb/MMBtu,¹²¹ or a factor of ten lower than proposed as BACT at the St. James Methanol Plant.

The St. James Methanol Plant record is silent on why these lower VOC and CO BACT limits based on catalytic oxidation for similar boilers do not establish BACT for the St. James Methanol Plant boilers. BACT for CO and VOC emissions from both boilers is an oxidation catalyst designed to remove 99% of the CO and 90% of the VOCs.

1. The CO and VOC BACT Analyses for the Boilers Improperly Eliminated an Oxidation Catalyst Based on Adverse Energy and Environmental Impacts

The CO and VOC BACT analyses eliminate catalytic oxidation due to energy and environmental impacts. The CO BACT analysis states “[t]here are also associated environmental and energy impacts with this technology. The catalyst creates a new waste stream that requires periodic treatment and disposal.”¹²² The VOC BACT analysis makes a similar argument: “There are also associated environmental and energy impacts with this technology. The catalyst creates a new waste stream that requires periodic treatment and disposal. The addition of a post-combustion catalyst unit and an increase electrical demand on the draft fans to combat a pressure drop through the system catalyst bed will result in higher energy costs for the facility. Therefore, catalytic oxidation was rejected as a BACT option.”¹²³

However, all oxidation catalyst systems create a catalyst waste stream and increase electrical demand. There is no demonstration in the record that either would result in an adverse impact or create an impact for the St. James Methanol Plant that is greater than experienced by other facilities that use catalytic oxidation. The NSR Manual explains that “...the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BACT, particularly if the control device has been applied

¹¹⁹ Kalama Application, Ex. 2, Attachment A, pdf 214 (MD-0044).

¹²⁰ EDMS10329019, January 2016 Application, Appendix D, Permits CT-0156 (5.5 lb/hr); MN-0054 (7.1 ppm & 3.4 ppm); OR-0046 (0.0044 lb/MMBtu), PA-0253 (0.46 lb/hr), pdf 915-918.

¹²¹ Kalama Application, Section 2.4.3, p. 18, pdf 162.

¹²² EDMS 10329019, January 2016 Application, Section 3.2.8.2, pdf 705.

¹²³ EDMS 10329019, January 2016 Application, Section 3.2.9.2, pdf 709.

to similar facilities elsewhere and the solid or liquid waste problem under review is similar to those other applications.”¹²⁴

For a technology such as catalytic oxidation that has been applied to similar facilities elsewhere, the applicant must demonstrate unusual circumstances at the proposed facility that create greater problems than experienced elsewhere.¹²⁵ There is no demonstration of unique circumstances in the record and, indeed, none exist. Further, oxidation systems do not create a waste stream that is disposed at the site. Rather, used catalyst is returned to the vendor for recycling. Oxidation catalysts contain significant amounts of platinum that can be recovered.

2. The CO and VOC BACT Analysis for the Boilers Improperly Eliminated an Oxidation Catalyst Based on Adverse Economic Impacts

The CO BACT analysis rejects catalytic oxidation to control CO as it would cost \$45,010/ton.¹²⁶ The VOC BACT analysis rejects catalytic oxidation to control VOC as it would cost \$79,095/ton.¹²⁷

The record does not include any evidence that these values are not cost effective. In fact, the record does not contain any comparative cost effectiveness data for any source or pollutant and is thus fundamentally flawed. A control technology is considered to be “cost effective” for BACT if its cost effectiveness in dollars per ton of pollutant removed falls within the range of cost-effectiveness estimates for other facilities using the same methodology. The record does not contain any cost effectiveness values for other similar fired sources where oxidation catalysts are currently used or proposed to be used.

Further, the EPA has concluded that “where controls have been effectively employed in the same source category, the economic impact of such controls on the particular source under review should not be nearly as pertinent to the BACT decision making process. Thus, where controls have been successfully applied to similar sources in a category [which is the case here], an applicant should concentrate on documenting significant cost differences, if any, between the application of the controls on those sources and the particular source under review.”¹²⁸

The NSR Manual explains that “...if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially

¹²⁴ NSR Manual, p. B.47.

¹²⁵ NSR Manual, p. B.47 (The applicant and LDEQ must demonstrate “unusual circumstances at the proposed facility to create greater problems than experienced elsewhere...”).

¹²⁶ EDMS 10329019, January 2016 Application, Section 3.2.8.2, pdf 705.

¹²⁷ EDMS 10329019, January 2016 Application, Section 3.2.9.2, pdf 709.

¹²⁸ Letter from Robert B. Miller, Chief, Permits and Grants Section, U.S. EPA, to Lynn Fiedler, Michigan Department of Environmental Quality, October 6, 1999; Available at: <https://www.epa.gov/sites/production/files/2015-07/documents/cadillac.pdf>.

be considered economically achievable, and therefore acceptable as BACT.”¹²⁹ Only “unusual circumstances may then be used to eliminate a control.”¹³⁰ The record in this case does not include any comparative cost-effectiveness data for any pollutant, violating a key requirement of the top-down BACT process. It also does not identify any “unusual circumstances” that would distinguish the use of an oxidation catalyst here with the hundreds of other combustion sources that currently use this technology.

3. Oxidation Catalyst Costs Are Unsupported and Overestimated

As explained in Section IV.B.6, the costing methodology used for BACT cost effectiveness analyses as presented in the Control Cost Manual is specifically designed to allow comparison of cost effectiveness values across multiple units and facilities and locations. The Application did not use this method, rendering the resulting “cost effectiveness values” useless for rejecting controls based on cost. Some of the deviations that result in inflated costs are discussed below.

The cost effectiveness values for VOC and CO are significantly overestimated, as discussed below, in large part due to the failure to follow proper BACT costing methodology. The Boiler CO and VOC BACT cost effectiveness analyses are one page tables that present unsupported lump sum costs.¹³¹ This is inadequate to support the estimated cost effectiveness value of \$45,010/ton for CO and \$79,095/ton for VOC, which are significantly outside of the range of numerous similar CO BACT cost effectiveness analyses that I have reviewed and/or prepared due to improper methodology. The NSR Manual indicates that “[t]he basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source [such as the OAQPS Cost Control Manual...].”¹³² Supporting data is not present in the record. Some of the errors and omissions are discussed below.

First, as explained in Section IV.B.6, the CRF used to annualize capital costs assumed a 15-year equipment life and 8% interest rate, which are inconsistent with the Cost Control Manual. The service lifetime of an oxidation catalyst system [metal support structure as the catalyst is changed out periodically] is at least 30 years. The interest rate used to calculate the CRF should be 7%. Assuming a 30 year equipment life and 7% interest, the CRF used in the CO and VOC cost analysis drops from 0.1168 to 0.0806,¹³³ which reduces the cost effectiveness by 31%.

¹²⁹ NSR Manual, p. B.44.

¹³⁰ *Id.*

¹³¹ EDMS 10329019, January 2016 Application, Table 3.21, pdf 707 (CO) and Table 3.24, pdf 710 (VOC).

¹³² NSR Manual, p. B.33.

¹³³ $CRF = (0.07 * (1.07^{30})) / (1.07^{30} - 1) = 0.0806$.

Second, the cost analysis includes owner's costs, estimated as 11% of the purchased equipment cost. Owner's costs are not allowed in BACT cost effectiveness analyses.

Third, the cost analysis includes a "contingency & escalation" factor of 15% of purchased equipment cost. The Cost Manual approach explicitly excludes future escalation as cost comparisons are made on a current real dollar basis. Inflation is not included in cost effectiveness analyses as they rely on the most accurate information available at current prices and do not try to extrapolate those prices into the future.¹³⁴ A contingency factor of 5% is more typical.

Fourth, U.S. EPA guidance states that when a control option controls multiple pollutants the costs are to be apportioned to each pollutant before the dollars per ton is figured for cost-effectiveness.¹³⁵ Responding to a question by Georgia permitting authorities on how to account for a control device that reduces both VOC and CO, U.S. EPA agreed with the Georgia agency's interpretation that the cost-effectiveness should be calculated by "dividing the annualized cost of the control device by the total of the CO and VOC emissions reduced by said device." *Id.* Thus, in this case, the cost of an oxidation catalyst, which simultaneously reduces CO and VOC, must be divided by the total reduction of all pollutants reduced, *i.e.*, the sum of CO and VOC.

Fifth, the Project includes two identical 350 MMBtu/hr boilers. The purchased equipment cost, the starting point for the cost analysis, is based on a single boiler. There are many economies involved in designing, procuring, and installing two boilers from the same vendor. Only one system must be designed, which could be replicated for the other, reducing engineering and shop setup time. Thus, vendors typically offer discounts for awards of multiples of the same system. There is no evidence that multiple unit discounts were factored into the cost analysis. Considerable savings could be achieved in capital costs and labor by designing and constructing both boilers at once.

Sixth, direct and indirect capital costs were estimated by multiplying purchased equipment cost by factors. The factors used in the St. James Methanol Plant cost analysis are significantly higher than those recommended in the Cost Control Manual, thus inflating total installed costs.

Seventh, the cost analyses included the cost oxidation catalyst as a lump sum in the operating costs. Because catalyst lasts for more than a year but are consumed by the system, they cannot be included in maintenance and operations costs, which are annual costs. Instead,

¹³⁴ See, e.g., Cost Manual, p. 2-36, pdf 50.

¹³⁵ Letter from Brian L. Beals, Chief Preconstruction/HAP Section, U.S. EPA Air and Radiation Technology Branch, to Edward Cutrer, Jr., Program Manager, Georgia Department of Natural Resources, March 24, 1997 (Responding to a question by Georgia permitting authorities of how to account for a control device that reduces both VOC and CO, EPA agreed with the Georgia agency's interpretation that the cost-effectiveness should be calculated by "dividing the annualized cost of the control device by the total of the CO and VOC emissions reduced by said device.") ; Available at: <https://www.epa.gov/sites/production/files/2015-07/documents/gacost.pdf>.

they must be annualized.¹³⁶ The VOC and CO cost analyses included catalyst cost and installation labor as a lump sum under operating cost, thus significantly overestimating them.

Finally, a recent oxidation catalyst cost analysis for a similar boiler at the Kalama Methanol Facility estimated a cost effectiveness of \$7,512/ton.¹³⁷ This cost analysis also contains numerous errors and omissions, thus overestimating costs. However, it demonstrates the significant overestimate for the St. James Methanol Plant boilers.

In sum, the cost effectiveness of catalytic oxidation to control CO and VOC is significantly overestimated. Dr. Fox's opinion, based on her work in many similar cases, is that the cost effectiveness is less than \$5,000/ton to control both CO and VOCs. Ex. 2 at 31. Absent an on-the-record demonstration of unique circumstances at St. James Methanol Plant, catalytic oxidation must be used to control CO and VOCs at the St. James Methanol Plant.

D. BACT for PM/PM10/PM2.5 Emissions from the Econamine Cooling Tower (ECT-14)

The Project includes two cooling towers, an 18 cell, 230,000 gal/min wet evaporative cooling tower to provide cooling for circulating water used in the reforming process and a three cell, 29,120 gal/min cooling tower used to provide cooling for the Econamine unit to prevent thermal degradation of the EFG+ solvent.¹³⁸ The BACT analysis for these cooling towers did not follow the five-step top down process. Rather, it simply asserts, without any support, that "SJMP will install high efficiency drift eliminators with a maximum drift rate of 0.0005% for CT-13 and 0.001% for ECT-14 as BACT."¹³⁹

The BACT analysis does not justify a higher drift rate of 0.001% for the Econamine cooling tower, which would allow twice as much particulate matter emissions as a 0.0005% drift rate. Further, the BACT analysis did not consider other options to control PM/PM10/PM2.5 emissions from the cooling towers, including dry cooling and limiting the TDS of the circulating water.¹⁴⁰ The assumed TDS of the circulating water is high, 4,550 ppm,¹⁴¹ and does not represent BACT. Much lower TDS levels are feasible in the circulating water. Further, the proposed permit fails to establish any limit on the TDS of the circulating water.¹⁴²

Appendix D of the January 2016 Application contains RBLC Clearinghouse BACT/LAER determinations for particulate matter emissions from cooling towers. The cooling

¹³⁶ Cost Manual, p. 2-33.

¹³⁷ Kalama Application, Table B-1.

¹³⁸ EDMS10329019, January 2016 Application, pdf 715, 716, 815, 816.

¹³⁹ EDMS10329019, January 2016 Application, Section 3.4.1, pdf 716.

¹⁴⁰ See, for example, the BACT analysis for the Kalama cooling tower in the Kalama Application, Section 5, pp. 37-40.

¹⁴¹ EDMS10329019, January 2016 Application, pdf 434, 435.

¹⁴² EDMS10329019, January 2016 Application, pdf 46-47, 53.

tower summary table includes 40 particulate matter BACT determinations expressed as drift rates, of which 15 or 38% are 0.0005%. The final step in the BACT process is to select the most effective control option remaining after Step 4, in which collateral economic, environmental and energy impacts of the various control technologies are evaluated. The Application did not identify any adverse collateral impacts of using a 0.0005% efficient drift eliminator for the Econamine cooling tower, and I am not aware of any.

Further, the currently proposed Kalama Methanol Plant in Washington concluded BACT for its mechanical draft cooling tower is a drift eliminator design guaranteed to limit drift to a maximum of 0.0005% coupled with a TDS limit of 1,250 ppm.¹⁴³ As BACT must represent the “maximum degree of reduction... that is achievable” after “taking into account energy, environmental, and economic impacts and other costs,” BACT for PM/PM10/PM2.5 emissions from the Econamine cooling tower is a drift eliminator with a 0.0005% rate. Consideration should also be given to lowering the circulating water TDS for both cooling towers.

E. BACT for VOC Emissions from the Methanol Product Tanks

The Project includes two above ground storage tanks to store methanol product prior to being sent by pipeline to a storage terminal for shipment. The Application concluded that BACT for VOC emissions from these tanks is the use of internal floating roof tanks with an inert gas blanket.¹⁴⁴ However, as discussed below, the BACT analysis failed to evaluate the most effective control technology and falsely implies inert gas blanketing controls VOC emissions.

The BACT analysis for the methanol product tanks evaluated four control technologies: (1) internal floating roof tank with inert gas blanketing; (2) external floating roof tank; (3) fixed roof tank with vapor capture and thermal oxidizer; and (4) fixed roof tank with vapor capture and wet scrubber.¹⁴⁵

The BACT analysis selected internal floating roof tanks with inert gas blanketing as BACT for VOC emissions. However, as discussed below, this is not the top technology. The BACT analysis failed to include the most effective VOC control technology for these tanks, which is a welded cable-suspended internal floating roof tank with a geodesic dome. Blanketing could be used with this tank design, but is generally not required to control VOC emissions, unless matched with a process to recover the VOCs from the inert gas before it is released to atmosphere.

Methanol is very flammable, with an upper flammability limit of 36% by volume. Methanol vapors will exist at high concentrations in the vapor space between the fixed and floating roofs. These vapors can ignite and burn inside the tank vapor space and create a fire hazard near the tanks if an ignition source is present. Fire risk at methanol tanks is typically

¹⁴³ Kalama Application, Section 5.5, p. 40, pdf 185.

¹⁴⁴ EDMS 10329019, January 2016 Application, pdf 719-722.

¹⁴⁵ EDMS 10329019, January 2016 Application, Table 3.28, pdf 720.

controlled using inert gas blanketing or by eliminating ignition sources in the vicinity of the tank.¹⁴⁶

In blanketing, the air space within the tank is filled with an inert gas, generally nitrogen. As the tank fills with methanol, it displaces the nitrogen to atmosphere and as the tank empties, more nitrogen is added, to maintain an inert atmosphere.¹⁴⁷ However, to control VOC emissions, the flushed vapors must then be collected in a system that will allow them to be thermally oxidized, controlled with a carbon column, or possibly recovered for reuse. If liquid nitrogen is used, the vapors can be condensed and the VOCs recovered.

However, VOC recovery from the inerting gas is not proposed. The record is silent on the details of the proposed inerting, including the material (nitrogen?), the amount that would be used, and the disposition of the inert gas after it is discharged from the tank, pregnant with VOCs.

Generally, the goal of inerting is to prevent contact of the product with oxygen and combustion of headspace vapors during storage, not to control VOC emissions. Blanketing reduces the oxygen content in the vapor space of the tank, making it inert. It also eliminates the possibility of fire or explosion, decreases evaporation (and hence VOC emissions), protects the tank from structural corrosion damage caused by air and moisture, and protects the product from degradation.¹⁴⁸

Inerting is not used to control VOC emissions. In fact, depending on the design of the inerting system, which is not disclosed in the record, inerting can also strip vapors from the headspace, increasing VOC emissions. A continuous purge system, for example, uses a constant flow of nitrogen and is easy to implement. However, they can strip vapors from the headspace, which can increase VOCs.^{149,150}

¹⁴⁶ Methanol Institute, Methanol Safe Handling Technical Bulletin, Atmospheric Above Ground Tank Storage of Methanol; Available at: <http://www.methanol.org/wp-content/uploads/2016/06/AtmosphericAboveGroundTankStorageMethanol-1.pdf>.

¹⁴⁷ See, e.g., Jessica Ebert, Playing It Safe with Methanol, Biodiesel Magazine, June 21, 2007; Available at: <http://biodieselmagazine.com/articles/1709/playing-it-safe-with-methanol/>.

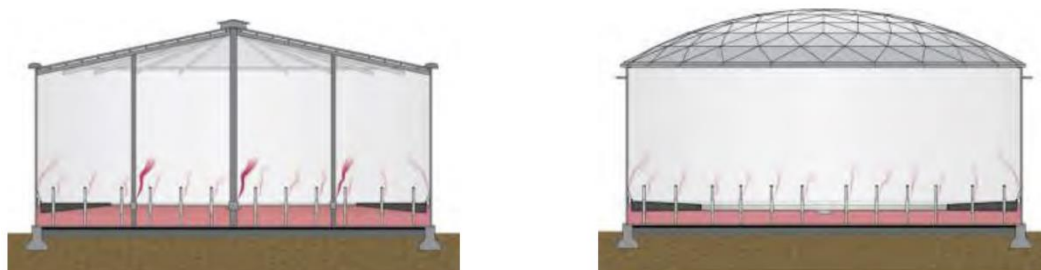
¹⁴⁸ Sage, Nitrogen Blanketing for Storage Tanks and Vessels; Available at: <https://sagemetering.com/applications/technical-notes/nitrogen-blanketing-for-storage-tanks-and-vessels/>. See also: Methanol Safe Handling Bulletin; Available at: <http://webcache.googleusercontent.com/search?q=cache:AdpgbqF1ukYJ:www.impca.eu/media/d9c3dd75-7f9c-4942-a894-7e41da4a9659/qS0aLg/Documents/M%2520I%2520Documents/Nitrogen%2520Blanketing%2520for%2520Storage%2520and%2520Transportation.pdf+&cd=13&hl=en&ct=clnk&gl=us>.

¹⁴⁹ Paul Yanisko, Bill Carlson, and Dan Ray, Best Practices in Nitrogen Blanketing for Storage Tanks and Vessels, December 12, 2012; Available at: <https://www.youtube.com/watch?v=i4iHpl6VXWk>.

¹⁵⁰ P. Yanisko et al., Nitrogen: A Security Blanket for the Chemical Industry, Chemical Engineering Progress, November 2011, pdf 3; Available at: <http://www.airproducts.cz/~media/downloads/article/N/en-nitrogen-blanketing-article.pdf>.

Regardless of the details of the inerting method, traditional internal floating roof tanks with column-supported cone roof tanks, as proposed here,¹⁵¹ have substantially higher VOC standing losses than self-supported geodesic domed internal floating roof tanks due to the penetrations in the floating roof for the legs supporting the cone roof which allow vapors to escape into the air space above (vapor emissions indicated in red in Figure 2). As explained below, BACT for the methanol product tanks is a welded cable-suspended internal floating roof tank with a geodesic dome. If required for safety and product integrity, an inert gas blanket can be used if VOCs trapped in the inerting gas are not emitted.

Figure 2: Internal floating roof tanks with column-supported cone roof (left) and self-supporting geodesic dome (right)¹⁵²



For example, a 120-foot diameter tank located in Houston, a similar climate to St. James, storing gasoline with an RVP of 10 and 24 cycles per year is estimated to emit 2,986 lbs./year less VOC if equipped with a self-supported geodesic roof compared to a column-supported cone roof.¹⁵³

The EPA concluded, in a recent NOV issued to a rail terminal that geodesic domes are BACT for internal floating roof tanks as this control technology has been achieved in practice:

Geodesic domes have been installed in the United States which enclose tanks storing petroleum liquids. These domes lower emissions from the tanks. Since this control technology has been achieved in practice, it is BACT for this type of tanks.¹⁵⁴

¹⁵¹ See TANKS 4.09 runs at EDMS 10329019, January 2016 Application, pdf 829-840.

¹⁵² Excerpted from: Eickhoff, HMT Inc., Reducing Storage Tank Emissions without Compromising Operational Performance, modified September 9, 2013; available at: <https://www.nistm.org/PDF/Morning/Eickhoff.pdf>.

¹⁵³ Eickhoff, *op. cit.*

¹⁵⁴ *In the Matter of Yuhuang Chemical Inc.*, Order on Petition No. VI-2015-03, Aug. 31, 2016, (Yuhuang Order) Available at: https://www.epa.gov/sites/production/files/2016-09/documents/yuhuang_response2015_0.pdf, Paragraph 31.

As of a decade ago, over 10,000 aluminum domes had been installed on storage tanks,¹⁵⁵ including on methanol storage tanks.¹⁵⁶ The ExxonMobil Torrance Refinery “completed the process of covering all floating roof tanks with geodesic domes to reduce volatile organic compound (VOCs) emissions from facility storage tanks in 2008. By installing domes on our storage tanks, we’ve reduced our VOC emissions from these tanks by 80%. These domes... help reduce VOC emissions by blocking much of the wind that constantly flows across the tank roofs, thus decreasing evaporation from these tanks.”¹⁵⁷

A crude storage project, recently proposed at the Phillips 66 Los Angeles Carson Refinery, required external floating roof tanks with geodesic domes to store crude oil with an RVP of 11.¹⁵⁸ The South Coast Air Quality Management District (“SCAQMD”) required the ConocoPhillips Wilmington Refinery to add a geodesic dome to an existing oil storage tank to satisfy BACT.¹⁵⁹ Similarly, Chevron proposed to use domes on several existing tanks to mitigate VOC emission increases at its Richmond Refinery.¹⁶⁰ Further, the U.S. Department of Justice (“DOJ”) and EPA Consent Decree for CITGO Petroleum Corporation required a geodesic dome on a gasoline storage tank at the company’s Lamont, Texas refinery.¹⁶¹ Finally, numerous vendors have provided geodesic domes for tanks.¹⁶²

¹⁵⁵ M. Doxey and M. Trinidad, Geodesic Dome Roof for Both New and Tank Retrofit Projects, Materials Forum, v. 30, 2006 (Ex. 2, Attachment E).

¹⁵⁶ See, e.g., Full Contact Internal Floating Roofs and Dome Roofs for Methanol Storage Tanks – CTS Latin (n 2007 CTS was contracted to supply 3 aluminum domes and 3 direct contact internal floating roofs for 3 new Methanol tanks under construction at the Odfjell Terminal Rotterdam (OTR).); Available at: http://pinnaclegroup.info/crusher/11993-floating-tank-roofs*#.

¹⁵⁷ ExxonMobil, Torrance Refinery: An Overview of our Environmental and Social Programs, 2010; Available at: http://www.exxonmobil.com.sg/NA-English/Files/About_Where_Ref_TorranceReport.pdf.

¹⁵⁸ See, e.g., Final Negative Declaration, Phillips 66 Los Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project, December 2014, Table 1-1 and p. 1-1; Available at: <http://www.aqmd.gov/docs/default-source/ceqa/documents/permit-projects/2014/phillips-66-fnd.pdf?sfvrsn=2>. (“The proposed project would comply with the South Coast Air Quality Management District’s (SCAQMD) best available control technology (BACT) requirements, as applicable, for control of volatile organic compounds (VOCs) emissions from refinery storage tanks.”)

¹⁵⁹ SCAQMD, Letter to G. Rios, EPA, Re: Proposed Minor Revision to Title V Facility Permit, ConocoPhillips – Wilmington Refinery, December 4, 2009; Available at: [http://yosemite.epa.gov/r9/air/epss.nsf/e0c49a10c792e06f8825657e007654a3/e97e6a905737c9bd882576cd0064b56a/\\$FILE/ATTTOA6X.pdf/ID%20800363%20ConocoPhillips%20Wilmington%20-%20EPA%20Cover%20Letter%20-%20AN%20501727%20501735%20457557.pdf](http://yosemite.epa.gov/r9/air/epss.nsf/e0c49a10c792e06f8825657e007654a3/e97e6a905737c9bd882576cd0064b56a/$FILE/ATTTOA6X.pdf/ID%20800363%20ConocoPhillips%20Wilmington%20-%20EPA%20Cover%20Letter%20-%20AN%20501727%20501735%20457557.pdf).

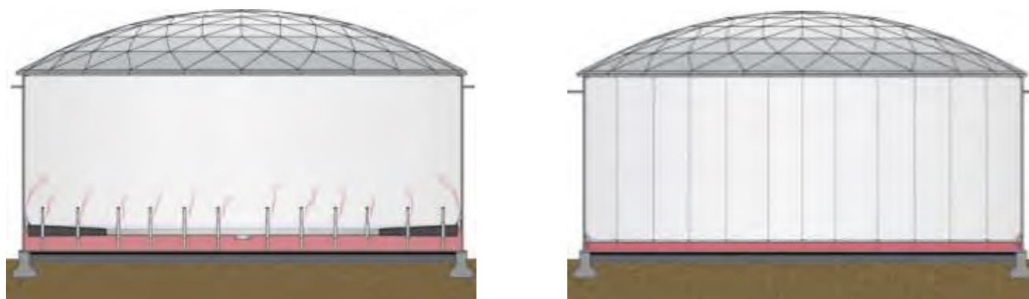
¹⁶⁰ City of Richmond, Chevron Refinery Modernization Project, Draft Environmental Impact Report, Volume 1: March 2014, Chapter 4.3; Available at: <http://chevronmodernization.com/project-documents/>.

¹⁶¹ DOJ and EPA, CITGO Petroleum Corporation Clean Air Act Settlement, September 19, 2013; Available at: <http://www2.epa.gov/enforcement/citgo-petroleum-corporation-clean-air-act-settlement>.

¹⁶² See, e.g., Tank Aluminum Cover, Aluminum Geodesic Dome; Available at: <http://tankaluminumcover.com/Aluminum-Geodesic-Dome>; Larco Storage Tank Equipment, Aluminum Domes; Available at: http://www.larco.fr/aluminum_domes.html; Vacono Dome; Available at: http://www.easyfairs.com/uploads/tx_ef/VACONODOME_2014.pdf; United Industries Group, Inc., Geodesic Aluminum Dome Roofs; Available at: <http://www.unitedind.com/products/aluminum-domes-and-floating-roofs/>.

Emissions from internal floating roof tanks with geodesic domes can be further reduced by eliminating the leg-supports and instead suspending the internal floating roof with cables, as shown in Figure 3.

Figure 3: Leg-supported internal floating roof (left) and suspended internal floating roof (right)¹⁶³



Cable-suspended internal floating roofs have full contact with the liquid below and eliminate both the emissions from legs openings and those associated with the pontoons. For example, a 120-foot diameter tank in Houston storing gasoline with an RVP of 10 and 24 cycles per year is estimated to emit 2,940 lbs./year of VOC fewer if equipped with a cable-suspended internal roof compared to a leg-supported internal roof.¹⁶⁴ Cable-suspended internal floating roofs are made from aluminum or composite as steel is too heavy for suspending. These tanks are offered by many manufacturers as state-of-the-art.¹⁶⁵ Tesoro installed cable-suspended, full-contact floating roofs at several tanks at its Wilmington Refinery.¹⁶⁶

Cable-suspended full-contact floating roof tanks (with drain-dry tank bottom and a vapor control device) are also identified as BACT for gasoline storage tanks by the Massachusetts Department of Environmental Protection (“MassDep”).¹⁶⁷

In sum, BACT for the methanol product tanks is a welded cable-suspended internal floating roof tank with a geodesic dome. If the tanks are inerted for safety reasons, the released inset gas must be captured and controlled.

¹⁶³ Eickhoff, *op. cit.*

¹⁶⁴ Eickhoff, *op. cit.*

¹⁶⁵ For example, AllenTech; <https://www.allentech.com/products/internal-floating-roofs/cable-suspension/>.

¹⁶⁶ SCAQMD, Tesoro Refining and Marketing Co., Wilmington, CA, Facility ID # 8003436, Application No. 518304, February 19, 2011; available at: [https://yosemite.epa.gov/r9/air/epss.nsf/6924c72e5ea10d5e882561b100685e04/180cbf8cc7d1308c8825798a0063d628/\\$FILE/ID%20800436%20Tesoro%20Refining%20Marketing%20Co%20-%20Engr%20Eval%20AN%20518304](https://yosemite.epa.gov/r9/air/epss.nsf/6924c72e5ea10d5e882561b100685e04/180cbf8cc7d1308c8825798a0063d628/$FILE/ID%20800436%20Tesoro%20Refining%20Marketing%20Co%20-%20Engr%20Eval%20AN%20518304).

¹⁶⁷ MassDEP, Top Case Best Available Control Technology (BACT) Guidelines for VOC Emitting Sources, June 11, p. 29; Available at: <http://www.mass.gov/eea/docs/dep/air/approvals/bactvoc.pdf>.

F. VOC BACT for the Crude Methanol Tank Scrubber

The Project includes a scrubber (EPN SV1-14) that will control VOC emissions from the fixed roof crude methanol tank.¹⁶⁸ Under normal operating conditions, the crude tank flash will be educted to the reformer fuel gas system, except during periods of educator downtime. During educator downtime, estimated as 176 hours/year,¹⁶⁹ crude tank flash gas will be vented to a scrubber.¹⁷⁰

The BACT analysis asserts, without performing a top-down BACT analysis, and with no support whatsoever, that BACT for the crude methanol tank is a scrubber with a 95% VOC removal efficiency.¹⁷¹ 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 (e.g., wet), 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.

Second, as noted in Section IV, BACT is an emission limit, not a control efficiency, which is an intermediate step in establishing an emission limit. See Section IV.A.3, Step 3. The BACT analysis failed to establish a BACT emission limit, which is required to satisfy Step 3 of the BACT analysis.

Third, the Application asserts with no support that: “A review of the RBLC database of permits issued after 2003 shows no BACT determinations related to this activity.” As noted in Section IV, the RBLC is only one of many sources that must be consulted when performing a BACT analysis.

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.¹⁷² Further, other information to be considered in determining the performance level representing achievable limits includes manufacturer’s data, engineering estimates, and the experience of other sources. The Applicant and agency must survey not only the RBLC, 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. None

¹⁶⁸ EDMS 10329019, Statement of Basis, pdf 145.

¹⁶⁹ EDMS 10329019, Specific Requirement 197, pdf 54.

¹⁷⁰ EDMS 10329019, Preliminary Determination Summary, pdf 116; January 2016 Application, pdf 718.

¹⁷¹ EDMS 10329019, January 2016 Application, Section 3.7, pdf 717-718.

¹⁷² NSR Manual, p. B.23.

of these sources were consulted in determining BACT for the scrubber. A review of a recent methanol plant 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:¹⁷³

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 ¹⁷⁴ and established BACT VOC permit limits of 0.72 ton/yr and 0.16 lb/hr. Further, while no control was proposed for CO, the SWCAA established BACT permit limits for CO of 0.72 ton/yr and 0.16 lb/hr.¹⁷⁵ The SLM CO BACT analysis failed to establish any BACT limit whatsoever for CO.¹⁷⁶

The similar Yuhuang methanol plant, also 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.¹⁷⁷

In sum, VOC BACT for the methanol product tank scrubber is 99% control.

V. THE CONDITIONS IN THE DRAFT PERMITS ARE NOT ENFORCEABLE

The Applicant applied for a major modification of existing PSD and Title V permits issued in 2013 for a facility that does not yet exist and for which construction has not started.

¹⁷³ Kalama Application, pdf 191.

¹⁷⁴ Southwest Clean Air Agency, Technical Support Document, Air Discharge Permit ADP 16-3204, Draft, November 21, 2016, pdf 10, 19 (manufacturer specifications); Available at: <http://www.swcleanair.org/docs/permits/prelim/16-3204TSD.PDF>.

¹⁷⁵ Kalama Draft Permit, Condition 11, pdf 9.

¹⁷⁶ EDMS 10329019, Specific Conditions, pdf 123.

¹⁷⁷ 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 (Ex. 2, Attachment F), available at <http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=10239485&ob=yes&child=yes>.

For any physical or operational limitation on the facility's emissions, permit conditions and limitations must be both legally and "practically enforceable."

The Clean Air Act requires that permits be practically enforceable. The U.S. EPA has emphasized that point. "Practicable enforceability" means that a permit's provisions must specify:

- (1) A technically-accurate limitation and the source subject to the limitation;
- (2) the time period for the limitation (hourly, daily, monthly, and annual limits such as rolling annual limits); and (3) the method to determine compliance including appropriate monitoring, recordkeeping, and reporting.¹⁷⁸

As the U.S. Environmental Protection Agency recently reiterated with respect to the Yuhuang Methanol Plant, "[o]ne of the key concepts in evaluating the enforceability of PTE limits is whether the limit is enforceable as a practical matter."¹⁷⁹ The conditions in the existing Title V and PSD permits and the proposed modification are not practically enforceable.

In the context of permitting, the term "practicably enforceable" is generally interpreted to require permit conditions and limitations that are enforceable as a practical matter.¹⁸⁰ Thus, "the permit must clearly specify how emissions will be measured or determined for purposes of demonstrating compliance" with permit limitations.¹⁸¹ Permit limitations or conditions must be supported by monitoring, recordkeeping, and reporting requirements which are sufficient to enable both regulators and citizens alike to determine whether a limit has been exceeded, and if so, to take appropriate enforcement action.¹⁸² Many conditions in the proposed modified permits are not practicably enforceable.

The vast majority of the emission limits in these permits are BACT emission limits. The NSR Manual explains that the last step in the top down BACT process used by the Applicant is to establish an enforceable emission limit.¹⁸³

¹⁷⁸ 73 Fed. Reg. 1570, 1573 (Jan. 9, 2008).

¹⁷⁹ Yuhuang Order, p. 14.

¹⁸⁰ *Id.*

¹⁸¹ *Id.*

¹⁸² *Id.*

¹⁸³ NSR Manual, p. B.56-B.57.

To complete the BACT process, the reviewing agency must establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source. If technological or economic limitations in the application of a measurement methodology to a particular emission unit would make an emissions limit infeasible, a design, equipment, work practice, operation standard, or combination thereof, may be prescribed. Also, the technology upon which the BACT emissions limit is based should be specified in the permit. These requirements should be written in the permit so that they are specific to the individual emission unit(s) subject to PSD review.

The emissions limits must be included in the proposed permit submitted for public comment, as well as the final permit. BACT emission limits or conditions must be met on a continual basis at all levels of operation (e.g., limits written in pounds/MMBtu or percent reduction achieved), demonstrate protection of short term ambient standards (limits written in pounds/hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements). Consequently, the permit must:

- ! be able to show compliance or noncompliance (i.e., through monitoring times of operation, fuel input, or other indices of operating conditions and practices); and
- ! specify a reasonable averaging time consistent with established reference methods, contain reference methods for determining compliance, and provide for adequate reporting and recordkeeping so that the permitting agency can determine the compliance status of the source.

Elsewhere, the NSR Manual explains:¹⁸⁴

limits are often best expressed in tabular rather than textual form. In general, it is best to express the emission limits in two different ways, with one value serving as an emissions cap (e.g., lbs/hr.) and the other ensuring continuous compliance at any operating capacity (e.g., lbs/MMBtu). The permit writer should keep in mind that the source must comply with both values to demonstrate compliance. Such limits should be of a short term nature, continuous and enforceable. In addition, the limits should be consistent with the averaging times used for dispersion modeling and the averaging times for compliance testing. Since emissions limitation values incorporated into a

Since the PSD Permit terms and conditions will also eventually be incorporated as part of the federal Title V operating permit, known as a Federally Enforceable State Operating Permit (“FESOP”) at the state level, law and guidance on enforceability in the Title V context also are instructive.

Pursuant to the Clean Air Act, Title V permits are to include, among other conditions, “*enforceable* emission limitations and standards, ... and such other conditions as are necessary to assure compliance with applicable requirements of [the Act], including the requirements of the applicable implementation plan.” 42 U.S.C. § 7661c(a) (emphasis added). U.S. EPA policy requires Title V permits to be “enforceable as a practical matter.”¹⁸⁵ Thus, to be enforceable, the permit must create mandatory obligations (standards, time periods, methods). Specifically, a permit condition must: (1) provide a clear explanation of how the actual limitation or requirement applies to the facility; and (2) make it possible for the [state agency], the U.S. EPA, and citizens to determine whether the facility is complying with the condition.¹⁸⁶ Title V permits must contain monitoring and reporting requirements to allow citizen enforcement, in addition to State and Federal Regulators’ ability to enforce the Title V permits.

The U.S. EPA has provided examples of permit conditions that are not enforceable as a practical matter in a letter to the Ohio Environmental Protection Agency (“OEPA”) setting out deficiencies in Ohio’s Title V program. In that letter, EPA explained that, “In addition to implementing appropriate compliance methods, the monitoring, recordkeeping, and reporting requirements must be written in sufficient detail to allow *no room for interpretation or ambiguity*

¹⁸⁴ NSR Manual, p. H.5.

¹⁸⁵ See U.S. Environmental Protection Agency, Region 9, Title V Permit Review Guidelines: Practical Enforceability, September 9, 1999, (hereafter “Region 9 Guidelines”) ; Available at: http://webcache.googleusercontent.com/search?q=cache:P7YnEX6ssOkJ:itepsrv1.itep.nau.edu/itep_course_downloads/TitleV_Resources/R9TitleVPermitReviewGuidelines_FULLL.pdf+&cd=1&hl=en&ct=clnk&gl=us.

¹⁸⁶ See, e.g., *Sierra Club v. Ga. Power Co.*, 365 F. Supp. 2d 1297, 1308 (D. Ga. 2004) (citing *Sierra Club v. Public Serv. Co.*, 894 F. Supp. 1455, 1460 (D. Colo. 1995)).

*in meaning. Requirements that are imprecise or unclear make compliance assurance impossible.*¹⁸⁷

Similarly, U.S. EPA policy explains that for a permit condition to be enforceable, the permit must leave no doubt as to exactly what the facility must do to comply with the condition.¹⁸⁸

A permit is enforceable as a practical matter (or practically enforceable) if permit conditions establish a clear legal obligation for the source [and] allow compliance to be verified. Providing the source with clear information goes beyond identifying the applicable requirement. It is also important that permit conditions be unambiguous and do not contain language which may intentionally or unintentionally prevent enforcement.¹⁸⁹

The “practical enforceability” requirement is necessary “to assure the public’s and EPA’s ability to enforce the title V permit is maintained, and to clarify for the title V source its obligations under the permit.” *Id.* at III-56. Citizens do not have the powers at their disposal that agencies have (i.e., the power to conduct an inspection, the power to require the submittal of records or documents by the permittee, or the power to reopen a permit). As a result, the permit must be self-contained (include all terms, definitions and conditions that are necessary to enforce the permit) and must be clear in order to be practically enforceable. *See generally, id.* at III-57 to III-62.

The subject St. James Methanol Plant permits are notable for their lack of emission monitoring and reporting. The only emission monitoring required is for NO_x emissions from the reformer vent and boilers. No monitoring at all is required for all other sources and for all other criteria pollutants and hazardous air pollutants (HAPs).¹⁹⁰ Thus, with the exception of NO_x emissions from the reformer vent and boilers, the conditions in these permits are not enforceable as a practical matter. Some examples follow.

¹⁸⁷ See Letter from Bharat Mathur, U.S. Environmental Protection Agency, Region 5, to Robert F. Hodanbosi, Ohio Environmental Protection Agency, November 21, 2001 (emphasis added) (Ex. 2, Attachment G).

¹⁸⁸ Region 9 Guidelines, at III-55.

¹⁸⁹ *Id.*

¹⁹⁰ EDMS 10329019, Statement of Basis, pdf 158.

A. Emissions From The Boilers Are Not Enforceable

The facility includes two boilers. The PSD analysis established specific BACT emission limits for these boilers as summarized in Table 2.

Table 2. BACT Emission Limits for the Boilers.¹⁹¹

PM/PM ₁₀ /PM _{2.5}	0.005 lb/MMbtu	Good Combustion Practices & Use Pipeline Quality Natural Gas	1.75	Lbs/hr
NO _x	0.01 lb/MMbtu	Selective Catalytic Reduction, Low NO _x Burners, & Good Combustion Practices	3.50	Lbs/hr
CO	0.038 lb/MMbtu	Good Combustion Practices	13.30	Lbs/hr
VOC	0.00539 lb/MMbtu	Good Combustion Practices	1.89	Lbs/hr
CO _{2e}	1.05 Ton CO _{2e} /Metric Ton of MeOH produced	Energy Efficiency Measures	179,511	TPY

Compliance with the NO_x limits will be determined using a Continuous Emission Monitoring System (CEMS). However, the boiler Title V Specific Requirements and PSD Specific Conditions do not require any testing at all for any of the other criteria pollutants. The permits must be modified to require testing to confirm compliance with the limits in Table 2. The Kalama Methanol Plant Preliminary Air Discharge Permit, for example, requires the use of a CEMS to determine compliance with the CO BACT limit.¹⁹² Compliance with all of the criteria pollutants in Table 2 should be determined using either CEMS, which are available for all of the criteria pollutants, or with sufficient justification for less frequent testing, mandatory annual stack tests.

B. Emissions From The Reformer Vent Are Not Enforceable

The facility includes a pre-reformer and steam methane reformer, together known as the Reformer. The Reformer consists of a rectangular insulated structure containing vertical tubes filled with catalyst. The Reformer feed flows through these catalyst-filled tubes. Heat is supplied from downward firing burners located on the roof of the Reformer which heat the outside of the tubes, converting the feedstock to a mixture of CO, CO₂, hydrogen, and methane, known as synthesis gas. Thus, the Reformer is a fired source.

The Reformer is the major source of PM/PM₁₀ (75%), PM_{2.5} (82%), NO_x (50%), VOC (52%), and CO_{2e} (76%) emissions and additionally contributes 17% of the CO.¹⁹³ The PSD analysis established specific BACT emission limits for the Reformer as summarized in Table 3. However, among these, only the NO_x limit is enforceable.

¹⁹¹ EDMS 10329019, pdf 121.

¹⁹² Kalama Preliminary Air Discharge Permit, Condition 99, pdf 18.

¹⁹³ EDMS 10329019, Sept. 2015 Application, Table 2.3, pdf 204.

Table 3. BACT Emission Limits for the Reformer.¹⁹⁴

PM/PM ₁₀ /PM _{2.5}	0.00745 lb/MMbtu	Good Combustion Practices & Use Pipeline Quality Natural Gas	23.46	Lbs/hr
NO _x	0.0121 lb/MMbtu	Selective Catalytic Reduction, Low NO _x Burners, & Good Combustion Practices	38.09	Lbs/hr
CO	0.0037 lb/MMbtu	Good Combustion Practices	11.65	Lbs/hr
VOC	0.00539 lb/MMbtu	Good Combustion Practices	16.97	Lbs/hr
CO _{2e}	1.05 Ton CO _{2e} /Metric Ton of MeOH produced	Energy Efficiency Measures	1,614,575	TPY

The proposed Title V and PSD permits do not require any testing to confirm compliance with any of these limits except NO_x. Compliance with the NO_x limits will be determined using a CEMS.¹⁹⁵ However, the Title V Specific Requirements and PSD Specific Conditions do not require any testing at all for any of the other criteria pollutants. The permits must be modified to require testing to confirm compliance with the limits in Table 3. Compliance with all of the criteria pollutants in Table 3 should be determined using either CEMS, which are available for all of the criteria pollutants, or with sufficient justification for less frequent testing, mandatory annual stack tests.

C. Emissions of CO_{2e} from Fired Sources Are Not Enforceable

LDEQ concluded, based on the Applicant's analysis, that BACT for CO_{2e} emissions from all fired sources (reformer, boilers) is the use of energy efficiency measures to achieve 1.05 tons CO_{2e}/metric ton methanol, as an annual average.¹⁹⁶ The proposed Title V and PSD permit conditions do not require the use of any specific energy efficiency measures, such as those identified in the record, e.g., regular burner maintenance, limits on excess air, the mandatory use of oxygen monitors and intake flow monitors to optimize the air-to-fuel mixture and limit excess air.¹⁹⁷ While the permits do require an annual tune-up to comply with 40 CFR 63.7540, this is part of the baseline and is not responsive to BACT efficiency measures.¹⁹⁸

Further, proposed Specific Requirement 314¹⁹⁹ allows CO_{2e} emissions to be calculated using "default" emission factors from 40 CFR 98, Tables C-1 and C-2, based only on fuel type, e.g., natural gas. No monitoring at all is required to confirm these "default" factors at fired sources in a methanol plant.

¹⁹⁴ EDMS 10329019, pdf 121.

¹⁹⁵ EDMS 10329019, pdf 44, Specific Requirement 68.

¹⁹⁶ EDMS 10329019, pdf 84.

¹⁹⁷ EDMS 10329019, pdf 82.

¹⁹⁸ See, e.g., EDMS 10329019, Specific Requirements 41 and 42, pdf 42 and Specific Requirements 57 and 58, pdf 43.

¹⁹⁹ EDMS 10329019, pdf 65.

The emission factor for CO₂ for natural gas fired sources, which comprises 99% of the total CO₂e, is a weighted U.S. average and is thus not specific to the facility's fired sources and natural gas supply. Further, the specific monitoring and QA/QC requirements at 40 CFR 98.34 that underpin the use of these factors are not specifically required in proposed Title V and PSD permits, but rather only the "recording" of the emissions. Thus, the CO₂e limits are not practically enforceable.

The draft permits should be modified to clarify that 40 CFR 98 in its entirety be followed, not just the use of emission factors in Tables C-1 and C-2. Further, the conditions should be modified to require that CO₂ be routinely measured from each fired source and the measurements used together with firing rates and production data to estimate unit emissions in tons of CO₂e per metric ton of methanol produced.

D. Emissions from the Flare Are Not Enforceable

The Facility includes two flare headers, a high pressure header (dry) and a low pressure (wet) header. The headers are routed to a knockout drum to remove liquids, a liquid seal drum and finally the flare stack. The PSD analysis established specific BACT emission limits for the Flare as summarized in Table 4. However, none of these limits is enforceable.

Table 4: BACT Emission Limits for the Flare.²⁰⁰

PM/PM ₁₀ , PM _{2.5} , NO, CO, VOC	Correct Flare Design and Proper Combustion	Compliance with NESHAP Subpart A for flare performance standards & 98% control efficiency.	1.41, 1.41 12.82, 58.44, 22.08	Lbs/hr,
CO ₂ e	Correct Flare Design and Proper Combustion	Compliance with NESHAP Subpart A for flare performance standards & 98% control efficiency.	1,949	TPY

The flare will serve as a control device for all sources at the Facility. The emissions from each of these sources were estimated in the Application based on assumptions including: (1) vented material fuel flow; (2) vented material characteristics, including molecular weight and heating value; (3) flare destruction efficiency; (4) operating hours for each vented stream; (4) stream chemical composition; and (5) AP-42 emission factors, among others.²⁰¹ The only monitoring specified, in Specific Requirement 101, is the flow rate to the flare.²⁰²

The proposed permits do not establish limits on any of the factors used to calculate flaring emissions, do not require any monitoring to assure that the assumptions used in the potential to emit calculations are achieved in practice, do not set out a calculation procedure to estimate flare emissions, or even require that these emissions be estimated and reported. Thus, flare emissions are not practically enforceable.²⁰³ The flare control efficiency is a key factor in

²⁰⁰ EDMS 10329019, pdf 122.

²⁰¹ EDMS 10329019, pdf 436-437.

²⁰² EDMS 10329019, Specific Requirement 101, pdf 47.

²⁰³ See EPA Yuhuang Order at 21-22.

the flaring emission calculations and is the basis of the BACT determination. Flare control efficiency can and should be demonstrated.

Flare emissions (VOC, CO, NO_x, and methanol) can be monitored in real time using passive Fourier Transform Infrared (pFTIR) spectroscopy or differential infrared absorption LIDAR (light detection and ranging) methods, as used by EPA recently to estimate emissions from commercial flares.²⁰⁴ Flare emission testing is essential to estimate actual emissions from the flare because the AP-42 emission factors used to estimate flare emissions are not representative of emissions from flares at methanol plants and methods do not exist to convert flare inlet concentrations, even if proposed for monitoring or estimating flare emissions, into outlet emissions.

Alternatively, compliance with flare emission limits can be demonstrated using a combination of three methods. First, the proposed permits could require that the flare vendor supply a guarantee for the subject efficiencies and supply the guarantee to the LDEQ. Second, the proposed permits could be modified to require video monitoring of the flare, as currently required in SJVAPCD Rule 4311 and that actions be taken to improve combustion efficiency when anomalous conditions are observed, e.g., flame detachment from the flare stack, soot, etc. Third, it is feasible to measure the combustion efficiency using various remote sensing methods such as passive FTIR, which has been required by the EPA in other situations.²⁰⁵

E. Emissions from the Crude Methanol Tank Are Not Enforceable

The BACT analysis and proposed PSD specific conditions indicate BACT for VOC emissions from the crude methanol tank is a fixed roof tank that vents to a scrubber with a 95% control efficiency.²⁰⁶ However, the proposed Title V Permit relaxes this condition, requiring only 95% control of “total organic HAP.”²⁰⁷ As organic HAPs are a small subset of total VOC emissions, this condition fails to satisfy BACT, which itself is flawed and should have been a VOC emission rate based on a 99% VOC control efficiency. See Section IV.F.

Further, the proposed permits do not include any monitoring to confirm that the crude methanol tank scrubber routinely achieves 95% control efficiency. The proposed permits should be modified to require periodic scrubber inlet and outlet monitoring to confirm the control efficiency as well as operation in accordance with manufacturer specification, and routine inspections. The Kalala permit, for example, requires annual emission testing to demonstrate

²⁰⁴ See references in footnote 202.

²⁰⁵ Marathon Petroleum Company, Performance Test of a Steam-Assisted Elevated Flare with Passive FTIR, Final Report, May 2010; Available at: <https://www.tceq.texas.gov/assets/public/implementation/air/rules/Flare/2010flarestudy/mpc-txc.pdf>; Thomas R. Blackwood, An Evaluation of Flare Combustion Efficiency Using Open-Path Fourier Transform Infrared Technology, *J. Air & Waste Manage. Assoc.*, v. 50, Oct. 2000, pp. 1714-1722 (Ex. 2, Attachment H).

²⁰⁶ EDMS 10329019, pdf 123.

²⁰⁷ EDMS 10329019, Specific Requirement 166, pdf 52.

compliance as well as other monitoring and quarterly visual inspections of internal components, with repair as soon as possible.²⁰⁸

F. Emissions from Miscellaneous Fired Sources Are Not Enforceable

The facility includes a 1474 HP diesel-fired emergency generator and 650 HP diesel-fired pump. The BACT analysis established emissions limits in g/BHP-hr, lbs./hr, and TPY (CO₂e) for this equipment for all criteria pollutants.²⁰⁹ The proposed permits do not contain any monitoring of criteria pollutants to demonstrate compliance with these limits. Rather, the permits rely only on restrictions of operating hours.²¹⁰ Thus, the BACT emission limits are not practically enforceable.

G. Emissions from the Cooling Towers Are Not Enforceable

The facility includes two cooling towers. The BACT analysis established a drift rate of 0.0005%²¹¹ for cooling tower CT-13 and of 0.001% for the Econamine cooling tower ECT-14 to limit PM/PM₁₀/PM_{2.5} emissions.²¹² No monitoring or reporting is required to assure continuous compliance with the drift rates and the PM/PM₁₀/PM_{2.5} emissions limits established as BACT, based on drift rate, circulating water flow rate, and total dissolved solids (TDS) concentration in the circulating water.

The proposed Title V permit for CT-14 only limits the drift rate to 0.001%, omitting all emission limits and cooling tower operating conditions.²¹³ No monitoring or reporting is required to determine continuous compliance with the drift rate or the circulating water flow rate and TDS concentration used to estimate particulate matter emissions.²¹⁴ Permits commonly require circulating water flow rate, TDS, and drift monitoring to confirm compliance.²¹⁵

The proposed Title V permit for CT-13 only limits the drift rate to 0.0005%, omitting all emission limits and operating conditions.²¹⁶ No monitoring or reporting is required to determine continuous compliance with the drift rate or the circulating water flow rate and TDS

²⁰⁸ Kalala Technical Support Document, pdf 31; Available at: <http://www.swcleanair.org/docs/permits/prelim/16-3204TSD.PDF>; Kalala Draft Permit, Appendix F, Condition 11, pdf 9 and Conditions 42-47; Available at: <http://www.swcleanair.org/docs/permits/prelim/16-3204ADP.PDF>.

²⁰⁹ EDMS 10329019, Specific Conditions, pdf 122-123.

²¹⁰ EDMS 10329019, Statement of Basis, pdf 158 and Specific Requirements, pdf 50, 51.

²¹¹ This is the percent of the circulating water flow rate that is emitted.

²¹² EDMS 10329019, Specific Conditions, pdf 122-123.

²¹³ EDMS 10329019, Specific Conditions 184 and 185, pdf 53.

²¹⁴ EDMS 10329019, pdf 435.

²¹⁵ See, e.g., M.W. Golay et al., Comparison of Methods for Measurement of Cooling Tower Drift, atmospheric Environment, v. 20, no. 2, 1986; Available at: <http://www.sciencedirect.com/science/article/pii/0004698186900302>.

²¹⁶ EDMS 10329019, Specific Conditions 95 and 96, pdf 47.

concentration used to estimate particulate matter emissions.²¹⁷ Permits commonly require circulating water flow rate, TDS, and drift monitoring to confirm compliance.

CONCLUSIONS

For the foregoing reasons, EPA should object to the Proposed Modified Title V Permit No. 2560-00292-V1 for South Louisiana Methanol.

Sincerely,



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²¹⁷ EDMS 10329019, pdf 434.