UNITED STATED ENVIRONMENTAL PROTECTION AGENCY
BEFORE THE ADMINISTRATOR

IN THE MATTER OF	*	PETITION FOR
	*	OBJECTION
Clean Air Act Title V Permit No. 2560-	*	
00295-V0	*	
	*	
Issued to Yuhuang Chemical Inc.	*	Permit No. 2560-00295-V0
	*	
Issued by the Louisiana Department of	*	
Environmental Quality	*	
	*	

PETITION REQUESTING THAT THE ADMINISTRATOR OBJECT TO ISSUANCE OF THE INITIAL TITLE V PERMIT FOR THE YUHUANG CHEMICAL METHANOL PLANT, PERMIT NO. 2560-00295-V0

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 (LEAN) petition the Administrator of the U.S. Environmental Protection Agency (EPA) to object to the initial Title V air operating air permit no. 2560-00295-V0 (Title V Permit) issued to Yuhuang Chemical Inc. for the construction and operation of a new methanol manufacturing plant in St. James, Louisiana.

Petitioners respectfully request that EPA object to the Title V Permit for the Yuhuang's methanol plant because it does not comply with the Clean Air Act. The Title V Permit is illegal because it fails to include emission limits and conditions of a Prevention of Significant Deterioration ("PSD") permit. LDEQ wrongfully determined that the methanol plant is not a major stationary source as defined by PSD regulations and therefore did apply any PSD requirements or issue a PSD permit for the plant. Final Permit, Air Permit Briefing Sheet, 3 ("The YCI Methanol Plant will be a minor source of criterial pollutants."); *see also* SOB,[1] p. 4. But as shown in detail below, the plant is a major source stationary source as defined by PSD

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[1] LDEQ, Statement of Basis (SOB), YCI Methanol Plant, Yuhuang Chemical Inc., St. James, St. James Parish, Louisiana, Activity No. PER20140001, 2015 (SOB).

regulations and therefore must have a PSD permit and comply with PSD regulations. In order for this Title V permit to comply with the Clean Air Act, it must incorporate the terms and conditions of a PSD permit.

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 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 Yuhuang Chemical does not comply with the Act's PSD requirements.

I. STATUTORY & REGULATORY FRAMEWORK

Section 502(d)(1) of the Clean Air Act, 42 U.S C. § 7661a(d)(l), 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, "[alny term or condition of any preconstruction permit" or "[alny 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 Yuhuang's 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)* and opportunity for the public to participate in the process. 40 U.S.C. § 7475(a)(2)-(8); *see also Alaska Dep't of Envtl. 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). 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, nl2 (2nd Cir. 2003)

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

Yuhuang Chemical Inc. submitted an application to LDEQ in October 2014 (10/14 Ap.),[2] to construct and operate a new methanol manufacturing plant in St. James, Louisiana. Yuhuang submitted a modified application on December 2014 (12/14 Ap.).[3] LDEQ issued a proposed permit for public comment on February 4, 2015. The public comment period for the proposed permit ended on March 16, 2015. Petitioners filed timely public comments with LDEQ regarding the proposed permit on March 16, 2015.

Under section 505(a) of the Act, 42 U.S.C. § 7661d(a), and 40 C.F.R. § 70.8(a), the

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[2] Letter from Bliss Higgins, Environ, to Tegan Treadaway, LDEQ, Re: Yuhuang Chemical Inc. Methanol Plant, October 31, 2014, attaching: Application for an Initial Title V Air Permit, Yuhuang Chemical Inc. (YCI) Methanol Plant, Prepared for: Yuhuang Chemical Inc., October 2014, available on LDEQ's EDMS Doc. ID. 9527280.

[3] Memorandum from Brian Glover, ENVIRON, to Bryan Johnston, LDEQ, Re: Response to Yuhuang Chemical Inc. Initial Permit Review Questions, December 12, 2014, available on LDEQ's EDMS Doc. ID. 9570680.

relevant implementing regulation, states are required to submit each proposed title V operating permit to EPA for review. On February 4, 2015, concurrently with the public comment notice, LDEQ submitted the proposed permit to EPA Region 6 for review. On March 10, 2015, Jeff Robinson of the EPA Region 6 Air Permits Division, submitted comments to LDEQ on the proposed permit. 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 March 20, 2015.

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. Ex. A, Fox Comments, Ex. B. Fox C. V. This petition is also based on comments prepared by EPA Region 6, which were also submitted during the public comment period. In addition, this petition incorporates further comments by Dr. Fox where she has responded to LDEQ’s Public Comment Response Summary issued on May 5, 2015 concurrently with the final Permit. RTC; Ex. C.

III. EPA MUST OBJECT BECAUSE THE PERMIT FAILS TO COMPLY WITH THE ACT’S RQUIREMENTS FOR PUBLIC PARTICIPATION.

40 C.F.R. §§ 70.5 provides, "[A]n application must provide all information required pursuant to paragraph (c) of this section . . . . Information required under paragraph (c) of this section must be sufficient to evaluate the subject source and its application and to determine all applicable requirements." § 70.5(c)(3) (listing required emissions related information including calculations on which the information is based and any additional information sufficient to verify which requirements are applicable to the source.).

Many of the emission factors used to calculate emissions are based on vendor-supplied inputs. The application states that the vendor-supplied data is based on information provided by Air Liquide in an excel spreadsheet. But the spreadsheet is not available in the permit record. EPA Region 6 and Petitioners asked LDEQ for this spreadsheet, but LDEQ argues that only the "calculations" must be provided, not the "inputs" to the calculations. This is incorrect. When the "inputs" themselves are calculations and/or when they are not referenced to a publicly available, verifiable source, the basis and supporting calculations must be provided. The public must be able to verify the accuracy of the inputs. Nowhere in the application is there any information about how the vendor determined those inputs. The application, therefore, fails to provide information sufficient to evaluate the sources of emissions to determine all applicable requirements.

IV. EPA MUST OBJECT TO THE PERMIT BECAUSE IT FAILS TO MEET PSD REQUIREMENTS.

As shown in detail below, the Yuhuang Methanol Plant is a major stationary source as defined by LAC 33:III.509.B because it has the potential to emit more than 100 tons per year each of NOx, VOCs, and CO and thus must meet the PSD requirements under LAC 33:III.509.J-R. LAC 33:III.509.A.2. But LDEQ did not require PSD review or a PSD permit because it wrongfully concluded that the plant is a minor source of PSD-regulated pollutants. The Title V permit for the plant is illegal because it fails to include emission limits and other conditions necessary to assure compliance with PSD requirements. 42 U.S.C. § 7661c(a).

For instance, the Title V permit does not include limits or other conditions that will ensure that the plant will not cause a violation of any NAAQS. The Title V permit is also fails to include limits that will assure compliance with BACT for each PSD-regulated pollutant emitted from sources at the proposed plant. Specifically, the Title V permit fails to impose BACT limits for PM, PM10, PM2.5, SO2, NOx, CO, VOCs, and GHGs (including carbon dioxide, nitrous oxide, and methane) emissions at the following sources: Steam Methane Reformer, Auxiliary Boiler, Flore, Emergency Generator, Firewater Pump No. 1, and Firewater Pump No. 2. The Title V permit also fails to impose BACT limits for PM, PM10, PM2.5 and VOCs emissions at the Cooling Tower. In addition, the Title V permit fails to impose BACT limits for VOC emissions from each source included in the Transfer and Storage Cap.

EPA must object and remand the permit to LDEQ for a proper tally of the plant's potential to emit NOx, VOCs, and CO as shown below. LDEQ must then require Yuhuang Chemical to obtain a PSD permit, the terms and conditions of which must be incorporated into a revised Title V permit.

A. <u>The NOx Emissions Exceed 100 ton/yr</u>.

The Statement of Basis ("SOB") and Application estimated total NOx emissions of 85.45 ton/yr from the following sources (SOB, p. 4; 12/14 Ap., Attach. A):

- SMR: 52.56 ton/yr
- Auxiliary Boiler: 23.08 ton/yr
- Flare: 7.25 ton/yr
- Emergency Generator 2.16 ton/yr
- Firewater Pumps: 0.40 ton/yr

The NOx emissions from the flare, SMR, and auxiliary boiler were underestimated. When the underestimates are corrected, total NOx emissions exceed 100 ton/yr.

1. The Flare NOx Emissions are Underestimated.

The NOx emissions from the flare alone are large enough to classify the Facility as a major source because non-routine flaring emissions exceed 100 ton/yr. The flare system collects and combusts vapors generated during startups and shutdowns (SU/SDs) plus various routine streams. 10/14 Ap., p. 2-3. The NOx emissions from these flaring events were estimated in the Application as 7.25 ton/yr, from the following activities (12/14 Ap., pdf[4] 34-40):

- Once-through nitrogen heating: 0.0274 ton/yr
- Startup/Shutdown Methanol Unit: 4.43 ton/yr
- Methanol Catalyst Reduction: 2.66 ton/yr
- Methanol purge: 0.01 ton/yr
- Flare Pilot: 0.13 ton/yr

a. The Applicant Excluded the Safety Factor from NOx Potential to Emit.

The 12/14 Application explains that a safety factor was added to annual emissions for the flare to account for the final design case. 12/14 Ap., pdf 2, Question 7. This safety factor was applied to the VOC emissions from the flare but not to other pollutants emitted from the flare, such as NOx, CO and PM10, even though the same calculation procedures and flare operating conditions are applicable.

The VOC emission calculations include a safety factor of 44, which was applied to the average hourly flare VOC emission rate. This safety factor was not applied to NOx emissions from the flare. The NOx emissions from the flare were estimated as 7.87 ton/yr, comprising the sum of emissions from the pilot (0.01 ton/yr); nitrogen heating (0.0011 ton/yr); methanol unit startup (0.0096 ton/yr); methanol catalyst regeneration (0.006 ton/yr); and intermittent purge

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[4] **All citations to pdf page numbers of the 12/14 Ap. refer to the pdf as downloaded from the EDMS Doc. ID 9570680.**

stream (0.15 ton/yr). 12/14 Ap., pdf 34-40. This works out to an average hourly emission rate of 1.66 lb/hr, which was used to calculate the potential to emit NOx from the flare of 7.25 ton/yr. If the same safety factor is used to estimate NOx emissions as was used for VOCs (44), NOx emissions from the flare increase from 7.25 ton/yr to 319 ton/yr. Thus, as the flare NOx emissions alone exceed the major source threshold of 100 ton/yr, the Facility is a major source and must go through PSD review.

In response to this argument, LDEQ simply responded that "a safety factor will not be applied to calculated emissions of PM10/PM2.5, NOx, or CO" because Yuhuang has reevaluated potential emissions from the flare and determined that a safety factor is not necessary. RTC, 19. For support, LDEQ references EDMS Doc. ID. 9737811, Ex. D. But this document is just Yuhuang's revised emission calculations without a safety factor. It provides no explanation or reasoning as to why the safety factor was removed. Therefore, this is an inadequate response and another reason why the application is incomplete.

b. The flare emissions exclude emissions from upsets.

The flare emissions exclude emissions from upsets. The description of once-through nitrogen heating, start-up of the methanol unit, and methanol catalyst reduction states that "[e]missions from upsets are not included in this emissions estimate." 12/14 Ap., pdf 36. Upset emissions must be included in the potential to emit calculation. The Application does not estimate these emissions, but it does report a maximum hourly NOx emission rate of 184.46 lb/hr. 12/14 Ap., pdf 34. If there were 1,084 hours of upset conditions at this maximum emission rate in any given year, NOx emissions from upsets alone would exceed 100 ton/yr. Further, the proposed permit does not require any monitoring or reporting of flare upset events.

LDEQ claims that it need not count upset emissions because "[t]he permit does not authorize emissions associated with upsets." RTC Comment 20 (citing LAC 33:III.501.B.1.d.). But LDEQ must count emissions associated with malfunctions to determine the source's potential to emit. In the alternative, LDEQ must place a prohibition on such emissions that is legally and practically enforceable.

B. The Carbon Monoxide Emissions Exceed 100 ton/yr.

The SOB assumes total CO emissions of 88.30 ton/yr. SOB, p. 4. These emissions arise from the following sources (12/14 Ap., pdf 5):

- Steam Methane Reformer: 34.78 ton/yr
- Auxiliary Boiler: 49.67 ton/yr
- Flare: 2.34 ton/yr
- Emergency Generator: 1.17 ton/yr
- Fire Water Pumps: 0.14 ton/yr

The CO emissions from the SMR, auxiliary boiler and flare are underestimated. Further, the conditions in the proposed permit are inadequate to assure that the assumed CO emissions in the potential to emit calculation would be achieved. Some of the more egregious underestimates are discussed below.

Carbon monoxide emissions from fired sources are estimated by multiplying the concentration of CO in the gas stream, typically expressed in parts per million by volume (ppmv) or pounds per million standard cubic feet of gas (lb/MMscf), by the design firing rate in millions of British thermal units per hour (MMBtu/hr) and converting units to arrive at pounds per hour (lb/hr) and tons per year (ton/yr).

1. The CO Emissions from the Auxiliary Boiler are Underestimated.

The auxiliary boiler is the major source of CO emissions, contributing 49.67 ton/yr or 56% of the total CO. The auxiliary boiler CO emissions were calculated assuming natural gas combustion in a boiler, emitting 30 ppmv dry basis of CO, adjusted to 3% O_2. 10/14 Ap., Auxiliary Boiler Emissions Calc. The Application does not provide any basis for selecting this CO concentration to estimate CO emissions from the auxiliary boiler. It is much lower than CO emissions from comparable boilers.

The Application estimated emissions of all other criteria pollutants (PM, PM10, PM2.5, VOC, and SO2) from the auxiliary boiler using emission factors from EPA's "Compilation of Air Pollutant Emission Factors, Volume 1" (AP-42), Table 1.4-2. 10/14 Ap., Auxiliary Boiler Emissions Calc. This section of AP-42 contains standard EPA emission factors for combustion of natural gas in boilers without add-on pollution control. These AP-42 factors were not used for NOx because it is controlled by SCR, an add-on pollution control system. These emission factors are used to estimate emissions from natural gas fired boilers, in the absence of advanced pollution control systems (SCR, oxidation catalysts) or vendor guarantees, supported by enforceable permit limits.

The AP-42 emission factor for CO for natural gas fired boilers is 84 lb/10^6 scf. AP-42, Table 1.4-1. This corresponds to about 100 ppm dry basis at 3% O2, which is over a factor of three higher than assumed in the Application's CO emission calculation for the auxiliary boiler. The Application contains no justification for lowering the standard boiler CO emission factor from 100 ppm to 30 ppm.

Further, the proposed permit does not contain sufficient monitoring to confirm that this anomalously low CO limit is achieved in practice. The proposed permit only requires an initial stack test and subsequent tests every 5 years (Permit Condition 78). A stack test typically last three hours and is conducted under ideal operating conditions, generally after the source is tuned up, which would minimize CO emissions compared to routine operation. A three hour optimal snap shot every 5 years is not adequate to assure the CO emissions remain below the 100 ton/yr major source threshold and comply with the auxiliary boiler CO emission rates.

The CO emissions from the auxiliary boiler when estimated using the standard EPA emission factor for natural gas combustion in boilers, consistent with the factors chosen in the Application for other criteria pollutants, are over three times higher than disclosed in the Application (100/30 = 3.3).

The revised CO emissions from the auxiliary boiler are thus 166 ton/yr.[5] Therefore, the CO emissions from the auxiliary boiler alone are high enough to classify the Facility as a major source for purposes of PSD review. If the Applicant wishes to base the CO emissions on 30 ppm, the proposed permit must be modified to require the use of an oxidation catalyst to control CO emissions and a CO CEMS must be required to continuously measure CO to demonstrate compliance.

In its response to comments, LDEQ inadequately responds to this issue raised by Dr. Fox in her comments. While LDEQ argues that vendor data is more accurate that AP-42 emission factors, this must be supported by a vendor guarantee and must be made enforceable as a practical matter by permit conditions. However, here, there is no vendor guarantee in the record to support the claim. Further, the permit does not require any CO monitoring to demonstrate that this boiler will routinely, as well as during startup, shutdown, and malfunction, meet the asserted CO concentration of 30 ppm. Instead, it asserts that the auxiliary boiler will be equipped with a “continuous oxygen trim system” that will “continuously measure and maintain the optimum air to fuel ratio. Therefore, a CO CEMS is not required.” RTC, Comment 21. LDEQ’s response is not responsive to Dr. Fox’s comment.

First, the permit does not require the use of a continuous oxygen trim system on the

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[5] Revised CO emissions from auxiliary boiler, using AP-42 CO emission factor: 49.67 ton/yr x 3.3 = **165.6 ton/yr**.

auxiliary boiler.

Second, an oxygen trim system does not measure CO, but rather measures and maintains an optimum air-to-fuel ratio in the boiler combustion zone and provides feedback to automatically position the air damper to the proper position to maintain a set point of excess air. This procedure does not guarantee that any specific CO concentration will be achieved but does indirectly limit CO if continuously used as an environmental instrument, is properly calibrated, oxygen levels are continuously recorded, and resulting data are submitted to LDEQ. The permit does not require any of this.

Third, if an oxygen trim system were proposed as a surrogate for measuring CO, it must be operated to demonstrate continuous compliance with the assumed 30 ppm CO concentration used to establish minor source status. Thus, it must be operated at all times, be installed, calibrated, maintained, and operated to assure the assumed CO concentration of 30 ppm is met; and the measured data must be quality-assured to verify accuracy. The permit does not require any of this.

Fourth, an oxygen trim system adversely impacts boiler operation during startup, shutdown, and malfunction, as it would require that the boiler operate against a set point that could not be met during these periods. Thus, it would exclude emissions during these periods, which must be included to continuously demonstrate the source is minor for CO.

2. The CO Emissions from the Steam Methane Reformer are Underestimated.

The steam methane reformer (SMR) is the second largest source of CO emissions, contributing 34.78 ton/yr or 39% of the total CO. The SMR CO emissions were calculated assuming natural gas combustion in a boiler, emitting 10 ppmv CO dry basis, adjusted to 3% O2. 10/14 Ap., Steam Methane Reformer Emission Calc. The Application states this is based on information provided by Air Liquide, but the cited document is not in the record, and thus cannot be reviewed or verified. This is a very low CO concentration for natural gas combustion, as discussed for the auxiliary boiler.

The Application estimated emissions of other criteria pollutants (PM, PM10, PM2.5, VOC, and SO2) from the SMR using AP-42 emission factors for natural gas combustion in boilers, as previously discussed for the auxiliary boiler. AP-42, Table 1.4-2. These AP-42 factors were not used for NOx because it is controlled by SCR. The AP-42 emission factor for CO from natural gas fired boilers is 84 lb/10^6 scf. AP-42, Table 1.4-1. This corresponds to about 100 ppm dry basis at 3% O_2, which is about a factor of ten higher than assumed in the Application's CO emission calculations for the SMR.

An SMR can be operated at lower CO concentrations than a conventional natural gas fired boiler. However, this requires operation below the CO breakpoint, or at O_2 levels above the knee of the CO-O_2 curve. [6] The Application does not discuss the effect of oxygen level and temperature on CO emissions from the SMR and does not recommend any conditions to assure the very low CO concentration assumed in the emission calculations is achieved in practice.

Further, the proposed permit does not contain sufficient monitoring to confirm that this anomalously low CO limit is achieved in practice. It only requires an initial stack test and subsequent tests every 5 years (Permit Condition 38). A stack test typically lasts only three hours and is conducted under optimal operating conditions, generally after tuning. A three hour snap shot every 5 years under ideal operating conditions is not adequate to assure continuous compliance with a CO emission limit, especially one that is much lower than typically assumed for similar sources and which is known to vary significantly depending upon operating

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[6] Kunz, R.G.; Smith, D.D.; Adamo, E.M. "Predict NOx from Gas-Fired Furnaces" Hydrocarbon Processing Nov. 1996, 75(11), 65-79.

conditions. Thus, the proposed permit does not assure total Facility CO emissions remain below the 100 ton/yr major source threshold.

The CO emissions from the SMR , when estimated using the standard EPA emission factor for natural gas combustion in boilers, consistent with the factors chosen in the Application for other criteria pollutants, is ten times higher than disclosed in the Application (100/10 = 10).

The revised CO emissions from the SMR, using the standard AP-42 emission factor of 100 ppm, are 348 ton/yr.[7] Thus, potential CO emissions from the SMR alone are high enough to classify the Facility as a major source for purposes of PSD review. If the Applicant wishes to base the CO emissions on 10 ppm, the proposed permit must be modified to specify temperature and oxygen operating ranges, require a CO CEMS, and continuously monitor CO, temperature, and oxygen to assure the CO emission limits are satisfied.

LDEQ's response asserts that vendor data is more accurate than AP-42 emission factors. This generally assertion must be supported by a vendor guarantee and must be made enforceable as a practical matter by permit conditions. RTC Comment 22. However, here, there is no vendor guarantee in the record to support the claim. Further, the permit does not require continuous CO monitoring to demonstrate that the SMR will routinely, as well as during startup, shutdown, and malfunction, meet the asserted but unsupported CO concentration of 10 ppm.

3. The Maximum Emission Rate is Not Used to Calculate Potential to Emit.

The emission calculations report average and maximum hourly emission rates. However, the calculation of the potential to emit, in tons per year, is based only on the average emission rate and excludes upset emissions and all operation at the maximum emission rate. The potential to emit must be used to determine if a source is major. The potential to emit should be calculated

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[7] Revised CO emissions from SMR, using AP-42 CO emission factor: 34.78 x 10 = **347.8 ton/yr**.

from the maximum emission rate, unless otherwise limited by enforceable emission limits or facility design.

There is nothing in the proposed permit that would prohibit the major combustion sources, the SMR, auxiliary boiler or flare, from operating at their maximum emission rate continuously. This would result in the SMR, auxiliary boiler, and flare individually exceeding 100 ton/yr CO. The maximum CO emissions, absent an enforceable limit to the contrary, from the SMR would be 348 ton/yr;[8] from the auxiliary boiler, 166 ton/yr;[9] and from the flare, 231 ton/yr.[10] Even if these sources operated only part of the time at the maximum rates, they can exceed the 100 ton/yr limit. For example, if the SMR operated only 20% of the time or 1,826 hours at the maximum rate of 79.4 lb/hr and the balance of the time at the average CO emission rate of 7.94 lb/hr, the total CO emissions would be 100 ton/yr.

LDEQ responded, with no proof or conditions requiring limited operation at these levels, that there are no viable operating scenarios in which the SMR, auxiliary boiler, or flare could operate at their maximum emission rates continuously. RTC Comment 23. However, Dr. Fox's comment, which is restated here, demonstrated that continuous operation at these rates is not required to classify the source as major. Partial operation of any one of them or combination of them would exceed the major source threshold for CO. There are many combinations of operation of the various sources at much less than continuous operation that would result in this source being classified as major. The permit must be modified to limit the number of hours that each source may operate at the maximum rate and these conditions must be made enforceable.

LDEQ also asserts that "the ton per year limits of the permit also serve to restrict

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[8] Maximum annual CO emissions from the SMR: (79.4 lb/hr)(8,760 hr/yr)/2000 lb/ton = **347.8 ton/yr**.

[9] Maximum annual CO emissions from the auxiliary boiler: (37.8 lb/hr)(8,760 hr/yr)/2000 lb/ton = **165.6 ton/yr**.

[10] Maximum annual CO emissions from the flare: (52.82 lb/hr)(8,760 hr/yr)/2000 lb/ton = **231.35 ton/yr**.

potential to emit" because the limits in the permit "are both federally enforceable and enforceable as a practical matter." RTC Comment 23. But there are no such limits that are federally enforceable and enforceable as a practical matter. Because there are no limits that are federally enforceable and enforceable as a practical matter, the emissions from these events must be included in the source's potential to emit.

4. The Flare Safety Factor were Excluded from CO Potential to Emit.

The 12/14 Application explains that a safety factor was added to annual emissions for the flare to account for the final design case. 12/14 Ap., pdf 2, Question 7. This safety factor was applied to the VOC emissions but not to other pollutants emitted from the flare, such as NOx, CO, and PM10, even though the same calculation procedures, flare design basis, and flare operating conditions are applicable.

The VOC emission calculations include a safety factor of 44, which was applied to the average hourly flare VOC emission rate.[11] A safety factor was not applied to CO emissions from the flare. The CO emissions from the flare were estimated as 2.34 ton/yr, comprising the sum of emissions from the pilot (0.13 ton/yr); startup/shutdown (2.18 ton/yr); and purge (0.03 ton/yr). 12/14 Ap., pdf 34. This works out to an average hourly emission rate of 0.53 lb/hr,[12] which was used to calculate the potential to emit CO from the flare of 2.34 ton/yr.[13] If the same safety factor is used to estimate CO emissions as was used for VOCs (12/14 Ap., pdf 44), CO emissions from the flare increase from 2.34 ton/yr to 103 ton/yr.[14] Thus, as the flare CO emissions alone

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[11] Average hourly VOC emission rate, based on ton/yr (12/14 Ap., pdf 34): (0.01 + 0.02 + 0.15 ton/yr)(2000 lb/ton)/8760 hr/yr = 0.041 lb/hr. The hourly emission rate used to calculate annual emissions was 1.80 lb/hr, viz., (1.80 lb/hr)(8760 hr/yr)/2000 lb/ton = 7.88 ton/yr. The 12/14 Ap. at pdf 34 reports 7.87 ton/yr total VOC emissions from the flare. Thus, the safety factor incorporated in the flare VOC emissions calculations is: 1.80 lb/hr/0.041 lb/hr = **43.9**.

[12] Average hourly CO emission rate: (0.13 + 2.18 + 0.03 ton/yr)(2000 lb/ton)/8760 hr/yr = **0.53 lb/hr**.

[13] Potential to emit CO from the flare = (0.53 lb/hr)(8760 hr/yr)/2000 lb/ton = **2.32 ton/yr.**

[14] CO emissions, assuming VOC safety factor of 44: (2.34 ton/yr)(44) = **103 ton/yr**.

exceed the major source threshold of 100 ton/yr when the safety factor is included in the calculations, the Facility is a major source and must go through PSD review.

In response to this argument, LDEQ simply responded that “a safety factor will not be applied to calculated emissions of PM10/PM2.5, NOx, or CO” because Yuhuang has reevaluated potential emissions from the flare and determined that a safety factor is not necessary. LDEQ RTC Comment 24. For support, LDEQ references EDMS Doc. ID. 9737811, Ex. D. But this document is just Yuhuang’s revised emission calculations without a safety factor. It provides no explanation or reasoning as to why the safety factor was removed. Therefore, this is an inadequate response and another reason why the application is incomplete.

5. The Flare CO Emissions are Underestimated.

The CO emissions from the flare were underestimated by failing to include CO emissions from upsets.

The flare emissions exclude emissions from upsets. The description of once-through nitrogen heating, start-up of the methanol unit, and methanol catalyst reduction states that “[e]missions from upsets are not included in this emissions estimate.” 12/14 Ap., pdf 36. Upset emissions must be included in the potential to emit calculation. The Application does not estimate these emissions, but it does report a maximum hourly CO emission rate of 52.82 lb/hr. 12/14 Ap., pdf 34. At this rate, if there were 3,786 hours of upset conditions at this maximum emission rate in any given year, CO emissions from upsets alone would exceed 100 ton/yr. The proposed permit does not require any monitoring or reporting of flare upset events.

LDEQ claims that it need not count upset emissions because “[t]he permit does not authorize emissions associated with upsets.” RTC Comment 25 (referencing RTC Comment 20). But LDEQ must count emissions associated with malfunctions to determine the source’s potential to emit. In the alternative, LDEQ must place a prohibition on such emissions that is legally and practically enforceable.

6. The Fugitive CO Emissions were Excluded from the Emission Calculations.

Fugitive emissions are equipment leaks from pumps, compressors, valves, and connectors. The Steam Methane Reformer (SMR) uses a catalyst in the presence of steam to reform methane from natural gas into a raw syngas stream composed primarily of hydrogen, CO, and carbon dioxide. 10/14 Ap., p. 1-1 The CO concentrations in this stream are very high. Other streams in the proposed Facility will also contain very high CO concentrations.[15] Any fugitive components that handle these high CO streams – compressors, pumps, valves, flanges – will emit large amounts of CO. This source of CO was omitted from the emission calculations.

LDEQ's response to comments states that revised emission calculations indicate "only 0.14 tons per year based on the maximum weight percent of CO in the fuel gas system." RTC Comment 26. The supporting calculations at pdf 14 indicate that CO emissions from fugitive components were only calculated for the fuel gas system, assuming 7.1% CO in the gas stream, based on vendor data not included in the record or limited by the permit. This is not responsive because fuel gas is not the only stream that would contain CO that could be emitted from fugitive components. The major source of fugitive emissions is the non-fuel gas system, which emits 73% of the VOC and has streams with much higher CO concentrations than the fuel gas. Thus, the emission calculations have failed to account for all sources of CO and the permit fails to limit the potential to emit below the PSD significance threshold.

C. <u>The VOC Emissions Exceed 100 tons/yr</u> .

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[15] *See, e.g.,* K. Aasberg-Petersen, C.S. Nielsen, I. Dybkjaer, and J. Perregaard, Large Scale Methanol Production from Natural Gas, Feb. 2014, Available at: http://www.topsoe.com/file/large-scale-methanol-production-natural-gas.

The SOB reported the potential to emit for VOC emissions of 80.49 tons/yr (SOB, pdf 4) from the sources listed in Table 1. 12/14 Ap., pdf 5. The Application significantly underestimated the potential to emit VOCs. The revised VOC emissions, based on my review of the record, are summarized in Table 1. My calculations, discussed below, indicate that the Facility has the potential to emit more than 100 ton/yr of VOCs and is thus a major source.

Table 1:
VOC Emissions (ton/yr)

	12/14/ Ap.	Revised
5 methanol product tanks	6.04	8.46
1 crude methanol tank	3.19	9.32
Tank roof landing losses	-	7.1
Methanol loading	6.66	23.3-282
Fugitives	3.98	
SMR	28.34	32.6
Auxiliary Boiler	12.48	20.7
Flare	0.17	>0.17
Emergency Generator	0.50	
Firewater Pump #1	0.07	
Firewater Pump #2	0.07	
Cooling Tower	8.65	
Wastewater Treatment	3.00	
TOTAL	**80.49**	**117.9 – 376.6**

1. The Methanol Transfer and Storage Cap (MTSCAP) is Not Enforceable.

The emissions from six storage tanks and methanol truck, railcar, and marine loading operations are lumped together in a cap, a single annual emission limit of 15.9 ton/yr of VOCs that covers all of these processes. SOB, p. 11; 12/14 Ap., Attach. E., pdf 22. This cap is referred to as the Methanol Transfer and Storage Cap (MTSCAP), ID GRP 0001 in the proposed permit or simply “cap” in these comments. Permit, pdf 27.

The proposed permit limits emissions from the cap to 15.90 tons per 12-consecutive month period. Permit, Condition 214, pdf 52. This condition only requires: “Record VOC/methanol emissions each month and total VOC/methanol emissions for the preceding twelve months.” Id. The permit does not explain how the emissions would be determined for purposes of recording. Presumably, they would be calculated, using the AP-42 equation used in the Application, but the proposed permit fails to specify any calculation method. Calculations require inputs, actual measurements of factors used in the calculation, such as vapor pressure and temperature. The permit also does not impose any conditions, such as throughputs or vapor pressure and temperature limits. The permit also does not required any monitoring of calculation inputs to assure calculated VOC emissions would be met nor identify the method(s) that must be used to calculate emissions.

A recent report by EPA, for example, explains that the equations in AP-42, used to estimate emissions from all sources in the cap, “can inaccurately estimate emissions when default values are used inappropriately or when site-specific inputs are not entered into the equations…. Emissions from tanks that are improperly operated, defective (e.g. damaged floating roof rim seals and deck fitting), or in disrepair cannot be accurately estimated using these methods.”[16] The proposed permit does not require that calculations used to determine compliance (and that were used to estimate potential to emit) account for site-specific conditions and unusual emissions that occur as a result of process upsets, malfunctions, startups and shutdowns.

VOC emissions depend on the vapor pressure of the material that is stored and transferred. The vapor pressure, in turn, depends on material temperature. See, for example, 10/14 Ap., Appx. A. Thus, the permit must include limits on vapor pressure and temperature for

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[16] EPA, Draft EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems, p. 32, August 2014, Available at: http://www.epa.gov/ttn/chief/consentdecree/draft_report_review.pdf.

storage tanks and loading operations to ensure enforceability. The permit must also require that the vapor pressure and temperature be monitored periodically. Finally, the method to be used to calculate emissions, once the inputs are measured, must be specified.

The permit is missing all three of these essential ingredients to assure enforceability. This is particularly critical here as the Facility is being permitted as a minor source. This permit does not set any limits on calculation inputs or require monitoring of these inputs to assure that the Facility operates as a minor source. The permit, as drafted, would allow the Applicant to simply assert an emission level without any obligation to demonstrate the Facility is actually meeting it. As explained below, the Application has significantly underestimated VOC emissions. The revised emissions exceed the major source threshold of 100 ton/yr.

LDEQ's response to this comment, RTC Comment 26, is inadequate. The final permit does not require any monitoring of vapor pressure or temperature, which are required to estimate the emissions from the sources included in the cap. *See infra* IV.C.4.a-c.

2. The VOC Emissions from Methanol Loading are Underestimated.

The Facility is designed to load 308,639,340 gal/yr of methanol into railcars, tank trucks or marine vessels. 12/14 Ap., pdf 9-10, 23, 27, 31. The VOC emissions from loading were estimated as 6.66 ton/yr in the Application, calculated from the design loading rate and an uncontrolled VOC emission factor of 2.16 lb per thousand gallons (lb/Mgal), assuming 98% control efficiency using a vapor recovery device.[17] 12/14 Ap. pdf 31. The calculations in the Application significantly underestimate loading VOC emissions. Further, the proposed permit allows much higher VOC emissions.

a. The Loading Emissions Factor is Underestimated.

Loading emissions occur when organic vapors in an "empty" cargo carrier are displaced

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[17] Loading emissions = (2.16 lb/Mgal)(308,639 Mgal/yr)(0.02)/2000 lb/ton = **6.67 ton/yr.**

by liquid being loaded. The loading VOC emissions were estimated from an emission factor in pounds per thousand gallons loaded (lb/Mgal), calculated using an equation from AP-42. 12/14 Ap., pdf 31. The Application asserts loading emissions are based on the worst-case loading operation, a railcar/tank truck, and states several inputs to the calculation are "conservative." Id. However, this is incorrect.

The loading calculations in the Application are not the potential to emit and significantly underestimate loading emissions due to: (1) assuming the wrong mode of operation of the loading system (underestimating VOC emissions a factor of 2.42); (2) assuming 98% control efficiency while the permit is based on 90% (underestimating VOC emissions by a factor of 5); and (3) calculating emissions from an annual average rather than the maximum (underestimating VOC emissions by a factor of 3.5). When all of these underestimates are cured, the VOC loading emissions increase from 6.66 ton/yr to 282 ton/yr. Thus, the potential to emit VOCs from loading alone are sufficient to render the Facility a major source.

The loading emissions factor was calculated using a saturation factor (S) based on submerged loading with dedicated normal service (S factor = 0.6). However, the proposed permit does not require any particular mode of operation. Other modes of operation are feasible, including submerged loading with dedicated vapor balance service (S = 1.00) and splash loading with dedicated normal service (S = 1.45). AP-42, Table 5.2-1. As the permit does not specify the mode of operation of the loading rack, the potential to emit must be based on the worst case, which is splash loading (S = 1.45). As the loading emission factor in lb/Mgal is directly related to the S factor, the Application underestimated the potential to emit VOCs from loading by a factor of 2.4 (1.45/0.6 = 2.42). Using the correct S factor increases the loading VOC emission factor from 2.16 lb/Mgal to 5.23 lb/Mgal (2.16 x 2.42 =5.23). This revision alone increases

VOC emissions from loading from 6.66 ton/yr to 34.8 ton/yr. This change is sufficient to increase the Facility potential to emit VOCs from 80.49 ton/yr to 109 ton/yr.[18]

LDEQ's response to comments asserts it is not necessary to specify a mode of operation for the loading system because Condition 119 requires an organic monitoring device. LDEQ RTC Comment 28. This requirement is in Condition 122, not Condition 119. While Condition 122 does require that such a device to be installed, it does not require that it be used to determine VOC emissions from truck and railcar loading operations to demonstrate compliance with emission rates nor to confirm that the source is minor for VOC emissions.

b. The Maximum Emission Rate was Not Used to Calculate Loading Potential to Emit.

The loading VOC emission calculations report average and maximum hourly controlled emission rates for loading of 1.52 lb/hr and 5.32 lb/hr, respectively. 12/14 Ap., pdf 31. However, the calculation of the potential to emit, in tons per year, is based only on the average emission rate.[19] The potential to emit must be used to determine if a source is major. The potential to emit should be calculated from the maximum emission rate, unless otherwise limited, or unless it is not feasible to operate continuously at that rate, based on facility design.

There is nothing in the proposed permit that would prohibit continuously loading at the maximum VOC emission rate. This would result in controlled VOC emissions of 23.3 ton/yr, assuming 98% control,[20] and 116.5 ton/yr, assuming 90% control.[21] In either case, the increase in VOC emission during loading, if emissions are calculated using the maximum VOC emission

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[18] Revised potential to emit VOCs, assuming splash loading (S=1.45): 80.49 – 6.66 + 34.8 = **108.63 ton/yr**.

[19] The potential to emit VOC emissions during loading: 1.52 lb/hr x 8760 hr/yr/2000 lb/ton = 6.66 ton/yr.

[20] Loading VOC emissions based on maximum controlled emission rate of 5.32 lb/hr: (5.32 lb/hr)(8760 hr/yr)/2000 lb/ton = **23.30 ton/yr.**

[21] Loading VOC emissions based on maximum controlled emission rate of 5.32 lb/hr and 90% control: (5.32 lb/hr)(0.1/0.02)(8760 hr/yr)/2000 lb/ton = **116.51 ton/yr.**

rate of 5.32 lb/hr, rather than the average rate of 1.52 lb/hr, is sufficient to result in total Facility emissions greater than 100 ton/yr. The maximum VOC emissions, absent an enforceable limit to the contrary, from loading would be 103 ton/yr,[22] assuming 98% VOC control and 196.8 ton/yr, assuming 90% VOC control.[23] Thus, the Facility is major for VOCs.

LDEQ's response to comments asserts that the throughput limit of 308,639,340 gallons restricts VOC emissions from loading to no more than 6.66 ton/yr. RTC Comment 31. This is not correct. The Permit allows barge loading VOC emissions of 0.25 lb/1000 gal and continuous barge loading. Thus, assuming the maximum throughput limit, the VOC emissions could reach [0.25 lb/1000 gal x 308,639,340 gal]/2000 lb/ton = 38.5 ton/yr. This would result in VOC emissions of 38.5 ton/yr, which increases the potential to emit VOCs from 78.39 ton/yr to 110 ton/yr (78.9 - 6.66 + 38.5 = 110.3).

c. The Disconnect Emissions are not included in the Emission Calculations.

The unloading rack is individually connected to each rail car, tank car, or marine with couplers. When the loading rack is attached and disconnected, some of the methanol within the coupler spills to the ground and evaporates, releasing VOCs. These emissions were not included in the emission calculations. They should be estimated, included in the VOC potential to emit, and limited in the permit. The Facility description should also explain how these drips will be collected and disposed.

As to disconnect emissions, the response asserts that newly added conditions require special fittings and other provisions, added in Conditions 135 and 165 (incorrectly identified as 132 and 162 in the RTC, p. 28) to minimize these emissions. However, these conditions are

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[22] Facility potential to emit, based on maximum hourly emission rate of 5.32 lb/hr and 98% control: 86.98 – 6.66 + 23.30 = **103.6 ton/yr**.

[23] Facility potential to emit, based on maximum hourly emission rate of 5.32 lb/hr and 90% control: 86.98 – 6.66 + 116.51 = **196.8 ton/yr**.

commonly implemented at rail and barge loading terminals. While they reduce drip VOC emissions, they do not eliminate them and the controlled drip emissions are not de minimus. VOC emissions from spills during loading are routinely calculated and included in emission inventories, especially when asserting a source is minor. *See* EPA NOV for Bakersfield Crude Terminal, Ex. F and supporting files, Ex. G.

3. The Maximum VOC Emission Rate is Not Used to Calculate Auxiliary Boiler and SMR Potential to Emit.

The emission calculations for the auxiliary boiler and SMR report both average and maximum hourly emission rates. However, the calculations of the VOC potential to emit, in tons per year, are based only on the average emission rate and excludes all operation at the maximum VOC emission rate.

The potential to emit must be used to determine if a source is major. The potential to emit should be calculated from the maximum emission rate, unless otherwise limited by enforceable emission limits or facility design. As the proposed permit does not require any testing for VOC emissions from either the SMR (source EQT 0001, Conditions 1-41, requiring testing only for CO, PM, NOx) or the auxiliary boiler (source EQT 0002, Conditions 42-80, requiring testing only for CO, PM, NOx), the reported VOC emissions from these emission units are per se unenforceable.

There is nothing in the proposed permit that would prohibit the major combustion sources, the SMR and the auxiliary boiler, from operating at their maximum emission rate continuously. The maximum VOC emissions, absent an enforceable limit to the contrary, from the SMR would be 32.6 ton/yr.[24] The maximum VOC emissions, absent an enforceable limit to

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[24] Maximum annual VOC emissions from the SMR: (7.44 lb/hr)(8,760 hr/yr)/2000 lb/ton = **32.6 ton/yr**.

the contrary, from the auxiliary boiler, would be 20.7 ton/yr.[25]

In response to this issue, LDEQ added a requirement that VOC emissions from the SMR be measured in a single performance test within 180 days of startup. RTC Comment 34 and Permit, Condition 39. A single stack test over the life of the facility is not adequate to demonstrate continuous compliance with the average emission factor used to estimate VOC emissions to classify the source as minor. No VOC testing was added for the auxiliary boiler. Thus, LDEQ did not adequately respond to this issue. The VOC emissions estimated for the auxiliary boiler and SMR remain unenforceable and cannot be relied on to classify the source as minor for PSD review.

4. The VOC Emissions from the Tanks are significantly underestimated.

The Facility includes one crude methanol tank and five methanol product tanks, each with a capacity of 8 million gallons. 10/14 Ap., p. 2-3. The VOC emissions from these tanks were estimated using the U.S. EPA program, TANKS 4.09d, which is based on equations in AP-42. The VOC emissions from these tanks are significantly underestimated.

The key input parameter that determines tank VOC emissions is the vapor pressure of the material stored in the tank. Vapor pressure is a measure of the volatility of the material. The higher the volatility, the higher the VOC emissions. The vapor pressure, in turn, depends on the temperature of the liquid in the tank. The higher the temperature, the higher the vapor pressure.

The proposed permit conditions do not contain any limits on vapor pressure (routinely required for tank permits) nor any vapor pressure monitoring, except for Condition 110, discussed below. Thus, compliance is left to the discretion of the Applicant, based on a calculation without any tank-specific input parameters. VOC emissions from these tanks are not

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[25] Maximum annual VOC emissions from the auxiliary boiler: (4.73 lb/hr)(8,760 hr/yr)/2000 lb/ton = **20.7 ton/yr**.

limited by the proposed permit and emissions are thus unenforceable. A minor source must contain enforceable limits to ensure they remain below the major source threshold.

a. Emissions from Crude Methanol Tank are Inaccurate.

Crude methanol is generated in the methanol synthesis process, sent to the crude methanol tank for temporary storage, and sent on to purification, where it is converted into pure methanol. The crude methanol contains about 18% water along with other impurities and enters the crude methanol tank at elevated temperatures, reported as 149 F.

The initial Application estimated VOC emissions from this tank of 9.32 ton/yr. 10/14 Ap., TANKS 4.0 Rpt., p. 3. The VOC emissions from this tank were estimated assuming a vapor pressure of 14.7175 psi. 12/14 Ap., pdf 168. This vapor pressure is consistent with methanol stored at 149 F, based on my calculations using the Antoine equation.[26]

LDEQ commented that a tank with such a high vapor pressure should be equipped with a closed vent system and a control device per 63.119(a)(2) and 2103.E & F. 12/14 Ap., Question 6, pdf 2. The Applicant responded by stating "[t]he vapor pressure of the Crude Methanol Tank has been revised to 10.9 psia. Therefore, a closed vent system and control device [] are not required for this tank." Id. The revised VOC emissions for this lower vapor pressure are 3.19 ton/yr. 12/14 Ap., pdf 27-29. These calculations show that the Applicant changed the vapor pressure without changing the storage temperature. The storage temperature corresponding to a vapor pressure of 10.9 psia is 135 F.[27]

It is physically impossible to store methanol at 149 F with a vapor pressure of 10.9 psia. A decline in vapor pressure requires a decline in storage temperature which requires a process

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[26] John A. Dean, Lange's Handbook of Chemistry, 13th Ed., 1985, pp. 10-28 & 10-46, methanol: A=7.89750; B=1,474.08; C = 229.13, t = 149 F = 65 C. logp = A-(B/t+C) = 7.89750-[1,474.08 /(65+229.13)] = 2.8858 and p = 768.8 mmHg = **14.867 psia.**

[27] John A. Dean, Lange's Handbook of Chemistry, 13th Ed., 1985, pp. 10-28 & 10-46. t = (B/A-logp) – C = [1,474.08/7.8975-log(563.693)] – 229.13 = 57.2962 C = **135 F**.

modification. It is unlikely that the temperature could be reduced without modifying the methanol synthesis process to cool the crude methanol prior to storage and the purification process to handle a cooler stream. The Application is silent on process modifications to facilitate a change in crude methanol temperature. Further, the proposed permit does not set a tank temperature or require any tank temperature monitoring, so temperatures could be much higher than even 149 F. Thus, it appears that the reduction in vapor pressure is a just a cosmetic change to avoid installing proper controls for the high methanol vapors that would be released from the crude methanol tank.

Thus, the emissions from the crude methanol tank, reported in the 10/14 Application, TANKS 4.0 Rpt., p. 3, of 9.32 ton/yr (18,634.46 lb/yr) should be used for this tank, rather than the revised amount of 3.19 ton/yr (6,387 lb/yr). 12/14 Ap., pdf 26.

The permit itself is unenforceable as to both the temperature and vapor pressure of the crude methanol tank. The only tank vapor pressure measurement in the entire proposed permit is Condition 110, which requires that the Reid vapor pressure (RVP) of the crude methanol tank be determined. However, the condition does not establish a vapor pressure limit, specify a testing frequency, or require that it be reported, recorded, retained, or used to estimate VOC emissions. Further, the vapor pressure metric used in the tank calculations is the true vapor pressure (TVP), not the RVP. Condition 110 would be satisfied by a single measurement over the life of the Facility and thus does not serve to limit VOC emissions from the crude methanol tank. The fact that the methanol storage tank is part of the Methanol Transfer and Storage Cap (MTSCAP) is irrelevant as no monitoring is required to confirm compliance with this cap. Thus, emissions from individual members of the cap, such as the crude methanol tank, are also unenforceable.

Finally, the design of the crude methanol storage tank must be modified to conform to

LAC 63.119(a)(2) and 2103.E & F, which requires that the tank be equipped with a closed vent system and control device.

LDEQ responds to this issue by citing to additional information dated April 23, 2015 which is not cited specifically or provided to the public or EPA for review as part of the permit record. RTC Comment 35. This response also asserts that the VOC emission calculations were based on the "highest possible temperature at which methanol can be delivered to the crude methanol tank" (135 F), thus monitoring of vapor pressure and temperature are not warranted. RTC Comment 35. Asserting that any characteristic of the crude methanol is the maximum feasible without any support whatsoever is not an adequate basis to support a determination that a source is not major for purposes of PSD review. It is easy to imagine, for example, that process upsets could result in higher temperatures. Further, it is likely that methanol vapors will be present in the crude methanol that will be instantly released, i.e., flashed, when transferred to the tank, regardless of the transfer temperature. These emissions were not considered in the tank calculations. The Permit must be modified to specify a maximum crude methanol storage temperature and vapor pressure and to require periodic monitoring of both temperature and vapor pressure. *See* EPA NOV for Bakersfield Crude Terminal, Ex. E and supporting files, Ex. F.

b. Product Methanol Storage Tanks

The Facility includes five 8 million gallon internal floating roof product methanol storage tanks. The methanol is stored at a temperature of 104 F. VOC emissions were calculated as 2,417.26 lb/hr or 1.21 ton/yr, assuming a vapor pressure of 5.0837 psia. 12/14 Ap., pdf 22-23. Thus, emissions from these five tanks total 6.04 ton/yr, as calculated in the Application.

However, the proposed permit does not contain any limit on either the storage temperature or the vapor pressure of methanol in these tanks. It is easy to imagine that on a hot summer day, the storage temperature could be higher than 104 F. Further, it is easy to imagine that process upsets could increase the temperature of stored methanol. Thus, absent enforceable limits, the potential to emit VOC emissions from these tanks is unlimited. The VOC emissions could be, for example, 10% higher. Assuming 10%, the total VOC emissions from these five tanks would increase from 6.0 ton/yr to 6.6 ton/yr.

LDEQ's response states that 104 F "represents the highest possible temperature at which methanol can be delivered to the methanol product tanks" without any support whatsoever. RTC Comment 35. As noted in response to Comment 35, asserting that any characteristic of the crude methanol is the maximum feasible without any support whatsoever or any required monitoring to demonstrate its accuracy is not an adequate basis to support a determination that a source is not major for purposes of PSD review. The Permit must be modified to specify a maximum methanol storage temperature and vapor pressure and to require periodic monitoring of both temperature and vapor pressure. *See* EPA NOV for Bakersfield Crude Terminal, Ex. E and supporting files, Ex. F.

c. The Roof Landing, Degassing, and Cleaning Emissions are Omitted.

VOC emissions from the storage tanks were estimated using EPA's TANKS 4.0.9d model (TANKS). However, this model only estimates rim seal losses, withdrawal losses, deck fitting losses, and deck seam losses. It does not estimate roof landing losses, inspection losses, or flashing losses. Thus, it underestimated tank VOC emissions. These emissions should be estimated and added to other tank emissions.

The Facility includes six new internal floating roof tanks. The new tanks could be constructed with a leg-supported or self-supporting roof. The TANKS model input indicates that the roofs are not self-supported.[28] 10/14 Ap., pdf 24, 28. In floating roof tanks with leg-supported roofs, the roof floats on the surface of the liquid inside the tank and reduces evaporative losses during normal operations. However, when the tank is emptied, the roof sits on the legs and is essentially uncontrolled, resulting in high VOC emissions.

In February 2010, the EPA explained that the TANKS model does not include roof landings, and recommended that they be estimated with the equations in EPA's *Compilation of Air Pollutant Emission Factors* ("AP-42"). In other words, the EPA TANKS model estimates evaporative emissions for normal operations only, *i.e.*, it assumes that the floating tank roof is always floating.[29] However, when a tank is emptied to the point that the roof no longer floats on the liquid but lands on deck legs, evaporative losses occur.

> After the floating roof is landed and the liquid level in the tank continues to drop, a vacuum is created which could cause the floating roof to collapse. To prevent damage and to equalize the pressure, a breather vent is actuated. Then, a vapor space is formed between the floating roof and the liquid. The breather vent remains open until the roof is again floated, so whenever the roof is landed, vapor can be lost through this vent.[30]

These losses are called "roof landing losses."

In addition, "degassing and cleaning losses" occur when tanks are drained and degassed for inspection and/or cleaning. These include both roof landing emissions, complete tank degassing, and emissions from cleaning out accumulated sludge. These emissions are essentially uncontrolled tank emissions.[31]

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[28] See, *e.g*. 10/14 Ap., TANKS 4.0 Rpt., pp. 1, 4 (Self Supp. Roof? (y/n) = N).

[29] EPA, TANKS Software Frequent Questions, Updated February 2010; http://www.epa.gov/ttnchie1/faq/tanksfaq.html. ("How can I estimate emissions from roof landing losses in the tanks program? … In November 2006, Section 7.1 of AP42 was updated with subsection 7.1.3.2.2 Roof Landings. The TANKS program has not been updated with these new algorithms for internal floating roof tanks. It is based on the 1997 version of section 7.1.").

[30] EPA, AP-42, Chapter 7.1 Organic Liquid Storage Tanks, November 2006; http://www.epa.gov/ttn/chief/ap42/ch07/final/c07s01.pdf.

[31] See EPA guidance on estimating these emissions at: http://www.epa.gov/ttnchie1/faq/tanksfaq.html#13

The EPA recommends methods to estimate emissions from degassing, cleaning, and roof landing losses.[32] The method for estimating emissions depends on the construction of the tank, *e.g.*, the flatness of the tank bottom and the position of the withdrawal line (the so-called liquid "heel"). Degassing and cleaning and roof landing losses continue until the tank is refilled to a sufficient level to again float the tank roof. Total VOC emissions from floating roof tanks during a roof landing is the sum of standing idle losses and filling losses. They can be estimated using formulas contained in EPA's *Compilation of Air Pollutant Emission Factors* ("AP-42"), Chapter 7.1, Organic Liquid Storage Tanks, Section 7.1.3.2.2. These emissions are routinely included in emission inventories, tank emission potential to emit calculations, and are limited in permits.[33] They are required to be reported, for example, in Texas.[34] They are also included in the emission inventories of crude oil terminals,[35] which have lower VOC emissions than methanol terminals. Tank roof landing emissions are large, typically comprising about 40% of total tank emissions. Thus, revised VOC emissions (as estimated above) from the five methanol storage tanks and one crude methanol tank (8.46+9.32 = 17.78 ton/yr) would be 7.11 ton/yr.[36]

LDEQ's response indicates that it added a condition to the permit requiring Yuhuang to

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[32] "How Can I Estimate Emissions from Degassing and Cleaning Operation During a Tank Turnaround? And How Can I Estimate Emissions from Roof Landing Losses in the TANKS Program:?", Available at: http://www.epa.gov/ttnchie1/faq/tanksfaq.html#13 .

[33] See, *e.g.*, Enbridge, Superior Terminal Enhancement Project Permit Application, October 9, 2012, pp. --, Tables 1-1 and 2-2 and Wisconsin Dept. of Natural Resources, Air Pollution Control Construction Permit No. 12-DCF-205, EI Facility No. 816010580, Enbridge Energy Co., Superior, Wisconsin, May 21, 2013

[34] Memorandum from Dan Eden, Deputy Director, Office of Permitting, Remediation, and Registration; David C. Schanbacher, Chief Engineer; and John Steib, Deputy Director, Office of Compliance and Enforcement, Re: Air Emissions During Tank Floating Roof Landings, December 5, 2006, Available at: http://www.tceq.state.tx.us/assets/public/permitting/air/memos/tank_landing_final.pdf .

[35] See, *e.g.*, Tesoro Savage, Application for Site Certification Agreement, Section 5.1.2.1.4, Available at: http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%20I/EFSEC%202013-01%20-%20Compiled%20PDF%20Volume%20I.pdf; Enbridge, Superior Terminal Enhancement Project, Prevention of Significant Deterioration Permit Application, Enbridge Energy, Limited Partnership, Superior, Wisconsin Terminal, October 2012.

[36] Increase in methanol tanks VOC emissions from roof landing emissions = (8.46+9.32)0.4 = **7.11 ton/yr**.

record the number and duration of roof landings and the number of tank cleanings. RTC Comment 37; Permit Condition 263. However, the Methanol Transfer and Storage Cap, Condition 217, does not require that these emissions be included in determining compliance. Condition 217 allows the use of Tanks 4.09 to determine compliance. This model, as explained in my initial comment, does not include roof landing, degassing, and cleaning emissions. None of the compliance provisions require that these emissions be included in determining compliance.

d. The Non-Routine Tank VOC Emissions are Omitted.

The TANKS model used in the Application to estimate VOC emissions from tanks is based on the equations in AP-42, Section 7.1, Organic Liquid Storage Tanks. The equations in AP-42, used to estimate tank emissions in the Application, do not include non-routine emissions, such as those that occur when tanks are improperly operated, defective (e.g. damaged floating roof rim seals and deck fitting), or in disrepair.[37] These non-routine emissions must be included in the potential to emit. LDEQ claims that it need not count these non-routine emissions because. RTC Comment 38. But LDEQ must count emissions associated with malfunctions to determine the source's potential to emit. In the alternative, LDEQ must place a prohibition on such emissions that is legally and practically enforceable.

V. EPA MUST OBJECT TO THE PERMIT BECAUSE THE TANK DESIGN IS HAZARDOUS AND THERE ARE ADDITIONAL UNCOUNTED FOR EMISSIONS.

According to the TANKS 4.0.9d output in the Application, all of the tanks are internal floating roof tanks. These tanks present significant hazards when used without an inert blanket, which is not required in the proposed permit. Dissolved gases can be flashed off and separated

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[37] EPA, Draft EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems, p. 32, August 2014, Available at: http://www.epa.gov/ttn/chief/consentdecree/draft_report_review.pdf.

from the liquid phase, resulting in unstable roofs, safety issues, and ultimately, higher emissions.

The upper flammability limit of methanol is 36% by volume, much higher than gasoline. Thus, methanol vapors can ignite and burn inside the tank vapor space. Further, during tank filling, methanol vapors are displaced through tank vents, creating potential flammability and toxicity hazards around tank. These hazards are typically controlled by excluding air from methanol tank vapor spaces by inerting or gas blanketing.[38] The Application and the proposed permit are silent on these issues. Further, the crude methanol tank is an even greater concern because, if all of the gases are not removed, the release of the gases under a floating roof could cause the roof to become unstable. Therefore, crude methanol is usually not stored in floating roof tanks, but rather fixed roof tanks vented to a control device.

The recently permitted St. James Methanol Plant, for example, rejected an internal floating roof tank for crude methanol storage due to these risks and instead selected a fixed roof tank with thermal oxidation.[39] This Facility also selected internal floating roof tanks with inert gas blankets for product methanol tanks to address these hazards. St. James 7/13 Ap., § 3.0 BACT Analysis, pp. 43-44, EDMS Doc. ID. 9057147.

LDEQ responded that it "understands that Yuhuang will operate the crude methanol tank and methanol product tanks using nitrogen blankets." RTC Comment 39. An "understanding" is not an enforceable condition. The permit must be modified to require nitrogen blankets.

VI. EPA MUST OBJECT TO THE PERMIT BECAUSE LDEQ FAILED TO ADEQUATELY RESPOND TO EPA'S COMMENTS.

EPA asked LDEQ the following questions:

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[38] Methanol Safe Handling Bulletin, Atmospheric Above Ground Tank Storage of Methanol, Available at: http://www.methanol.org/getattachment/Health-And-Safety/Technical-Bulletins/AtmosphericAboveGroundTankStorageMethanol-%281%29.pdf.aspx;

[39] South Louisiana Methanol, St. James Methanol Plant, St. James, Louisiana, Part 70 Title V/Prevention of Significant Deterioration Air Permit Application, July 2013.

> Please clarify why 40 CFR 60.18 is not an applicable requirement for the source since it would appear that the flare may be· used to control emissions from affected facilities at the site. If the flare is subject to 40 CFR 60.18, then provide the necessary testing, monitoring (including gas flow rates to the flare and BTU value of the gas), recordkeeping, and reporting requirements .to the permit.

EPA Cmmt, 5. LDEQ argues that 40 C.F.R. § 60.18 is not applicable because the flare will not be used to control emissions from distillation operations under 40 C.F.R. § Subpart NNN and reactor processes under 40 C.F.R. § Subpart RRR "during normal operation." RTC Comment 5. However, flares are technology that is appropriate only for emergency or unusual situations; flares should not be used to control emissions during "normal operation." LDEQ argues that as these subparts exempt periods of startup, shutdown, and malfunction when the flares would be used as violations, these subparts do not apply to the flare and thus 40 C.F.R. § 60.18 is not applicable. These subparts admit that the flare is used to control emissions from distillation operations and reactor processes. The declassification of an event as a "violation" under this regulation does not mute the fact that these subparts require the use of a flare to control emissions. Thus, 40 C.F.R. § 60.18 is applicable.

CONCLUSION

For the foregoing reasons, EPA should object to the initial Title V air operating air permit no. 2560-00295-V0 (Title V Permit) issued to Yuhuang Chemical Inc. for the construction and operation of a new methanol manufacturing plant in St. James, Louisiana..

Sincerely yours,

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Comments on

Proposed Title V Air Permit

Yuhuang Chemical Inc. Methanol Plant

St. James, Louisiana

AI Number: 194165
Permit Number: 2560-00295-V0
Activity Number: PER20140001

Prepared for

Sierra Club

and

Louisiana Environmental Action Network

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March 16, 2015

Ex. A

Table of Contents

I. Introduction

The Louisiana Department of Environmental Quality (LDEQ) is proposing to permit the Yuhuang Chemical Inc.'s (Applicant's) Methanol Plant (Project or Facility) as a minor source under the Prevention of Significant Deterioration (PSD) program because emissions of all criteria pollutants are reportedly less than 100 ton/yr. SOB,[1] p. 9. My review of the 10/14 initial Application, EDMS Doc. ID. 9527280 (10/14 Ap.),[2] as amended by the 12/14 Modified Application, EDMS Doc. ID. 9570680 (12/14 Ap.), [3] indicates that the Facility has the potential to emit more than 100 ton/yr of carbon monoxide (CO), nitrogen oxides (NOx), and volatile organic compounds (VOCs). I did not review emission calculations for other pollutants.

The Facility therefore constitutes a "major stationary source" under section 302(j) of the Clean Air Act, 42 U.S.C. § 7602(j), subject to the operating permit requirements of Title V of the Act. Id. §§ 7661(2)(B), 7661a(a); see also 40 C.F.R. §§ 71.2, 71.3(a)(1). The Facility also a constitutes a "major stationary source" under Louisiana's PSD regulations, LAC 33:III.509(B), and thus must meet the state's PSD requirements under LAC 33:III.509(J-R). LAC 33:III.509(A)(2). 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). Further, The proposed initial Part 70 (Title V) air permit should be withdrawn and the Facility should be permitted as a major source under the PSD program. The Title V major source permit must include emission limits and impose best available control technology (BACT) for greenhouse gas emissions (GHG).

II. The Facility is a Major Source of Criteria Pollutants and Requires a Prevention of Significant Deterioration ("PSD") Permit.

The Facility is a major source under the PSD program because the potential to emit NOx, VOCs, and CO each exceed 100 ton/yr.

A. The NOx Emissions Exceed 100 ton/yr.

The Statement of Basis ("SOB") and Application estimated total NOx emissions of 85.45 ton/yr from the following sources (SOB, p. 4; 12/14 Ap., Attach. A):

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[1] LDEQ, Statement of Basis (SOB), YCI Methanol Plant, Yuhuang Chemical Inc., St. James, St. James Parish, Louisiana, Activity No. PER20140001, 2015 (SOB).

[2] Letter from Bliss Higgins, Environ, to Tegan Treadaway, LDEQ, Re: Yuhuang Chemical Inc. Methanol Plant, October 31, 2014, attaching: Application for an Initial Title V Air Permit, Yuhuang Chemical Inc. (YCI) Methanol Plant, Prepared for: Yuhuang Chemical Inc., October 2014 (10/14 Application).

[3] Memorandum from Brian Glover, ENVIRON, to Bryan Johnston, LDEQ, Re: Response to Yuhuang Chemical Inc. Initial Permit Review Questions, December 12, 2014 (12/14 Application).

- SMR: 52.56 ton/yr
- Auxiliary Boiler: 23.08 ton/yr
- Flare: 7.25 ton/yr
- Emergency Generator 2.16 ton/yr
- Firewater Pumps: 0.40 ton/yr

The NOx emissions from the flare, SMR, and auxiliary boiler were underestimated. When the underestimates are corrected, total NOx emissions exceed 100 ton/yr.

1. The Flare NOx Emissions are Underestimated.

The NOx emissions from the flare alone are large enough to classify the Facility as a major source because non-routine flaring emissions exceed 100 ton/yr. The flare system collects and combusts vapors generated during startups and shutdowns (SU/SDs) plus various routine streams. 10/14 Ap., p. 2-3. The NOx emissions from these flaring events were estimated in the Application as 7.25 ton/yr, from the following activities (12/14 Ap., pdf[4] 34-40):

- Once-through nitrogen heating: 0.0274 ton/yr
- Startup/Shutdown Methanol Unit: 4.43 ton/yr
- Methanol Catalyst Reduction: 2.66 ton/yr
- Methanol purge: 0.01 ton/yr
- Flare Pilot: 0.13 ton/yr

a. The Applicant Used the Wrong NOx Emission Factor.

All of these flare emissions (except the pilot) were calculated using the NOx emission factor of 0.068 lb/MMBtu for industrial flares from AP-42, Table 13.5-1. This emission factor is based on very old pilot-scale and laboratory-scale studies and is widely recognized as underestimating NOx emissions from flares. The EPA has proposed to revise this emission factor, pursuant to a Consent Decree,[5] based on reliable test data including recent tests of large-scale, commercial flares.[6] The new flare NOx emission factor is 2.9 lb/MMBtu, supported by

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[4] **All citations to pdf page numbers of the 12/14 Ap. refer to the pdf as downloaded from the EDMS Doc. ID 9570680.**

[5] Consent Decree, Air Alliance Houston, Community In-Power and Development Association, Inc., Louisiana Bucket Brigade and Texas Environmental Justice Advocacy, Air Alliance Houston, et al. v. McCarthy, No. 1:13-cv-00621-KBJ (D.D.C.).

[6] AP-42, Proposed Draft Section 13.5 Industrial Flares, (Redline/Strikeout), August 2014, Table 13.5-2. See references 1, 4-6 and 8 cited at p. 13.5-6, Available at:

recent test data.[7] Using this revised NOx emission factor for startup/shutdown and routine venting increases flare NOx emissions from 7.254 ton/yr to 304 ton/yr.[8]

The proposed permit does not contain any conditions that would limit NOx emissions from the flare in any way. Thus, as the flare NOx emissions alone exceed the major source threshold of 100 ton/yr when estimated with an accurate emission factor, the Facility is a major source and must go through PSD review.

b. The Applicant Excluded the Safety Factor from NOx Potential to Emit.

The 12/14 Application explains that a safety factor was added to annual emissions for the flare to account for the final design case. 12/14 Ap., pdf 2, Question 7. This safety factor was applied to the VOC emissions from the flare but not to other pollutants emitted from the flare, such as NOx, CO and PM10, even though the same calculation procedures and flare operating conditions are applicable.

The VOC emission calculations include a safety factor of 44, which was applied to the average hourly flare VOC emission rate.[9] This safety factor was not applied to NOx emissions from the flare. The NOx emissions from the flare were estimated as 7.87 ton/yr, comprising the sum of emissions from the pilot (0.01 ton/yr); nitrogen heating (0.0011 ton/yr); methanol unit startup (0.0096 ton/yr); methanol catalyst regeneration (0.006 ton/yr); and intermittent purge stream (0.15 ton/yr). 12/14 Ap., pdf 34-40. This works out to an average hourly emission rate of

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http://www.epa.gov/ttn/chief/ap42/ch13/final/dc13s05rlso_8-19-14.pdf. See also docket at: http://www.epa.gov/ttn/chief/consentdecree/Comments_as_of_Dec_22_2014.pdf.

[7] U. S EPA, Draft Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations, August 2014; Flare Efficiency Study, EPA-600/2-83-052, U. S. Environmental Protection Agency, Cincinnati, OH, July 1983; TCEQ 2010 Flare Study Final Report. Texas Commission on Environmental Quality Tracking No. 2008-81. Austin, Texas. The University of Texas at Austin Center for Energy and Environmental Resources. August 2011; Performance Test of a Steam-Assisted Elevated Flare with Passive FTIR-Detroit. Marathon Petroleum Company, LP. Detroit, Michigan. Clean Air Engineering, Inc. November 2010; PFTIR Test of Steam-Assisted Elevated Flares-Port Arthur. Flint Hills Resources Port Arthur, LLC. Port Arthur, Texas. Clean Air Engineering, Inc. June 2011; Passive Fourier Transform Infrared Technology (FTIR) Evaluation of P001 Process Control Device. INEOS ABS (USA) Corporation. Addyston, Ohio. INEOS ABS (USA) Corporation. July 2010.

[8] The revised NOx emissions for all flaring events except pilots, based on a flare NOx emission factor of 2.9 lb/MMBtu: (7.1243 ton/yr)(2.9/0.068) = **303.8 ton/yr.** The total revised flare emissions = 303.8 + 0.13 = **303.9 ton/yr**.

[9] Average hourly VOC emission rate, based on ton/yr (12/14 Ap., pdf 34): (0.01 + 0.02 + 0.15 ton/yr)(2000 lb/ton)/8760 hr/yr = 0.041 lb/hr. The hourly emission rate used to calculate annual emissions was 1.80 lb/hr, viz., (1.80 lb/hr)(8760 hr/yr)/2000 lb/ton = 7.88 ton/yr. The 12/14 Ap. at pdf 34 reports 7.87 ton/yr total VOC emissions from the flare. Thus, the safety factor incorporated in the flare VOC emissions calculations is: 1.80 lb/hr/0.041 lb/hr = **43.9**.

1.66 lb/hr, which was used to calculate the potential to emit NOx from the flare of 7.25 ton/yr.[10] If the same safety factor is used to estimate NOx emissions as was used for VOCs (44), NOx emissions from the flare increase from 7.25 ton/yr to 319 ton/yr.[11] Thus, as the flare NOx emissions alone exceed the major source threshold of 100 ton/yr, the Facility is a major source and must go through PSD review.

c. The flare emissions exclude emissions from upsets.

The flare emissions exclude emissions from upsets. The description of once-through nitrogen heating, start-up of the methanol unit, and methanol catalyst reduction states that "[e]missions from upsets are not included in this emissions estimate." 12/14 Ap., pdf 36. Upset emissions must be included in the potential to emit calculation. The Application does not estimate these emissions, but it does report a maximum hourly NOx emission rate of 184.46 lb/hr. 12/14 Ap., pdf 34. If there were 1,084 hours of upset conditions at this maximum emission rate in any given year, NOx emissions from upsets alone would exceed 100 ton/yr. Further, the proposed permit does not require any monitoring or reporting of flare upset events.

B. The Carbon Monoxide Emissions Exceed 100 ton/yr.

The SOB assumes total CO emissions of 88.30 ton/yr. SOB, p. 4. These emissions arise from the following sources (12/14 Ap., pdf 5):

- Steam Methane Reformer: 34.78 ton/yr
- Auxiliary Boiler: 49.67 ton/yr
- Flare: 2.34 ton/yr
- Emergency Generator: 1.17 ton/yr
- Fire Water Pumps: 0.14 ton/yr

The CO emissions from the SMR, auxiliary boiler and flare are underestimated. Further, the conditions in the proposed permit are inadequate to assure that the assumed CO emissions in the potential to emit calculation would be achieved. Some of the more egregious underestimates are discussed below.

Carbon monoxide emissions from fired sources are estimated by multiplying the concentration of CO in the gas stream, typically expressed in parts per million by volume (ppmv) or pounds per million standard cubic feet of gas (lb/MMscf), by the design firing rate in millions

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[10] Annual NOx emissions from flaring = (1.66 lb/yr)(8760 hr/yr)/2000 lb/ton = **7.27 ton/yr**.

[11] NOx emissions, assuming VOC safety factor of 44: (7.25 ton/yr)(44) = **319 ton/yr**.

of British thermal units per hour (MMBtu/hr) and converting units to arrive at pounds per hour (lb/hr) and tons per year (ton/yr).

1. The CO Emissions from the Auxiliary Boiler are Underestimated.

The auxiliary boiler is the major source of CO emissions, contributing 49.67 ton/yr or 56% of the total CO. The auxiliary boiler CO emissions were calculated assuming natural gas combustion in a boiler, emitting 30 ppmv dry basis of CO, adjusted to 3% O_2. 10/14 Ap., Auxiliary Boiler Emissions Calc. The Application does not provide any basis for selecting this CO concentration to estimate CO emissions from the auxiliary boiler. It is much lower than CO emissions from comparable boilers.

The Application estimated emissions of all other criteria pollutants (PM, PM10, PM2.5, VOC, and SO2) from the auxiliary boiler using emission factors from EPA's "Compilation of Air Pollutant Emission Factors, Volume 1" (AP-42), Table 1.4-2. 10/14 Ap., Auxiliary Boiler Emissions Calc. This section of AP-42 contains standard EPA emission factors for combustion of natural gas in boilers without add-on pollution control. These AP-42 factors were not used for NOx because it is controlled by SCR, an add-on pollution control system. These emission factors are used to estimate emissions from natural gas fired boilers, in the absence of advanced pollution control systems (SCR, oxidation catalysts) or vendor guarantees, supported by enforceable permit limits.

The AP-42 emission factor for CO for natural gas fired boilers is 84 lb/10^6 scf. AP-42, Table 1.4-1. This corresponds to about 100 ppm dry basis at 3% O2, which is over a factor of three higher than assumed in the Application's CO emission calculation for the auxiliary boiler. The Application contains no justification for lowering the standard boiler CO emission factor from 100 ppm to 30 ppm.

Further, the proposed permit does not contain sufficient monitoring to confirm that this anomalously low CO limit is achieved in practice. The proposed permit only requires an initial stack test and subsequent tests every 5 years (Permit Condition 78). A stack test typically last three hours and is conducted under ideal operating conditions, generally after the source is tuned up, which would minimize CO emissions compared to routine operation. A three hour optimal snap shot every 5 years is not adequate to assure the CO emissions remain below the 100 ton/yr major source threshold and comply with the auxiliary boiler CO emission rates.

The CO emissions from the auxiliary boiler when estimated using the standard EPA emission factor for natural gas combustion in boilers, consistent with the factors chosen in the Application for other criteria pollutants, are over three times higher than disclosed in the Application (100/30 = 3.3).

The revised CO emissions from the auxiliary boiler are thus 166 ton/yr.[12] Therefore, the CO emissions from the auxiliary boiler alone are high enough to classify the Facility as a major source for purposes of PSD review. If the Applicant wishes to base the CO emissions on 30 ppm, the proposed permit must be modified to require the use of an oxidation catalyst to control CO emissions and a CO CEMS must be required to continuously measure CO to demonstrate compliance.

2. The CO Emissions from the Steam Methane Reformer are Underestimated.

The steam methane reformer (SMR) is the second largest source of CO emissions, contributing 34.78 ton/yr or 39% of the total CO. The SMR CO emissions were calculated assuming natural gas combustion in a boiler, emitting 10 ppmv CO dry basis, adjusted to 3% O2. 10/14 Ap., Steam Methane Reformer Emission Calc. The Application states this is based on information provided by Air Liquide, but the cited document is not in the record, and thus cannot be reviewed or verified. This is a very low CO concentration for natural gas combustion, as discussed for the auxiliary boiler.

The Application estimated emissions of other criteria pollutants (PM, PM10, PM2.5, VOC, and SO2) from the SMR using AP-42 emission factors for natural gas combustion in boilers, as previously discussed for the auxiliary boiler. AP-42, Table 1.4-2. These AP-42 factors were not used for NOx because it is controlled by SCR. The AP-42 emission factor for CO from natural gas fired boilers is 84 lb/10^6 scf. AP-42, Table 1.4-1. This corresponds to about 100 ppm dry basis at 3% O_2, which is about a factor of ten higher than assumed in the Application's CO emission calculations for the SMR.

An SMR can be operated at lower CO concentrations than a conventional natural gas fired boiler. However, this requires operation below the CO breakpoint, or at O_2 levels above the knee of the CO-O_2 curve.[13] The Application does not discuss the effect of oxygen level and temperature on CO emissions from the SMR and does not recommend any conditions to assure the very low CO concentration assumed in the emission calculations is achieved in practice.

Further, the proposed permit does not contain sufficient monitoring to confirm that this anomalously low CO limit is achieved in practice. It only requires an initial stack test and subsequent tests every 5 years (Permit Condition 38). A stack test typically lasts only three hours and is conducted under optimal operating conditions, generally after tuning. A three hour snap shot every 5 years under ideal operating conditions is not adequate to assure continuous

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[12] Revised CO emissions from auxiliary boiler, using AP-42 CO emission factor: 49.67 ton/yr x 3.3 = **165.6 ton/yr**.

[13] Kunz, R.G.; Smith, D.D.; Adamo, E.M. "Predict NOx from Gas-Fired Furnaces" Hydrocarbon Processing Nov. 1996, 75(11), 65-79.

compliance with a CO emission limit, especially one that is much lower than typically assumed for similar sources and which is known to vary significantly depending upon operating conditions. Thus, the proposed permit does not assure total Facility CO emissions remain below the 100 ton/yr major source threshold.

The CO emissions from the SMR , when estimated using the standard EPA emission factor for natural gas combustion in boilers, consistent with the factors chosen in the Application for other criteria pollutants, is ten times higher than disclosed in the Application (100/10 = 10).

The revised CO emissions from the SMR, using the standard AP-42 emission factor of 100 ppm, are 348 ton/yr.[14] Thus, potential CO emissions from the SMR alone are high enough to classify the Facility as a major source for purposes of PSD review. If the Applicant wishes to base the CO emissions on 10 ppm, the proposed permit must be modified to specify temperature and oxygen operating ranges, require a CO CEMS, and continuously monitor CO, temperature, and oxygen to assure the CO emission limits are satisfied.

3. The Maximum Emission Rate is Not Used to Calculate Potential to Emit.

The emission calculations report average and maximum hourly emission rates. However, the calculation of the potential to emit, in tons per year, is based only on the average emission rate and excludes SSM emissions and all operation at the maximum emission rate. The potential to emit must be used to determine if a source is major. The potential to emit should be calculated from the maximum emission rate, unless otherwise limited by enforceable emission limits or facility design.

There is nothing in the proposed permit that would prohibit the major combustion sources, the SMR, auxiliary boiler or flare, from operating at their maximum emission rate continuously. This would result in the SMR, auxiliary boiler, and flare individually exceeding 100 ton/yr CO. The maximum CO emissions, absent an enforceable limit to the contrary, from the SMR would be 348 ton/yr;[15] from the auxiliary boiler, 166 ton/yr;[16] and from the flare, 231 ton/yr.[17] Thus, the Facility is major for CO.

Further, these sources need not operate full time at the maximum rate to individually emit 100 ton/yr. For example, if the SMR operated only 20% of the time or 1,826 hours at the maximum rate of 79.4 lb/hr and the balance of the time at the average CO emission rate of 7.94 lb/hr, the total CO emissions would be 100 ton/yr.

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[14] Revised CO emissions from SMR, using AP-42 CO emission factor: 34.78 x 10 = **347.8 ton/yr**.

[15] Maximum annual CO emissions from the SMR: (79.4 lb/hr)(8,760 hr/yr)/2000 lb/ton = **347.8 ton/yr**.

[16] Maximum annual CO emissions from the auxiliary boiler: (37.8 lb/hr)(8,760 hr/yr)/2000 lb/ton = **165.6 ton/yr**.

[17] Maximum annual CO emissions from the flare: (52.82 lb/hr)(8,760 hr/yr)/2000 lb/ton = **231.35 ton/yr**.

4. The Flare CO Emissions are Underestimated.

The CO emissions from the flare were underestimated by failing to include the designs safety factor and by failing to include CO emissions from upsets.

a. The Flare Safety Factor were Excluded from CO Potential to Emit.

The 12/14 Application explains that a safety factor was added to annual emissions for the flare to account for the final design case. 12/14 Ap., pdf 2, Question 7. This safety factor was applied to the VOC emissions but not other pollutants emitted from the flare, such as NOx, CO, and PM10, even though the same calculation procedures, flare design basis, and flare operating conditions are applicable.

The VOC emission calculations include a safety factor of 44, which was applied to the average hourly flare VOC emission rate.[18] A safety factor was not applied to CO emissions from the flare. The CO emissions from the flare were estimated as 2.34 ton/yr, comprising the sum of emissions from the pilot (0.13 ton/yr); startup/shutdown (2.18 ton/yr); and purge (0.03 ton/yr). 12/14 Ap., pdf 34. This works out to an average hourly emission rate of 0.53 lb/hr,[19] which was used to calculate the potential to emit CO from the flare of 2.34 ton/yr.[20] If the same safety factor is used to estimate CO emissions as was used for VOCs (12/14 Ap., pdf 44), CO emissions from the flare increase from 2.34 ton/yr to 103 ton/yr.[21] Thus, as the flare CO emissions alone exceed the major source threshold of 100 ton/yr when the safety factor is included in the calculations, the Facility is a major source and must go through PSD review.

b. The CO Emissions were excluded from Flare Upsets.

The flare emissions exclude emissions from upsets. The description of once-through nitrogen heating, start-up of the methanol unit, and methanol catalyst reduction states that "[e]missions from upsets are not included in this emissions estimate." 12/14 Ap., pdf 36. Upset emissions must be included in the potential to emit calculation. The Application does not estimate these emissions, but it does report a maximum hourly CO emission rate of 52.82 lb/hr. 12/14 Ap., pdf 34. At this rate, if there were 3,786 hours of upset conditions at this maximum emission rate in any given year, CO emissions from upsets alone would exceed 100 ton/yr. The proposed permit does not require any monitoring or reporting of flare upset events.

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[18] Average hourly VOC emission rate, based on ton/yr (12/14 Ap., pdf 34): (0.01 + 0.02 + 0.15 ton/yr)(2000 lb/ton)/8760 hr/yr = 0.041 lb/hr. The hourly emission rate used to calculate annual emissions was 1.80 lb/hr, viz., (1.80 lb/hr)(8760 hr/yr)/2000 lb/ton = 7.88 ton/yr. The 12/14 Ap. at pdf 34 reports 7.87 ton/yr total VOC emissions from the flare. Thus, the safety factor incorporated in the flare VOC emissions calculations is: 1.80 lb/hr/0.041 lb/hr = **43.9**.

[19] Average hourly CO emission rate: (0.13 + 2.18 + 0.03 ton/yr)(2000 lb/ton)/8760 hr/yr = **0.53 lb/hr**.

[20] Potential to emit CO from the flare = (0.53 lb/hr)(8760 hr/yr)/2000 lb/ton = **2.32 ton/yr.**

[21] CO emissions, assuming VOC safety factor of 44: (2.34 ton/yr)(44) = **103 ton/yr**.

5. The Fugitive CO Emissions were Excluded from the Emission Calculations.

Fugitive emissions are equipment leaks from pumps, compressors, valves, and connectors. The Steam Methane Reformer (SMR) uses a catalyst in the presence of steam to reform methane from natural gas into a raw syngas stream composed primarily of hydrogen, CO, and carbon dioxide. 10/14 Ap., p. 1-1 The CO concentrations in this stream are very high. Other streams in the proposed Facility will also contain very high CO concentrations.[22] Any fugitive components that handle these high CO streams – compressors, pumps, valves, flanges – will emit large amounts of CO. This source of CO was omitted from the emission calculations.

III. The VOC Emissions Exceed 100 tons/yr .

The SOB reported the potential to emit for VOC emissions of 80.49 tons/yr (SOB, pdf 4) from the sources listed in Table 1. 12/14 Ap., pdf 5. The Application significantly underestimated the potential to emit VOCs. The revised VOC emissions, based on my review of the record, are summarized in Table 1. My calculations, discussed below, indicate that the Facility has the potential to emit more than 100 ton/yr of VOCs and is thus a major source.

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[22] See, e.g., K. Aasberg-Petersen, C.S. Nielsen, I. Dybkjaer, and J. Perregaard, Large Scale Methanol Production from Natural Gas, Feb. 2014, Available at: http://www.topsoe.com/file/large-scale-methanol-production-natural-gas.

Table 1:
VOC Emissions (ton/yr)

	12/14/ Ap.	Revised
5 methanol product tanks	6.04	8.46
1 crude methanol tank	3.19	9.32
Tank roof landing losses	-	7.1
Methanol loading	6.66	23.3-282
Fugitives	3.98	
SMR	28.34	32.6
Auxiliary Boiler	12.48	20.7
Flare	0.17	>0.17
Emergency Generator	0.50	
Firewater Pump #1	0.07	
Firewater Pump #2	0.07	
Cooling Tower	8.65	
Wastewater Treatment	3.00	
TOTAL	**80.49**	**117.9 – 376.6**

1. The Methanol Transfer and Storage Cap (MTSCAP) is Not Enforceable.

The emissions from six storage tanks and methanol truck, railcar, and marine loading operations are lumped together in a cap, a single annual emission limit of 15.9 ton/yr of VOCs that covers all of these processes. SOB, p. 11; 12/14 Ap., Attach. E., pdf 22. This cap is referred to as the Methanol Transfer and Storage Cap (MTSCAP), ID GRP 0001 in the proposed permit or simply "cap" in these comments. Permit, pdf 27.

The proposed permit limits emissions from the cap to 15.90 tons per 12-consecutive month period. Permit, Condition 214, pdf 52. This condition only requires: "Record VOC/methanol emissions each month and total VOC/methanol emissions for the preceding twelve months." Id. The permit does not explain how the emissions would be determined for purposes of recording. Presumably, they would be calculated, using the AP-42 equation used in the Application, but the proposed permit fails to specify any calculation method. Calculations require inputs, actual measurements of factors used in the calculation, such as vapor pressure and temperature. The permit also does not impose any conditions, such as throughputs or vapor pressure and temperature limits. The permit also does not required any monitoring of calculation inputs to assure calculated VOC emissions would be met nor identify the method(s) that must be used to calculate emissions.

A recent report by EPA, for example, explains that the equations in AP-42, used to estimate emissions from all sources in the cap, "can inaccurately estimate emissions when default values are used inappropriately or when site-specific inputs are not entered into the equations…. Emissions from tanks that are improperly operated, defective (e.g. damaged floating roof rim seals and deck fitting), or in disrepair cannot be accurately estimated using these methods."[23] The proposed permit does not require that calculations used to determine compliance (and that were used to estimate potential to emit) account for site-specific conditions and unusual emissions that occur as a result of process upsets, malfunctions, startups and shutdowns.

VOC emissions depend on the vapor pressure of the material that is stored and transferred. The vapor pressure, in turn, depends on material temperature. See, for example, 10/14 Ap., Appx. A. Thus, the permit must include limits on vapor pressure and temperature for storage tanks and loading operations to ensure enforceability. The permit must also require that the vapor pressure and temperature be monitored periodically. Finally, the method to be used to calculate emissions, once the inputs are measured, must be specified.

The permit is missing all three of these essential ingredients to assure enforceability. This is particularly critical here as the Facility is being permitted as a minor source. This permit does not set any limits on calculation inputs or require monitoring of these inputs to assure that the Facility operates as a minor source. The permit, as drafted, would allow the Applicant to simply assert an emission level without any obligation to demonstrate the Facility is actually meeting it. As explained below, the Application has significantly underestimated VOC emissions. The revised emissions exceed the major source threshold of 100 ton/yr.

2. The VOC Emissions from Methanol Loading are Underestimated.

The Facility is designed to load 308,639,340 gal/yr of methanol into railcars, tank trucks or marine vessels. 12/14 Ap., pdf 9-10, 23, 27, 31. The VOC emissions from loading were estimated as 6.66 ton/yr in the Application, calculated from the design loading rate and an uncontrolled VOC emission factor of 2.16 lb per thousand gallons (lb/Mgal), assuming 98% control efficiency using a vapor recovery device.[24] 12/14 Ap. pdf 31. The calculations in the Application significantly underestimate loading VOC emissions. Further, the proposed permit allows much higher VOC emissions.

a. The Loading Emissions Factor is Underestimated.

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[23] EPA, Draft EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems, p. 32, August 2014, Available at: http://www.epa.gov/ttn/chief/consentdecree/draft_report_review.pdf.

[24] Loading emissions = (2.16 lb/Mgal)(308,639 Mgal/yr)(0.02)/2000 lb/ton = **6.67 ton/yr.**

Loading emissions occur when organic vapors in an "empty" cargo carrier are displaced by liquid being loaded. The loading VOC emissions were estimated from an emission factor in pounds per thousand gallons loaded (lb/Mgal), calculated using an equation from AP-42. 12/14 Ap., pdf 31. The Application asserts loading emissions are based on the worst-case loading operation, a railcar/tank truck, and states several inputs to the calculation are "conservative." Id. However, this is incorrect.

The loading calculations in the Application are not the potential to emit and significantly underestimate loading emissions due to: (1) assuming the wrong mode of operation of the loading system (underestimating VOC emissions a factor of 2.42); (2) assuming 98% control efficiency while the permit is based on 90% (underestimating VOC emissions by a factor of 5); and (3) calculating emissions from an annual average rather than the maximum (underestimating VOC emissions by a factor of 3.5). When all of these underestimates are cured, the VOC loading emissions increase from 6.66 ton/yr to 282 ton/yr. Thus, the potential to emit VOCs from loading alone are sufficient to render the Facility a major source.

The loading emissions factor was calculated using a saturation factor (S) based on submerged loading with dedicated normal service (S factor = 0.6). However, the proposed permit does not require any particular mode of operation. Other modes of operation are feasible, including submerged loading with dedicated vapor balance service (S = 1.00) and splash loading with dedicated normal service (S = 1.45). AP-42, Table 5.2-1. As the permit does not specify the mode of operation of the loading rack, the potential to emit must be based on the worst case, which is splash loading (S = 1.45). As the loading emission factor in lb/Mgal is directly related to the S factor, the Application underestimated the potential to emit VOCs from loading by a factor of 2.4 (1.45/0.6 = 2.42). Using the correct S factor increases the loading VOC emission factor from 2.16 lb/Mgal to 5.23 lb/Mgal (2.16 x 2.42 =5.23). This revision alone increases VOC emissions from loading from 6.66 ton/yr to 34.8 ton/yr. This change is sufficient to increase the Facility potential to emit VOCs from 80.49 ton/yr to 109 ton/yr.[25]

b. *The Vapor Control System Efficiency used to Calculate Emissions is not required by the permit.*

The VOC emissions from loading operations assumed loading vapors would be controlled with a 98% efficient control device. 12/14 Ap., pdf 31, note 5. However, the proposed permit, Condition 159, only requires the use of a 90% efficient vapor control system during marine loading and Condition 132 only requires 90% control efficiency for truck and rail

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[25] Revised potential to emit VOCs, assuming splash loading (S=1.45): 80.49 – 6.66 + 34.8 = **108.63 ton/yr**.

car operations. While Condition 136 requires 98% control to reduce HAP emissions from marine vessel loading, this condition does not apply to truck and railcar loading, nor more generally, to VOCs. The worst-case emissions are based on railcar/tank truck loading. Thus, the potential to emit VOCs from loading operations should be based on 90%, or the permit must be modified to require a 98% efficient control device and testing to demonstrate 98% is achieved in practice for truck and railcar loading operations.

Therefore, the potential to emit VOCs during loading is much higher than assumed in the Application. Using the Applicant's VOC loading emission factor, VOC emissions would increase from 6.66 ton/yr to 33.29 ton/yr during loading.[26] This change alone is high enough to increase the Facility's potential to emit VOC from 80.49 ton/yr to 107 ton/yr.[27] Thus, the Facility is a major source, based on the potential to emit VOCs, when corrected to address the methanol loading vapor recovery control efficiency limits in the proposed permit.

c. The Methanol Loading VOC Emission Factor is Incorrect.

The methanol VOC loading emissions were estimated from an uncontrolled emission factor of 2.16 pounds of VOCs per thousand gallons of methanol loaded (lb/Mgal), assuming 98% control. 12/14 Ap., pdf 31. Thus, the controlled emission factor is 0.043 lb/Mgal.[28] The proposed permit, Condition 159, allows VOC emissions of up to 0.25 lb/1000 gal for barge loading and 0.1 lb/1000 gal for ship loading. The permit would allow 100% of the methanol to be loaded into barges. Thus, the proposed permit allows loading VOC emissions of up to 38.6 ton/yr.[29] The revised potential to emit, assuming the proposed permit limits, is 112 ton/yr for VOCs.[30] Thus, the Facility is a major source, based on the potential to emit VOCs, when corrected to address loading VOC emission limits in the proposed permit.

d. The Maximum Emission Rate was Not Used to Calculate Loading Potential to Emit.

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[26] Potential to emit VOC during loading, assuming 90% control efficiency: (332.94 ton/yr)(1-0.9) = **33.29 ton/yr.**

[27] Revised potential to emit VOC, assuming 90% control efficiency = 80.49 – 6.66 + 33.29 = **107.12 ton/yr.**

[28] Controlled loading emission factor used to estimate loading VOC emissions = (2.16 lb/Mgal)(1-0.98) = **0.043 lb/Mgal**.

[29] Loading VOC emissions allowed by Permit Condition 159: (0.25 lb/Mgal)(308,639 Mgal/yr)/2000 lb/ton = **38.58 ton/yr**.

[30] Revised potential to emit VOC, assuming barge limit in Condition 159: (80.49 – 6.66 + 38.58) = **112.41 ton/yr**.

The loading VOC emission calculations report average and maximum hourly controlled emission rates for loading of 1.52 lb/hr and 5.32 lb/hr, respectively. 12/14 Ap., pdf 31. However, the calculation of the potential to emit, in tons per year, is based only on the average emission rate.[31] The potential to emit must be used to determine if a source is major. The potential to emit should be calculated from the maximum emission rate, unless otherwise limited, or unless it is not feasible to operate continuously at that rate, based on facility design.

There is nothing in the proposed permit that would prohibit continuously loading at the maximum VOC emission rate. This would result in controlled VOC emissions of 23.3 ton/yr, assuming 98% control,[32] and 116.5 ton/yr, assuming 90% control.[33] In either case, the increase in VOC emission during loading, if emissions are calculated using the maximum VOC emission rate of 5.32 lb/hr, rather than the average rate of 1.52 lb/hr, is sufficient to result in total Facility emissions greater than 100 ton/yr. The maximum VOC emissions, absent an enforceable limit to the contrary, from loading would be 103 ton/yr,[34] assuming 98% VOC control and 196.8 ton/yr, assuming 90% VOC control.[35] Thus, the Facility is major for VOCs.

e. The Disconnect Emissions are not included in the Emission Calculations.

The unloading rack is individually connected to each rail car, tank car, or marine with couplers. When the loading rack is attached and disconnected, some of the methanol within the coupler spills to the ground and evaporates, releasing VOCs. These emissions were not included in the emission calculations. They should be estimated, included in the VOC potential to emit, and limited in the permit. The Facility description should also explain how these drips will be collected and disposed.

f. The Permit Limits for Truck and Railcar Loading Emissions are Not Enforceable.

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[31] The potential to emit VOC emissions during loading: 1.52 lb/hr x 8760 hr/yr/2000 lb/ton = 6.66 ton/yr.

[32] Loading VOC emissions based on maximum controlled emission rate of 5.32 lb/hr: (5.32 lb/hr)(8760 hr/yr)/2000 lb/ton = **23.30 ton/yr.**

[33] Loading VOC emissions based on maximum controlled emission rate of 5.32 lb/hr and 90% control: (5.32 lb/hr)(0.1/0.02)(8760 hr/yr)/2000 lb/ton = **116.51 ton/yr.**

[34] Facility potential to emit, based on maximum hourly emission rate of 5.32 lb/hr and 98% control: 86.98 – 6.66 + 23.30 = **103.6 ton/yr**.

[35] Facility potential to emit, based on maximum hourly emission rate of 5.32 lb/hr and 90% control: 86.98 – 6.66 + 116.51 = **196.8 ton/yr**.

The VOC potential to emit for methanol loading (6.66 ton/yr) is based on railcar/tank truck loading, assuming a specific saturation factor, loading temperature, vapor control efficiency, and product throughput. The proposed permit does not specify how compliance with this limit will be demonstrated, e.g., by testing or calculation. If by calculation, the proposed permit does not specify the mode of operation during loading (e.g., limit the saturation factor), set a temperature limit, or limit the amount of material that may be loaded into trucks and railcars. Further, the proposed permit does not require that the vapor recovery system achieve 98% control and does not require testing to determine vapor recovery control efficiency.

In comparison, for marine loading, the proposed permit contains detailed monitoring and recordkeeping requirements (EQT 0016, Conditions 133-162), but nothing comparable for truck and railcar loading operations (EQT 0015, Conditions 133-135). The emissions assumed in the loading emission calculations, which are based on truck/railcar loading, are unenforceable as the proposed permit does not require any monitoring or recordkeeping, except Condition 134, which only requires daily records to be maintained of total VOC (i.e., methanol) throughput.

3. The Maximum VOC Emission Rate is Not Used to Calculate Auxiliary Boiler and SMR Potential to Emit.

The emission calculations for the auxiliary boiler and SMR report both average and maximum hourly emission rates. However, the calculations of the VOC potential to emit, in tons per year, are based only on the average emission rate and excludes all operation at the maximum VOC emission rate.

The potential to emit must be used to determine if a source is major. The potential to emit should be calculated from the maximum emission rate, unless otherwise limited by enforceable emission limits or facility design. As the proposed permit does not require any testing for VOC emissions from either the SMR (source EQT 0001, Conditions 1-41, requiring testing only for CO, PM, NOx) or the auxiliary boiler (source EQT 0002, Conditions 42-80, requiring testing only for CO, PM, NOx), the reported VOC emissions from these emission units are per se unenforceable.

There is nothing in the proposed permit that would prohibit the major combustion sources, the SMR and the auxiliary boiler, from operating at their maximum emission rate continuously. The maximum VOC emissions, absent an enforceable limit to the contrary, from the SMR would be 32.6 ton/yr.[36] The maximum VOC emissions, absent an enforceable limit to the contrary, from the auxiliary boiler, would be 20.7 ton/yr.[37]

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[36] Maximum annual VOC emissions from the SMR: (7.44 lb/hr)(8,760 hr/yr)/2000 lb/ton = **32.6 ton/yr**.

[37] Maximum annual VOC emissions from the auxiliary boiler: (4.73 lb/hr)(8,760 hr/yr)/2000 lb/ton = **20.7 ton/yr**.

4. The VOC Emissions from the Tanks are significantly underestimated.

The Facility includes one crude methanol tank and five methanol product tanks, each with a capacity of 8 million gallons. 10/14 Ap., p. 2-3. The VOC emissions from these tanks were estimated using the U.S. EPA program, TANKS 4.09d, which is based on equations in AP-42. The VOC emissions from these tanks are significantly underestimated.

The key input parameter that determines tank VOC emissions is the vapor pressure of the material stored in the tank. Vapor pressure is a measure of the volatility of the material. The higher the volatility, the higher the VOC emissions. The vapor pressure, in turn, depends on the temperature of the liquid in the tank. The higher the temperature, the higher the vapor pressure.

The proposed permit conditions do not contain any limits on vapor pressure (routinely required for tank permits) nor any vapor pressure monitoring, except for Condition 110, discussed below. Thus, compliance is left to the discretion of the Applicant, based on a calculation without any tank-specific input parameters. VOC emissions from these tanks are not limited by the proposed permit and emissions are thus unenforceable. A minor source must contain enforceable limits to ensure they remain below the major source threshold.

a. Emissions from Crude Methanol Tank are Inaccurate.

Crude methanol is generated in the methanol synthesis process, sent to the crude methanol tank for temporary storage, and sent on to purification, where it is converted into pure methanol. The crude methanol contains about 18% water along with other impurities and enters the crude methanol tank at elevated temperatures, reported as 149 F.

The initial Application estimated VOC emissions from this tank of 9.32 ton/yr. 10/14 Ap., TANKS 4.0 Rpt., p. 3. The VOC emissions from this tank were estimated assuming a vapor pressure of 14.7175 psi. 12/14 Ap., pdf 168. This vapor pressure is consistent with methanol stored at 149 F, based on my calculations using the Antoine equation.[38]

LDEQ commented that a tank with such a high vapor pressure should be equipped with a closed vent system and a control device per 63.119(a)(2) and 2103.E & F. 12/14 Ap., Question 6, pdf 2. The Applicant responded by stating "[t]he vapor pressure of the Crude Methanol Tank has been revised to 10.9 psia. Therefore, a closed vent system and control device [] are not required for this tank." Id. The revised VOC emissions for this lower vapor pressure are 3.19 ton/yr. 12/14 Ap., pdf 27-29. These calculations show that the Applicant changed the vapor

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[38] John A. Dean, Lange's Handbook of Chemistry, 13th Ed., 1985, pp. 10-28 & 10-46, methanol: A=7.89750; B=1,474.08; C = 229.13, t = 149 F = 65 C. logp = A-(B/t+C) = 7.89750-[1,474.08 /(65+229.13)] = 2.8858 and p = 768.8 mmHg = **14.867 psia.**

pressure without changing the storage temperature. The storage temperature corresponding to a vapor pressure of 10.9 psia is 135 F.[39]

It is physically impossible to store methanol at 149 F with a vapor pressure of 10.9 psia. A decline in vapor pressure requires a decline in storage temperature which requires a process modification. It is unlikely that the temperature could be reduced without modifying the methanol synthesis process to cool the crude methanol prior to storage and the purification process to handle a cooler stream. The Application is silent on process modifications to facilitate a change in crude methanol temperature. Further, the proposed permit does not set a tank temperature or require any tank temperature monitoring, so temperatures could be much higher than even 149 F. Thus, it appears that the reduction in vapor pressure is a just a cosmetic change to avoid installing proper controls for the high methanol vapors that would be released from the crude methanol tank.

Thus, the emissions from the crude methanol tank, reported in the 10/14 Application, TANKS 4.0 Rpt., p. 3, of 9.32 ton/yr (18,634.46 lb/yr) should be used for this tank, rather than the revised amount of 3.19 ton/yr (6,387 lb/yr). 12/14 Ap., pdf 26.

The permit itself is unenforceable as to both the temperature and vapor pressure of the crude methanol tank. The only tank vapor pressure measurement in the entire proposed permit is Condition 110, which requires that the Reid vapor pressure (RVP) of the crude methanol tank be determined. However, the condition does not establish a vapor pressure limit, specify a testing frequency, or require that it be reported, recorded, retained, or used to estimate VOC emissions. Further, the vapor pressure metric used in the tank calculations is the true vapor pressure (TVP), not the RVP. Condition 110 would be satisfied by a single measurement over the life of the Facility and thus does not serve to limit VOC emissions from the crude methanol tank. The fact that the methanol storage tank is part of the Methanol Transfer and Storage Cap (MTSCAP) is irrelevant as no monitoring is required to confirm compliance with this cap. Thus, emissions from individual members of the cap, such as the crude methanol tank, are also unenforceable.

Finally, the design of the crude methanol storage tank must be modified to conform to LAC 63.119(a)(2) and 2103.E & F, which requires that the tank be equipped with a closed vent system and control device.

b. Product Methanol Storage Tanks

The Facility includes five 8 million gallon internal floating roof product methanol storage tanks. The methanol is stored at a temperature of 104 F. VOC emissions were calculated as 2,417.26 lb/hr or 1.21 ton/yr, assuming a vapor pressure of 5.0837 psia. 12/14 Ap., pdf 22-23. Thus, emissions from these five tanks total 6.04 ton/yr, as calculated in the Application.

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[39] John A. Dean, Lange's Handbook of Chemistry, 13th Ed., 1985, pp. 10-28 & 10-46. t = (B/A-logp) – C = [1,474.08/7.8975-log(563.693)] – 229.13 = 57.2962 C = **135 F**.

However, the proposed permit does not contain any limit on either the storage temperature or the vapor pressure of methanol in these tanks. It is easy to imagine that on a hot summer day, the storage temperature could be higher than 104 F. Further, it is easy to imagine that process upsets could increase the temperature of stored methanol. Thus, absent enforceable limits, the potential to emit VOC emissions from these tanks is unlimited. The VOC emissions could be, for example, 10% higher. Assuming 10%, the total VOC emissions from these five tanks would increase from 6.0 ton/yr to 6.6 ton/yr.

c. The Roof Landing, Degassing, and Cleaning Emissions are Omitted.

VOC emissions from the storage tanks were estimated using EPA's TANKS 4.0.9d model (TANKS). However, this model only estimates rim seal losses, withdrawal losses, deck fitting losses, and deck seam losses. It does not estimate roof landing losses, inspection losses, or flashing losses. Thus, it underestimated tank VOC emissions. These emissions should be estimated and added to other tank emissions.

The Facility includes six new internal floating roof tanks. The new tanks could be constructed with a leg-supported or self-supporting roof. The TANKS model input indicates that the roofs are not self-supported.[40] 10/14 Ap., pdf 24, 28. In floating roof tanks with leg-supported roofs, the roof floats on the surface of the liquid inside the tank and reduces evaporative losses during normal operations. However, when the tank is emptied, the roof sits on the legs and is essentially uncontrolled, resulting in high VOC emissions.

In February 2010, the EPA explained that the TANKS model does not include roof landings, and recommended that they be estimated with the equations in EPA's *Compilation of Air Pollutant Emission Factors* ("AP-42"). In other words, the EPA TANKS model estimates evaporative emissions for normal operations only, *i.e.*, it assumes that the floating tank roof is always floating.[41] However, when a tank is emptied to the point that the roof no longer floats on the liquid but lands on deck legs, evaporative losses occur.

> After the floating roof is landed and the liquid level in the tank continues to drop, a vacuum is created which could cause the floating roof to collapse. To prevent damage and to equalize the pressure, a breather vent is actuated. Then, a vapor space is formed between the floating roof and the liquid. The breather vent

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[40] See, *e.g*. 10/14 Ap., TANKS 4.0 Rpt., pp. 1, 4 (Self Supp. Roof? (y/n) = N).

[41] EPA, TANKS Software Frequent Questions, Updated February 2010; http://www.epa.gov/ttnchie1/faq/tanksfaq.html. ("How can I estimate emissions from roof landing losses in the tanks program? … In November 2006, Section 7.1 of AP42 was updated with subsection 7.1.3.2.2 Roof Landings. The TANKS program has not been updated with these new algorithms for internal floating roof tanks. It is based on the 1997 version of section 7.1.").

> remains open until the roof is again floated, so whenever the roof is landed, vapor can be lost through this vent.[42]

These losses are called "roof landing losses."

In addition, "degassing and cleaning losses" occur when tanks are drained and degassed for inspection and/or cleaning. These include both roof landing emissions, complete tank degassing, and emissions from cleaning out accumulated sludge. These emissions are essentially uncontrolled tank emissions.[43]

The EPA recommends methods to estimate emissions from degassing, cleaning, and roof landing losses.[44] The method for estimating emissions depends on the construction of the tank, *e.g.*, the flatness of the tank bottom and the position of the withdrawal line (the so-called liquid "heel"). Degassing and cleaning and roof landing losses continue until the tank is refilled to a sufficient level to again float the tank roof. Total VOC emissions from floating roof tanks during a roof landing is the sum of standing idle losses and filling losses. They can be estimated using formulas contained in EPA's *Compilation of Air Pollutant Emission Factors* ("AP-42"), Chapter 7.1, Organic Liquid Storage Tanks, Section 7.1.3.2.2. These emissions are routinely included in emission inventories, tank emission potential to emit calculations, and are limited in permits.[45] They are required to be reported, for example, in Texas.[46] They are also included in the emission inventories of crude oil terminals,[47] which have lower VOC emissions than methanol terminals. Tank roof landing emissions are large, typically comprising about 40% of total tank emissions.

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[42] EPA, AP-42, Chapter 7.1 Organic Liquid Storage Tanks, November 2006; http://www.epa.gov/ttn/chief/ap42/ch07/final/c07s01.pdf.

[43] See EPA guidance on estimating these emissions at: http://www.epa.gov/ttnchie1/faq/tanksfaq.html#13 .

[44] "How Can I Estimate Emissions from Degassing and Cleaning Operation During a Tank Turnaround? And How Can I Estimate Emissions from Roof Landing Losses in the TANKS Program:?", Available at: http://www.epa.gov/ttnchie1/faq/tanksfaq.html#13 .

[45] See, *e.g.*, Enbridge, Superior Terminal Enhancement Project Permit Application, October 9, 2012, pp. --, Tables 1-1 and 2-2 and Wisconsin Dept. of Natural Resources, Air Pollution Control Construction Permit No. 12-DCF-205, EI Facility No. 816010580, Enbridge Energy Co., Superior, Wisconsin, May 21, 2013

[46] Memorandum from Dan Eden, Deputy Director, Office of Permitting, Remediation, and Registration; David C. Schanbacher, Chief Engineer; and John Steib, Deputy Director, Office of Compliance and Enforcement, Re: Air Emissions During Tank Floating Roof Landings, December 5, 2006, Available at: http://www.tceq.state.tx.us/assets/public/permitting/air/memos/tank_landing_final.pdf .

[47] See, *e.g.*, Tesoro Savage, Application for Site Certification Agreement, Section 5.1.2.1.4, Available at: http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%20I/EFSEC%202013-01%20-%20Compiled%20PDF%20Volume%20I.pdf; Enbridge, Superior Terminal Enhancement Project, Prevention of Significant Deterioration Permit Application, Enbridge Energy, Limited Partnership, Superior, Wisconsin Terminal, October 2012.

Thus, revised VOC emissions (as estimated above) from the five methanol storage tanks and one crude methanol tank (8.46+9.32 = 17.78 ton/yr) would be 7.11 ton/yr.[48]

d. *The Non-Routine Tank VOC Emissions are Omitted.*

The TANKS model used in the Application to estimate VOC emissions from tanks is based on the equations in AP-42, Section 7.1, Organic Liquid Storage Tanks. The equations in AP-42, used to estimate tank emissions in the Application, do not include non-routine emissions, such as those that occur when tanks are improperly operated, defective (e.g. damaged floating roof rim seals and deck fitting), or in disrepair.[49] These non-routine emissions must be included in the potential to emit.

IV. The Tank Design is Hazardous.

According to the TANKS 4.0.9d output in the Application, all of the tanks are internal floating roof tanks. These tanks present significant hazards when used without an inert blanket, which is not required in the proposed permit. Dissolved gases can be flashed off and separated from the liquid phase, resulting in unstable roofs, safety issues, and ultimately, higher emissions.

The upper flammability limit of methanol is 36% by volume, much higher than gasoline. Thus, methanol vapors can ignite and burn inside the tank vapor space. Further, during tank filling, methanol vapors are displaced through tank vents, creating potential flammability and toxicity hazards around tank. These hazards are typically controlled by excluding air from methanol tank vapor spaces by inerting or gas blanketing.[50] The Application and the proposed permit are silent on these issues. Further, the crude methanol tank is an even greater concern because, if all of the gases are not removed, the release of the gases under a floating roof could cause the roof to become unstable. Therefore, crude methanol is usually not stored in floating roof tanks, but rather fixed roof tanks vented to a control device.

The recently permitted St. James Methanol Plant, for example, rejected an internal floating roof tank for crude methanol storage due to these risks and instead selected a fixed roof tank with thermal oxidation.[51] This Facility also selected internal floating roof tanks with inert

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[48] Increase in methanol tanks VOC emissions from roof landing emissions = (8.46+9.32)0.4 = **7.11 ton/yr**.

[49] EPA, Draft EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems, p. 32, August 2014, Available at: http://www.epa.gov/ttn/chief/consentdecree/draft_report_review.pdf.

[50] Methanol Safe Handling Bulletin, Atmospheric Above Ground Tank Storage of Methanol, Available at: http://www.methanol.org/getattachment/Health-And-Safety/Technical-Bulletins/AtmosphericAboveGroundTankStorageMethanol-%281%29.pdf.aspx;

[51] South Louisiana Methanol, St. James Methanol Plant, St. James, Louisiana, Part 70 Title V/Prevention of Significant Deterioration Air Permit Application, July 2013.

gas blankets for product methanol tanks to address these hazards. St. James 7/13 Ap., § 3.0 BACT Analysis, pp. 43-44, EDMS Doc. ID. 9057147.

V. The Project is Piecemealed.

The Facility will be supplied with oxygen feed from an adjacent oxygen plant owned by Air Liquide. As Yuhuang Chemical will use all of the facility's output and it will be located on an adjacent property under common control, connected to the methanol plant by a pipeline, the oxygen plan is part of the Methanol Plant.[52] Thus, these two projects should be considered as one project for the purposes of NSR, PSD, major facility review (Title V) offsets, new source performance standards (NSPS), national emission standards for hazards air pollutants (NESHAPS), and any other applicable requirement.

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[52] Bill Lodge, Air Liquide Building $170 Million Unit to Supply St. James Parish Plant, BLODGE@THE ADVOCATE.COM, February 14, 2015, Available at: http://theadvocate.com/news/neworleans/neworleansnews/11566121-123/air-liquide-building-170-million.