Tulane University

Tulane Environmental Law Clinic

May 18, 2015

Via e-mail and
Federal Express –
Overnight Delivery

Administrator Gina McCarthy
U.S. Environmental Protection Agency
Ariel Rios Building, Mail Code 1101 A
1200 Pennsylvania Avenue, NW
Washington, DC 20460
Fax number (202) 501-1450

RE: Petition for Objection to Louisiana Proposed Title V Permit No. 2560-00295-V0 for the Operation of the Yuhuang Chemical Inc. Methanol Plant, St. James, Louisiana.

Dear Administrator McCarthy:

Enclosed is a petition requesting that the U.S. Environmental Protection Agency object to the initial Title V Permit No. 2560-00295-V0 issued by Louisiana Department of Environmental Quality to Yuhuang Chemical Inc. for the construction and operation of a new methanol manufacturing plant in St. James, Louisiana.

Thank you for your attention to this matter.

Sincerely,

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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

[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

[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

[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

[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

[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

[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

[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

[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> .

[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

[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

[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

[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

[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

[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

[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

[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

[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:

[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

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and

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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):

[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

[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

[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

[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.

[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.

[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

[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.

[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.

[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]

[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

[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.

[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

[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

[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.

[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.

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Dr. Fox has over 40 years of experience in the field of environmental engineering, including air pollution control (BACT, BART, MACT, LAER, RACT), cost effectiveness analyses, water quality and water supply investigations, hydrology, hazardous waste investigations, environmental permitting, nuisance investigations (odor, noise), environmental impact reports, CEQA/NEPA documentation, risk assessments, and litigation support.

EDUCATION

Ph.D. Environmental/Civil Engineering, University of California, Berkeley, 1980.
M.S. Environmental/Civil Engineering, University of California, Berkeley, 1975.
B.S. Physics (with high honors), University of Florida, Gainesville, 1971.

REGISTRATION

Registered Professional Engineer: Arizona (2001-2014: #36701; retired), California (2002-present; CH 6058), Florida (2001-present; #57886), Georgia (2002-2014; #PE027643; retired), Washington (2002-2014; #38692; retired), Wisconsin (2005-2014; #37595-006; retired)
Board Certified Environmental Engineer, American Academy of Environmental Engineers, Certified in Air Pollution Control (DEE #01-20014), 2002-present
Qualified Environmental Professional (QEP), Institute of Professional Environmental Practice (QEP #02-010007), 2001-present

PROFESSIONAL HISTORY

Environmental Management, Principal, 1981-present
Lawrence Berkeley National Laboratory, Principal Investigator, 1977-1981
University of California, Berkeley, Program Manager, 1976-1977
Bechtel, Inc., Engineer, 1971-1976, 1964-1966

PROFESSIONAL AFFILIATIONS

American Chemical Society (1981-2010)
Phi Beta Kappa (1970-present)
Sigma Pi Sigma (1970-present)

Who's Who Environmental Registry, PH Publishing, Fort Collins, CO, 1992.

Who's Who in the World, Marquis Who's Who, Inc., Chicago, IL, 11th Ed., p. 371, 1993-present.
Who's Who of American Women, Marquis Who's Who, Inc., Chicago, IL, 13th Ed., p. 264, 1984-present.
Who's Who in Science and Engineering, Marquis Who's Who, Inc., New Providence, NJ, 5th Ed., p. 414, 1999-present.
Who's Who in America, Marquis Who's Who, Inc., 59th Ed., 2005.
Guide to Specialists on Toxic Substances, World Environment Center, New York, NY, p. 80, 1980.
National Research Council Committee on Irrigation-Induced Water Quality Problems (Selenium), Subcommittee on Quality Control/Quality Assurance (1985-1990).
National Research Council Committee on Surface Mining and Reclamation, Subcommittee on Oil Shale (1978-80)

REPRESENTATIVE EXPERIENCE

Performed environmental and engineering investigations, as outlined below, for a wide range of industrial and commercial facilities including: petroleum refineries and upgrades thereto; reformulated fuels projects; refinery upgrades to process heavy sour crudes, including tar sands and light sweet crudes from the Eagle Ford and Bakken Formations; petroleum distribution terminals; coal, coke, and ore/mineral export terminals; LNG export, import, and storage terminals; crude-by-rail projects; shale oil plants; crude oil rail terminals; coal gasification & liquefaction plants; conventional and thermally enhanced oil production; underground storage tanks; pipelines; compressor stations; gasoline stations; landfills; railyards; hazardous waste treatment facilities; nuclear, hydroelectric, geothermal, wood, biomass, waste, tire-derived fuel, gas, oil, coke and coal-fired power plants; transmission lines; airports; hydrogen plants; petroleum coke calcining plants; coke plants; activated carbon manufacturing facilities; asphalt plants; cement plants; incinerators; flares; manufacturing facilities (e.g., semiconductors, electronic assembly, aerospace components, printed circuit boards, amusement park rides); lanthanide processing plants; ammonia plants; nitric acid plants; urea plants; food processing plants; almond hulling facilities; composting facilities; grain processing facilities; grain elevators; ethanol production facilities; soy bean oil extraction plants; biodiesel plants; paint formulation plants; wastewater treatment plants; marine terminals and ports; gas processing plants; steel mills; iron nugget production facilities; pig iron plant, based on blast furnace technology; direct reduced iron plant; acid regeneration facilities; railcar refinishing facility; battery manufacturing plants; pesticide manufacturing and repackaging facilities; pulp and paper mills; olefin plants; methanol plants; ethylene crackers; selective catalytic reduction (SCR) systems; selective noncatalytic reduction (SNCR) systems; halogen acid furnaces; contaminated property redevelopment projects (e.g., Mission Bay, Southern Pacific Railyards, Moscone Center expansion, San Diego Padres Ballpark); residential developments; commercial office parks, campuses, and shopping centers; server farms; transportation plans; and a wide range of mines

including sand and gravel, hard rock, limestone, nacholite, coal, molybdenum, gold, zinc, and oil shale.

EXPERT WITNESS/LITIGATION SUPPORT

- For the California Attorney General, assist in determining compliance with probation terms in the matter of People v. Chevron USA.
- For plaintiffs, assist in developing Petitioners' proof brief for National Parks Conservation Association et al v. U.S. EPA, Petition for Review of Final Administrative Action of the U.S. EPA, In the U.S. Court of Appeals for the Third Circuit, Docket No. 14-3147.
- For plaintiffs, expert witness in civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1997-2000) at the Cemex cement plant in Lyons, Colorado. Reviewed produced documents, prepared expert and rebuttal reports on PSD applicability based on NOx emission calculations for a collection of changes considered both individually and collectively. Deposed August 2011. *United States v. Cemex, Inc.*, In U.S. District Court for the District of Colorado (Civil Action No. 09-cv-00019-MSK-MEH). Case settled June 13, 2013.
- For plaintiffs, in civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1988 – 2000) at James De Young Units 3, 4, and 5. Reviewed produced documents, analyzed CEMS and EIA data, and prepared netting and BACT analyses for NOx, SO2, and PM10 (PSD case). Expert report February 24, 2010 and affidavit February 20, 2010. *Sierra Club v. City of Holland, et al.*, U.S. District Court, Western District of Michigan (Civil Action 1:08-cv-1183). Case settled. Consent Decree 1/19/14.
- For plaintiffs, in civil action alleging failure to obtain MACT permit, expert on potential to emit hydrogen chloride (HCl) from a new coal-fired boiler. Reviewed record, estimated HCl emissions, wrote expert report June 2010 and March 2013 (Cost to Install a Scrubber at the Lamar Repowering Project Pursuant to Case-by-Case MACT), deposed August 2010 and March 2013. *Wildearth Guardian et al. v. Lamar Utilities Board,* Civil Action No. 09-cv-02974, U.S. District Court, District of Colorado. Case settled August 2013.
- For plaintiffs, expert witness on permitting, emission calculations, and wastewater treatment for coal-to-gasoline plant. Reviewed produced documents. Assisted in preparation of comments on draft minor source permit. Wrote two affidavits on key issues in case. Presented direct and rebuttal testimony 10/27 - 10/28/10 on permit enforceability and failure to properly calculate potential to emit, including underestimate of flaring emissions and omission of VOC and CO emissions from wastewater treatment, cooling tower, tank roof landings, and malfunctions. *Sierra Club, Ohio Valley Environmental Coalition, Coal River Mountain Watch, West Virginia Highlands Conservancy v. John Benedict, Director, Division*

of Air Quality, West Virginia Department of Environmental Protection and TransGas Development System, LLC, Appeal No. 10-01-AQB. Virginia Air Quality Board remanded the permit on March 28, 2011 ordering reconsideration of potential to emit calculations, including: (1) support for assumed flare efficiency; (2) inclusion of startup, shutdown and malfunction emissions; and (3) inclusion of wastewater treatment emissions in potential to emit calculations.

- For plaintiffs, expert on BACT emission limits for gas-fired combined cycle power plant. Prepared declaration in support of CBE's Opposition to the United States' Motion for Entry of Proposed Amended Consent Decree. Assisted in settlement discussions. *U.S. EPA, Plaintiff, Communities for a Better Environment, Intervenor Plaintiff, v. Pacific Gas & Electric Company, et al.*, U.S. District Court, Northern District of California, San Francisco Division, Case No. C-09-4503 SI.
- Technical expert in confidential settlement discussions with large coal-fired utility on BACT control technology and emission limits for NOx, SO2, PM, PM2.5, and CO for new natural gas fired combined cycle and simple cycle turbines with oil backup. (July 2010). Case settled.
- For plaintiffs, expert witness in remedy phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1998-99) at Gallagher Units 1 and 3. Reviewed produced documents, prepared expert and rebuttal reports on historic and current-day BACT for SO2, control costs, and excess emissions of SO2. Deposed 11/18/09. *United States et al. v. Cinergy, et al.*, In U.S. District Court for the Southern District of Indiana, Indianapolis Division, Civil Action No. IP99-1693 C-M/S. Settled 12/22/09.
- For plaintiffs, expert witness on MACT, BACT for NOx, and enforceability in an administrative appeal of draft state air permit issued for four 300-MW pet-coke-fired CFBs. Reviewed produced documents and prepared prefiled testimony. Deposed 10/8/09 and 11/9/09. Testified 11/10/09. *Application of Las Brisas Energy Center, LLC for State Air Quality Permit*; before the State Office of Administrative Hearings, Texas. Permit remanded 3/29/10 as LBEC failed to meet burden of proof on a number of issues including MACT. Texas Court of Appeals dismissed an appeal to reinstate the permit. The Texas Commission on Environmental Quality and Las Brisas Energy Center, LLC sought to overturn the Court of Appeals decision but moved to have their appeal dismissed in August 2013.
- For defense, expert witness in unlawful detainer case involving a gasoline station, minimart, and residential property with contamination from leaking underground storage tanks. Reviewed agency files and inspected site. Presented expert testimony on July 6, 2009, on causes of, nature and extent of subsurface contamination. *A. Singh v. S. Assaedi,* in Contra Costa County Superior Court, CA. Settled August 2009.

- For plaintiffs, expert witness on netting and enforceability for refinery being upgraded to process tar sands crude. Reviewed produced documents. Prepared expert and rebuttal reports addressing use of emission factors for baseline, omitted sources including coker, flares, tank landings and cleaning, and enforceability. Deposed. *In the Matter of Objection to the Issuance of Significant Source Modification Permit No. 089-25484-00453 to BP Products North America Inc., Whiting Business Unit, Save the Dunes Council, Inc., Sierra Club., Inc., Hoosier Environmental Council et al., Petitioners, B. P. Products North American, Respondents/Permittee,* before the Indiana Office of Environmental Adjudication.
- For plaintiffs, expert witness on BACT, MACT, and enforceability in appeal of Title V permit issued to 600 MW coal-fired power plant burning Powder River Basin coal. Prepared technical comments on draft air permit. Reviewed record on appeal, drafted BACT, MACT, and enforceability pre-filed testimony. Drafted MACT and enforceability pre-filed rebuttal testimony. Deposed March 24, 2009. Testified June 10, 2009. *In Re: Southwestern Electric Power Company*, Arkansas Pollution Control and Ecology Commission, Consolidated Docket No. 08-006-P. Recommended Decision issued December 9, 2009 upholding issued permit. Commission adopted Recommended Decision January 22, 2010.
- For plaintiffs, expert witness in remedy phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1989-1992) at Wabash Units 2, 3 and 5. Reviewed produced documents, prepared expert and rebuttal report on historic and current-day BACT for NOx and SO2, control costs, and excess emissions of NOx, SO2, and mercury. Deposed 10/21/08. *United States et al. v. Cinergy, et al.*, In U.S. District Court for the Southern District of Indiana, Indianapolis Division, Civil Action No. IP99-1693 C-M/S. Testified 2/3/09. Memorandum Opinion & Order 5-29-09 requiring shutdown of Wabash River Units 2, 3, 5 by September 30, 2009, run at baseline until shutdown, and permanently surrender SO2 emission allowances.
- For plaintiffs, expert witness in liability phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for three historic modifications (1997-2001) at two portland cement plants involving three cement kilns. Reviewed produced documents, analyzed CEMS data covering subject period, prepared netting analysis for NOx, SO_2 and CO, and prepared expert and rebuttal reports. *United States v. Cemex California Cement,* In U.S. District Court for the Central District of California, Eastern Division, Case No. ED CV 07-00223-GW (JCRx), Settled 1/15/09.
- For intervenors Clean Wisconsin and Citizens Utility Board, prepared data requests, reviewed discovery and expert report. Prepared prefiled direct, rebuttal and surrebuttal testimony on cost to extend life of existing Oak Creek Units 5-8 and cost to address future regulatory requirements to determine whether to control or shutdown one or more of the units. Oral testimony 2/5/08. Application for a Certificate of Authority to Install Wet Flue Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment

for Control of Sulfur Dioxide and Nitrogen Oxide Emissions at Oak Creek Power Plant Units 5, 6, 7 and 8, WPSC Docket No. 6630-CE-299.

- For plaintiffs, expert witness on alternatives analysis and BACT for NOx, SO2, total PM10, and sulfuric acid mist in appeal of PSD permit issued to 1200 MW coal fired power plant burning Powder River Basin and/or Central Appalachian coal (Longleaf). Assisted in drafting technical comments on NOx on draft permit. Prepared expert disclosure. Presented 8+ days of direct and rebuttal expert testimony. Attended all 21 days of evidentiary hearing from 9/5/07 – 10/30/07 assisting in all aspects of hearing. *Friends of the Chatahooche and Sierra Club v. Dr. Carol Couch, Director, Environmental Protection Division of Natural Resources Department, Respondent, and Longleaf Energy Associates, Intervener*. ALJ Final Decision 1/11/08 denying petition. ALJ Order vacated & remanded for further proceedings, Fulton County Superior Court, 6/30/08. Court of Appeals of GA remanded the case with directions that the ALJ's final decision be vacated to consider the evidence under the correct standard of review, July 9, 2009. The ALJ issued an opinion April 2, 2010 in favor of the applicant. Final permit issued April 2010.
- For plaintiffs, expert witness on diesel exhaust in inverse condemnation case in which Port expanded maritime operations into residential neighborhoods, subjecting plaintiffs to noise, light, and diesel fumes. Measured real-time diesel particulate concentrations from marine vessels and tug boats on plaintiffs' property. Reviewed documents, depositions, DVDs, and photographs provided by counsel. Deposed. Testified October 24, 2006. *Ann Chargin, Richard Hackett, Carolyn Hackett, et al. v. Stockton Port District*, Superior Court of California, County of San Joaquin, Stockton Branch, No. CV021015. Judge ruled for plaintiffs.
- For plaintiffs, expert witness on NOx emissions and BACT in case alleging failure to obtain necessary permits and install controls on gas-fired combined-cycle turbines. Prepared and reviewed (applicant analyses) of NOx emissions, BACT analyses (water injection, SCR, ultra low NOx burners), and cost-effectiveness analyses based on site visit, plant operating records, stack tests, CEMS data, and turbine and catalyst vendor design information. Participated in negotiations to scope out consent order. *United States v. Nevada Power*. Case settled June 2007, resulting in installation of dry low NOx burners (5 ppm NOx averaged over 1 hr) on four units and a separate solar array at a local business.
- For plaintiffs, expert witness in appeal of PSD permit issued to 850 MW coal fired boiler burning Powder River Basin coal (Iatan Unit 2) on BACT for particulate matter, sulfuric acid mist and opacity and emission calculations for alleged historic violations of PSD. Assisted in drafting technical comments, petition for review, discovery requests, and responses to discovery requests. Reviewed produced documents. Prepared expert report on BACT for particulate matter. Assisted with expert depositions. Deposed February 7, 8, 27, 28, 2007. *In Re PSD Construction Permit Issued to Great Plains Energy, Kansas City Power & Light – Iatan Generating Station, Sierra Club v. Missouri Department of Natural Resources, Great*

Plains Energy, and Kansas City Power & Light. Case settled March 27, 2007, providing offsets for over 6 million ton/yr of CO2 and lower NOx and SO_2 emission limits.

- For plaintiffs, expert witness in remedy phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications of coal-fired boilers and associated equipment. Reviewed produced documents, prepared expert report on cost to retrofit 24 coal-fired power plants with scrubbers designed to remove 99% of the sulfur dioxide from flue gases. Prepared supplemental and expert report on cost estimates and BACT for SO2 for these 24 complaint units. Deposed 1/30/07 and 3/14/07. *United States and State of New York et al. v. American Electric Power,* In U.S. District Court for the Southern District of Ohio, Eastern Division, Consolidated Civil Action Nos. C2-99-1182 and C2-99-1250. Settlement announced 10/9/07.
- For plaintiffs, expert witness on BACT, enforceability, and alternatives analysis in appeal of PSD permit issued for a 270-MW pulverized coal fired boiler burning Powder River Basin coal (City Utilities Springfield Unit 2). Reviewed permitting file and assisted counsel draft petition and prepare and respond to interrogatories and document requests. Reviewed interrogatory responses and produced documents. Assisted with expert depositions. Deposed August 2005. Evidentiary hearings October 2005. *In the Matter of Linda Chipperfield and Sierra Club v. Missouri Department of Natural Resources.* Missouri Supreme Court denied review of adverse lower court rulings August 2007.
- For plaintiffs, expert witness in civil action relating to plume touchdowns at AEP's Gavin coal-fired power plant. Assisted counsel draft interrogatories and document requests. Reviewed responses to interrogatories and produced documents. Prepared expert report "Releases of Sulfuric Acid Mist from the Gavin Power Station." The report evaluates sulfuric acid mist releases to determine if AEP complied with the requirements of CERCLA Section 103(a) and EPCRA Section 304. This report also discusses the formation, chemistry, release characteristics, and abatement of sulfuric acid mist in support of the claim that these releases present an imminent and substantial endangerment to public health under Section 7002(a)(1)(B) of the Resource Conservation and Recovery Act ("RCRA"). *Citizens Against Pollution v. Ohio Power Company*, In the U.S. District Court for the Southern District of Ohio, Eastern Division, Civil Action No. 2-04-cv-371. Case settled 12-8-06.
- For petitioners, expert witness in contested case hearing on BACT, enforceability, and emission estimates for an air permit issued to a 500-MW supercritical Power River Basin coal-fired boiler (Weston Unit 4). Assisted counsel prepare comments on draft air permit and respond to and draft discovery. Reviewed produced file, deposed (7/05), and prepared expert report on BACT and enforceability. Evidentiary hearings September 2005. *In the Matter of an Air Pollution Control Construction Permit Issued to Wisconsin Public Service Corporation for the Construction and Operation of a 500 MW Pulverized Coal-fired Power Plant Known as Weston Unit 4 in Marathon County, Wisconsin*, Case No. IH-04-21. The

Final Order, issued 2/10/06, lowered the NOx BACT limit from 0.07 lb/MMBtu to 0.06 lb/MMBtu based on a 30-day average, added a BACT SO2 control efficiency, and required a 0.0005% high efficiency drift eliminator as BACT for the cooling tower. The modified permit, including these provisions, was issued 3/28/07. Additional appeals in progress.

- For plaintiffs, adviser on technical issues related to Citizen Suit against U.S. EPA regarding failure to update New Source Performance Standards for petroleum refineries, 40 CFR 60, Subparts J, VV, and GGG. *Our Children's Earth Foundation and Sierra Club v. U.S. EPA et al.* Case settled July 2005. CD No. C 05-00094 CW, U.S. District Court, Northern District of California – Oakland Division. Proposed revisions to standards of performance for petroleum refineries published 72 FR 27178 (5/14/07).
- For interveners, reviewed proposed Consent Decree settling Clean Air Act violations due to historic modifications of boilers and associated equipment at two coal-fired power plants. In response to stay order, reviewed the record, selected one representative activity at each of seven generating units, and analyzed to identify CAA violations. Identified NSPS and NSR violations for NOx, SO_2, PM/PM10, and sulfuric acid mist. Summarized results in an expert report. *United States of America, and Michael A. Cox, Attorney General of the State of Michigan, ex rel. Michigan Department of Environmental Quality, Plaintiffs, and Clean Wisconsin, Sierra Club, and Citizens' Utility Board, Intervenors, v. Wisconsin Electric Power Company, Defendant*, U.S. District Court for the Eastern District of Wisconsin, Civil Action No. 2:03-CV-00371-CNC. Order issued 10-1-07 denying petition.
- For a coalition of Nevada labor organizations (ACE), reviewed preliminary determination to issue a Class I Air Quality Operating Permit to Construct and supporting files for a 250-MW pulverized coal-fired boiler (Newmont). Prepared about 100 pages of technical analyses and comments on BACT, MACT, emission calculations, and enforceability. Assisted counsel draft petition and reply brief appealing PSD permit to U.S. EPA Environmental Appeals Board (EAB). Order denying review issued 12/21/05. *In re Newmont Nevada Energy Investment, LLC, TS Power Plant*, PSD Appeal No. 05-04 (EAB 2005).
- For petitioners and plaintiffs, reviewed and prepared comments on air quality and hazardous waste based on negative declaration for refinery ultra low sulfur diesel project located in SCAQMD. Reviewed responses to comments and prepared responses. Prepared declaration and presented oral testimony before SCAQMD Hearing Board on exempt sources (cooling towers) and calculation of potential to emit under NSR. Petition for writ of mandate filed March 2005. Case remanded by Court of Appeals to trial court to direct SCAQMD to re-evaluate the potential environmental significance of NOx emissions resulting from the project in accordance with court's opinion. California Court of Appeals, Second Appellate Division, on December 18, 2007, affirmed in part (as to baseline) and denied in part. *Communities for a Better Environment v. South Coast Air Quality Management District and ConocoPhillips and Carlos Valdez et al v. South Coast Air Quality Management District and*

ConocoPhillips. Certified for partial publication 1/16/08. Appellate Court opinion upheld by CA Supreme Court 3/15/10. *(2010) 48 Cal.4th 310.*

- For amici seeking to amend a proposed Consent Decree to settle alleged NSR violations at Chevron refineries, reviewed proposed settlement, related files, subject modifications, and emission calculations. Prepared declaration on emission reductions, identification of NSR and NSPS violations, and BACT/LAER for FCCUs, heaters and boilers, flares, and sulfur recovery plants. *U.S. et al. v. Chevron U.S.A.*, Northern District of California, Case No. C 03-04650. Memorandum and Order Entering Consent Decree issued June 2005. Case No. C 03-4650 CRB.
- For petitioners, prepared declaration on enforceability of periodic monitoring requirements, in response to EPA's revised interpretation of 40 CFR 70.6(c)(1). This revision limited additional monitoring required in Title V permits. 69 FR 3203 (Jan. 22, 2004). *Environmental Integrity Project et al. v. EPA* (U.S. Court of Appeals for the District of Columbia). Court ruled the Act requires all Title V permits to contain monitoring requirements to assure compliance. *Sierra Club v. EPA*, 536 F.3d 673 (D.C. Cir. 2008).
- For interveners in application for authority to construct a 500 MW supercritical coal-fired generating unit before the Wisconsin Public Service Commission, prepared pre-filed written direct and rebuttal testimony with oral cross examination and rebuttal on BACT and MACT (Weston 4). Prepared written comments on BACT, MACT, and enforceability on draft air permit for same facility.
- For property owners in Nevada, evaluated the environmental impacts of a 1,450-MW coal-fired power plant proposed in a rural area adjacent to the Black Rock Desert and Granite Range, including emission calculations, air quality modeling, comments on proposed use permit to collect preconstruction monitoring data, and coordination with agencies and other interested parties. Project cancelled.
- For environmental organizations, reviewed draft PSD permit for a 600-MW coal-fired power plant in West Virginia (Longview). Prepared comments on permit enforceability; coal washing; BACT for SO_2 and PM10; Hg MACT; and MACT for HCl, HF, non-Hg metallic HAPs, and enforceability. Assist plaintiffs draft petition appealing air permit. Retained as expert to develop testimony on MACT, BACT, offsets, enforceability. Participate in settlement discussions. Case settled July 2004.
- For petitioners, reviewed record produced in discovery and prepared affidavit on emissions of carbon monoxide and volatile organic compounds during startup of GE 7FA combustion turbines to successfully establish plaintiff standing. *Sierra Club et al. v. Georgia Power Company* (Northern District of Georgia).
- For building trades, reviewed air quality permitting action for 1500-MW coal-fired power plant before the Kentucky Department for Environmental Protection (Thoroughbred).

- For petitioners, expert witness in administrative appeal of the PSD/Title V permit issued to a 1500-MW coal-fired power plant. Reviewed over 60,000 pages of produced documents, prepared discovery index, identified and assembled plaintiff exhibits. Deposed. Assisted counsel in drafting discovery requests, with over 30 depositions, witness cross examination, and brief drafting. Presented over 20 days of direct testimony, rebuttal and sur-rebuttal, with cross examination on BACT for NOx, SO_2, and PM/PM10; MACT for Hg and non-Hg metallic HAPs; emission estimates for purposes of Class I and II air modeling; risk assessment; and enforceability of permit limits. Evidentiary hearings from November 2003 to June 2004. *Sierra Club et al. v. Natural Resources & Environmental Protection Cabinet, Division of Air Quality and Thoroughbred Generating Company et al.* Hearing Officer Decision issued August 9, 2005 finding in favor of plaintiffs on counts as to risk, BACT (IGCC/CFB, NOx, SO_2, Hg, Be), single source, enforceability, and errors and omissions. Assist counsel draft exceptions. Cabinet Secretary issued Order April 11, 2006 denying Hearing Offer's report, except as to NOx BACT, Hg, 99% SO2 control and certain errors and omissions.
- For citizens group in Massachusetts, reviewed, commented on, and participated in permitting of pollution control retrofits of coal-fired power plant (Salem Harbor).
- Assisted citizens group and labor union challenge issuance of conditional use permit for a 317,000 ft^2 discount store in Honolulu without any environmental review. In support of a motion for preliminary injunction, prepared 7-page declaration addressing public health impacts of diesel exhaust from vehicles serving the Project. In preparation for trial, prepared 20-page preliminary expert report summarizing results of diesel exhaust and noise measurements at two big box retail stores in Honolulu, estimated diesel PM10 concentrations for Project using ISCST, prepared a cancer health risk assessment based on these analyses, and evaluated noise impacts.
- Assisted environmental organizations to challenge the DOE Finding of No Significant Impact (FONSI) for the Baja California Power and Sempra Energy Resources Cross-Border Transmissions Lines in the U.S. and four associated power plants located in Mexico (DOE EA-1391). Prepared 20-page declaration in support of motion for summary judgment addressing emissions, including CO_2 and NH_3, offsets, BACT, cumulative air quality impacts, alternative cooling systems, and water use and water quality impacts. Plaintiff's motion for summary judgment granted in part. U.S. District Court, Southern District decision concluded that the Environmental Assessment and FONSI violated NEPA and the APA due to their inadequate analysis of the potential controversy surrounding the project, water impacts, impacts from NH_3 and CO_2, alternatives, and cumulative impacts. *Border Power Plant Working Group v. Department of Energy and Bureau of Land Management*, Case No. 02-CV-513-IEG (POR) (May 2, 2003).
- For Sacramento school, reviewed draft air permit issued for diesel generator located across from playfield. Prepared comments on emission estimates, enforceability, BACT, and health impacts of diesel exhaust. Case settled. BUG trap installed on the diesel generator.

- Assisted unions in appeal of Title V permit issued by BAAQMD to carbon plant that manufactured coke. Reviewed District files, identified historic modifications that should have triggered PSD review, and prepared technical comments on Title V permit. Reviewed responses to comments and assisted counsel draft appeal to BAAQMD hearing board, opening brief, motion to strike, and rebuttal brief. Case settled.
- Assisted California Central Coast city obtain controls on a proposed new city that would straddle the Ventura-Los Angeles County boundary. Reviewed several environmental impact reports, prepared an air quality analysis, a diesel exhaust health risk assessment, and detailed review comments. Governor intervened and State dedicated the land for conservation purposes April 2004.
- Assisted Central California city to obtain controls on large alluvial sand quarry and asphalt plant proposing a modernization. Prepared comments on Negative Declaration on air quality, public health, noise, and traffic. Evaluated process flow diagrams and engineering reports to determine whether proposed changes increased plant capacity or substantially modified plant operations. Prepared comments on application for categorical exemption from CEQA. Presented testimony to County Board of Supervisors. Developed controls to mitigate impacts. Assisted counsel draft Petition for Writ. Case settled June 2002. Substantial improvements in plant operations were obtained including cap on throughput, dust control measures, asphalt plant loadout enclosure, and restrictions on truck routes.
- Assisted oil companies on the California Central Coast in defending class action citizen's lawsuit alleging health effects due to emissions from gas processing plant and leaking underground storage tanks. Reviewed regulatory and other files and advised counsel on merits of case. Case settled November 2001.
- Assisted oil company on the California Central Coast in defending property damage claims arising out of a historic oil spill. Reviewed site investigation reports, pump tests, leachability studies, and health risk assessments, participated in design of additional site characterization studies to assess health impacts, and advised counsel on merits of case. Prepare health risk assessment.
- Assisted unions in appeal of Initial Study/Negative Declaration ("IS/ND") for an MTBE phaseout project at a Bay Area refinery. Reviewed IS/ND and supporting agency permitting files and prepared technical comments on air quality, groundwater, and public health impacts. Reviewed responses to comments and final IS/ND and ATC permits and assisted counsel to draft petitions and briefs appealing decision to Air District Hearing Board. Presented sworn direct and rebuttal testimony with cross examination on groundwater impacts of ethanol spills on hydrocarbon contamination at refinery. Hearing Board ruled 5 to 0 in favor of appellants, remanding ATC to district to prepare an EIR.
- Assisted Florida cities in challenging the use of diesel and proposed BACT determinations in prevention of significant deterioration (PSD) permits issued to two 510-MW simple cycle

peaking electric generating facilities and one 1,080-MW simple cycle/combined cycle facility. Reviewed permit applications, draft permits, and FDEP engineering evaluations, assisted counsel in drafting petitions and responding to discovery. Participated in settlement discussions. Cases settled or applications withdrawn.

- Assisted large California city in federal lawsuit alleging peaker power plant was violating its federal permit. Reviewed permit file and applicant's engineering and cost feasibility study to reduce emissions through retrofit controls. Advised counsel on feasible and cost-effective NOx, SOx, and PM10 controls for several 1960s diesel-fired Pratt and Whitney peaker turbines. Case settled.
- Assisted coalition of Georgia environmental groups in evaluating BACT determinations and permit conditions in PSD permits issued to several large natural gas-fired simple cycle and combined-cycle power plants. Prepared technical comments on draft PSD permits on BACT, enforceability of limits, and toxic emissions. Reviewed responses to comments, advised counsel on merits of cases, participated in settlement discussions, presented oral and written testimony in adjudicatory hearings, and provided technical assistance as required. Cases settled or won at trial.
- Assisted construction unions in review of air quality permitting actions before the Indiana Department of Environmental Management ("IDEM") for several natural gas-fired simple cycle peaker and combined cycle power plants.
- Assisted coalition of towns and environmental groups in challenging air permits issued to 523 MW dual fuel (natural gas and distillate) combined-cycle power plant in Connecticut. Prepared technical comments on draft permits and 60 pages of written testimony addressing emission estimates, startup/shutdown issues, BACT/LAER analyses, and toxic air emissions. Presented testimony in adjudicatory administrative hearings before the Connecticut Department of Environmental Protection in June 2001 and December 2001.
- Assisted various coalitions of unions, citizens groups, cities, public agencies, and developers in licensing and permitting of over 110 coal, gas, oil, biomass, and pet coke-fired power plants generating over 75,000 MW of electricity. These included base-load, combined cycle, simple cycle, and peaker power plants in Alaska, Arizona, Arkansas, California, Colorado, Georgia, Florida, Illinois, Indiana, Kentucky, Michigan, Missouri, Ohio, Oklahoma, Oregon, Texas, West Virginia, Wisconsin, and elsewhere. Prepared analyses of and comments on applications for certification, preliminary and final staff assessments, and various air, water, wastewater, and solid waste permits issued by local agencies. Presented written and oral testimony before various administrative bodies on hazards of ammonia use and transportation, health effects of air emissions, contaminated property issues, BACT/LAER issues related to SCR and SCONOx, criteria and toxic pollutant emission estimates, MACT analyses, air quality modeling, water supply and water quality issues, and methods to reduce water use, including dry cooling, parallel dry-wet cooling, hybrid cooling, and zero liquid discharge systems.

- Assisted unions, cities, and neighborhood associations in challenging an EIR issued for the proposed expansion of the Oakland Airport. Reviewed two draft EIRs and prepared a health risk assessment and extensive technical comments on air quality and public health impacts. The California Court of Appeals, First Appellate District, ruled in favor of appellants and plaintiffs, concluding that the EIR "2) erred in using outdated information in assessing the emission of toxic air contaminants (TACs) from jet aircraft; 3) failed to support its decision not to evaluate the health risks associated with the emission of TACs with meaningful analysis," thus accepting my technical arguments and requiring the Port to prepare a new EIR. See *Berkeley Keep Jets Over the Bay Committee, City of San Leandro, and City of Alameda et al. v. Board of Port Commissioners* (August 30, 2001) 111 Cal.Rptr.2d 598.
- Assisted lessor of former gas station with leaking underground storage tanks and TCE contamination from adjacent property. Lessor held option to purchase, which was forfeited based on misrepresentation by remediation contractor as to nature and extent of contamination. Remediation contractor purchased property. Reviewed regulatory agency files and advised counsel on merits of case. Case not filed.
- Advised counsel on merits of several pending actions, including a Proposition 65 case involving groundwater contamination at an explosives manufacturing firm and two former gas stations with leaking underground storage tanks.
- Assisted defendant foundry in Oakland in a lawsuit brought by neighbors alleging property contamination, nuisance, trespass, smoke, and health effects from foundry operation. Inspected and sampled plaintiff's property. Advised counsel on merits of case. Case settled.
- Assisted business owner facing eminent domain eviction. Prepared technical comments on a negative declaration for soil contamination and public health risks from air emissions from a proposed redevelopment project in San Francisco in support of a CEQA lawsuit. Case settled.
- Assisted neighborhood association representing residents living downwind of a Berkeley asphalt plant in separate nuisance and CEQA lawsuits. Prepared technical comments on air quality, odor, and noise impacts, presented testimony at commission and council meetings, participated in community workshops, and participated in settlement discussions. Cases settled. Asphalt plant was upgraded to include air emission and noise controls, including vapor collection system at truck loading station, enclosures for noisy equipment, and improved housekeeping.
- Assisted a Fortune 500 residential home builder in claims alleging health effects from faulty installation of gas appliances. Conducted indoor air quality study, advised counsel on merits of case, and participated in discussions with plaintiffs. Case settled.
- Assisted property owners in Silicon Valley in lawsuit to recover remediation costs from insurer for large TCE plume originating from a manufacturing facility. Conducted investigations to demonstrate sudden and accidental release of TCE, including groundwater

modeling, development of method to date spill, preparation of chemical inventory, investigation of historical waste disposal practices and standards, and on-site sewer and storm drainage inspections and sampling. Prepared declaration in opposition to motion for summary judgment. Case settled.

- Assisted residents in east Oakland downwind of a former battery plant in class action lawsuit alleging property contamination from lead emissions. Conducted historical research and dry deposition modeling that substantiated claim. Participated in mediation at JAMS. Case settled.
- Assisted property owners in West Oakland who purchased a former gas station that had leaking underground storage tanks and groundwater contamination. Reviewed agency files and advised counsel on merits of case. Prepared declaration in opposition to summary judgment. Prepared cost estimate to remediate site. Participated in settlement discussions. Case settled.
- Consultant to counsel representing plaintiffs in two Clean Water Act lawsuits involving selenium discharges into San Francisco Bay from refineries. Reviewed files and advised counsel on merits of case. Prepared interrogatory and discovery questions, assisted in deposing opposing experts, and reviewed and interpreted treatability and other technical studies. Judge ruled in favor of plaintiffs.
- Assisted oil company in a complaint filed by a resident of a small California beach community alleging that discharges of tank farm rinse water into the sanitary sewer system caused hydrogen sulfide gas to infiltrate residence, sending occupants to hospital. Inspected accident site, interviewed parties to the event, and reviewed extensive agency files related to incident. Used chemical analysis, field simulations, mass balance calculations, sewer hydraulic simulations with SWMM44, atmospheric dispersion modeling with SCREEN3, odor analyses, and risk assessment calculations to demonstrate that the incident was caused by a faulty drain trap and inadequate slope of sewer lateral on resident's property. Prepared a detailed technical report summarizing these studies. Case settled.
- Assisted large West Coast city in suit alleging that leaking underground storage tanks on city property had damaged the waterproofing on downgradient building, causing leaks in an underground parking structure. Reviewed subsurface hydrogeologic investigations and evaluated studies conducted by others documenting leakage from underground diesel and gasoline tanks. Inspected, tested, and evaluated waterproofing on subsurface parking structure. Waterproofing was substandard. Case settled.
- Assisted residents downwind of gravel mine and asphalt plant in Siskiyou County, California, in suit to obtain CEQA review of air permitting action. Prepared two declarations analyzing air quality and public health impacts. Judge ruled in favor of plaintiffs, closing mine and asphalt plant.

- Assisted defendant oil company on the California Central Coast in class action lawsuit alleging property damage and health effects from subsurface petroleum contamination. Reviewed documents, prepared risk calculations, and advised counsel on merits of case. Participated in settlement discussions. Case settled.
- Assisted defendant oil company in class action lawsuit alleging health impacts from remediation of petroleum contaminated site on California Central Coast. Reviewed documents, designed and conducted monitoring program, and participated in settlement discussions. Case settled.
- Consultant to attorneys representing irrigation districts and municipal water districts to evaluate a potential challenge of USFWS actions under CVPIA section 3406(b)(2). Reviewed agency files and collected and analyzed hydrology, water quality, and fishery data. Advised counsel on merits of case. Case not filed.
- Assisted residents downwind of a Carson refinery in class action lawsuit involving soil and groundwater contamination, nuisance, property damage, and health effects from air emissions. Reviewed files and provided advise on contaminated soil and groundwater, toxic emissions, and health risks. Prepared declaration on refinery fugitive emissions. Prepared deposition questions and reviewed deposition transcripts on air quality, soil contamination, odors, and health impacts. Case settled.
- Assisted residents downwind of a Contra Costa refinery who were affected by an accidental release of naphtha. Characterized spilled naphtha, estimated emissions, and modeled ambient concentrations of hydrocarbons and sulfur compounds. Deposed. Presented testimony in binding arbitration at JAMS. Judge found in favor of plaintiffs.
- Assisted residents downwind of Contra Costa County refinery in class action lawsuit alleging property damage, nuisance, and health effects from several large accidents as well as routine operations. Reviewed files and prepared analyses of environmental impacts. Prepared declarations, deposed, and presented testimony before jury in one trial and judge in second. Case settled.
- Assisted business owner claiming damages from dust, noise, and vibration during a sewer construction project in San Francisco. Reviewed agency files and PM10 monitoring data and advised counsel on merits of case. Case settled.
- Assisted residents downwind of Contra Costa County refinery in class action lawsuit alleging property damage, nuisance, and health effects. Prepared declaration in opposition to summary judgment, deposed, and presented expert testimony on accidental releases, odor, and nuisance before jury. Case thrown out by judge, but reversed on appeal and not retried.
- Presented testimony in small claims court on behalf of residents claiming health effects from hydrogen sulfide from flaring emissions triggered by a power outage at a Contra Costa County refinery. Analyzed meteorological and air quality data and evaluated potential health

risks of exposure to low concentrations of hydrogen sulfide. Judge awarded damages to plaintiffs.

- Assisted construction unions in challenging PSD permit for an Indiana steel mill. Prepared technical comments on draft PSD permit, drafted 70-page appeal of agency permit action to the Environmental Appeals Board challenging permit based on faulty BACT analysis for electric arc furnace and reheat furnace and faulty permit conditions, among others, and drafted briefs responding to four parties. EPA Region V and the EPA General Counsel intervened as amici, supporting petitioners. EAB ruled in favor of petitioners, remanding permit to IDEM on three key issues, including BACT for the reheat furnace and lead emissions from the EAF. Drafted motion to reconsider three issues. Prepared 69 pages of technical comments on revised draft PSD permit. Drafted second EAB appeal addressing lead emissions from the EAF and BACT for reheat furnace based on European experience with SCR/SNCR. Case settled. Permit was substantially improved. See *In re: Steel Dynamics, Inc.*, PSD Appeal Nos. 99-4 & 99-5 (EAB June 22, 2000).
- Assisted defendant urea manufacturer in Alaska in negotiations with USEPA to seek relief from penalties for alleged violations of the Clean Air Act. Reviewed and evaluated regulatory files and monitoring data, prepared technical analysis demonstrating that permit limits were not violated, and participated in negotiations with EPA to dismiss action. Fines were substantially reduced and case closed.
- Assisted construction unions in challenging PSD permitting action for an Indiana grain mill. Prepared technical comments on draft PSD permit and assisted counsel draft appeal of agency permit action to the Environmental Appeals Board challenging permit based on faulty BACT analyses for heaters and boilers and faulty permit conditions, among others. Case settled.
- As part of a consent decree settling a CEQA lawsuit, assisted neighbors of a large west coast port in negotiations with port authority to secure mitigation for air quality impacts. Prepared technical comments on mobile source air quality impacts and mitigation and negotiated a $9 million CEQA mitigation package. Represented neighbors on technical advisory committee established by port to implement the air quality mitigation program. Program successfully implemented.
- Assisted construction unions in challenging permitting action for a California hazardous waste incinerator. Prepared technical comments on draft permit, assisted counsel prepare appeal of EPA permit to the Environmental Appeals Board. Participated in settlement discussions on technical issues with applicant and EPA Region 9. Case settled.
- Assisted environmental group in challenging DTSC Negative Declaration on a hazardous waste treatment facility. Prepared technical comments on risk of upset, water, and health risks. Writ of mandamus issued.

- Assisted several neighborhood associations and cities impacted by quarries, asphalt plants, and cement plants in Alameda, Shasta, Sonoma, and Mendocino counties in obtaining mitigations for dust, air quality, public health, traffic, and noise impacts from facility operations and proposed expansions.
- For over 100 industrial facilities, commercial/campus, and redevelopment projects, developed the record in preparation for CEQA and NEPA lawsuits. Prepared technical comments on hazardous materials, solid wastes, public utilities, noise, worker safety, air quality, public health, water resources, water quality, traffic, and risk of upset sections of EIRs, EISs, FONSIs, initial studies, and negative declarations. Assisted counsel in drafting petitions and briefs and prepared declarations.
- For several large commercial development projects and airports, assisted applicant and counsel prepare defensible CEQA documents, respond to comments, and identify and evaluate "all feasible" mitigation to avoid CEQA challenges. This work included developing mitigation programs to reduce traffic-related air quality impacts based on energy conservation programs, solar, low-emission vehicles, alternative fuels, exhaust treatments, and transportation management associations.

SITE INVESTIGATION/REMEDIATION/CLOSURE

- Technical manager and principal engineer for characterization, remediation, and closure of waste management units at former Colorado oil shale plant. Constituents of concern included BTEX, As, 1,1,1-TCA, and TPH. Completed groundwater monitoring programs, site assessments, work plans, and closure plans for seven process water holding ponds, a refinery sewer system, and processed shale disposal area. Managed design and construction of groundwater treatment system and removal actions and obtained clean closure.
- Principal engineer for characterization, remediation, and closure of process water ponds at a former lanthanide processing plant in Colorado. Designed and implemented groundwater monitoring program and site assessments and prepared closure plan.
- Advised the city of Sacramento on redevelopment of two former railyards. Reviewed work plans, site investigations, risk assessment, RAPS, RI/FSs, and CEQA documents. Participated in the development of mitigation strategies to protect construction and utility workers and the public during remediation, redevelopment, and use of the site, including buffer zones, subslab venting, rail berm containment structure, and an environmental oversight plan.
- Provided technical support for the investigation of a former sanitary landfill that was redeveloped as single family homes. Reviewed and/or prepared portions of numerous documents, including health risk assessments, preliminary endangerment assessments, site investigation reports, work plans, and RI/FSs. Historical research to identify historic waste

disposal practices to prepare a preliminary endangerment assessment. Acquired, reviewed, and analyzed the files of 18 federal, state, and local agencies, three sets of construction field notes, analyzed 21 aerial photographs and interviewed 14 individuals associated with operation of former landfill. Assisted counsel in defending lawsuit brought by residents alleging health impacts and diminution of property value due to residual contamination. Prepared summary reports.

- Technical oversight of characterization and remediation of a nitrate plume at an explosives manufacturing facility in Lincoln, CA. Provided interface between owners and consultants. Reviewed site assessments, work plans, closure plans, and RI/FSs.
- Consultant to owner of large western molybdenum mine proposed for NPL listing. Participated in negotiations to scope out consent order and develop scope of work. Participated in studies to determine premining groundwater background to evaluate applicability of water quality standards. Served on technical committees to develop alternatives to mitigate impacts and close the facility, including resloping and grading, various thickness and types of covers, and reclamation. This work included developing and evaluating methods to control surface runoff and erosion, mitigate impacts of acid rock drainage on surface and ground waters, and stabilize nine waste rock piles containing 328 million tons of pyrite-rich, mixed volcanic waste rock (andesites, rhyolite, tuff). Evaluated stability of waste rock piles. Represented client in hearings and meetings with state and federal oversight agencies.

REGULATORY (PARTIAL LIST)

- In January 2014, prepared cost effectiveness analysis for SCR for a 500-MW coal fire power plant, to address unpermitted upgrades in 2000.
- In January 2014, prepared comments on Revised Final Environmental Impact Report for the Phillips 66 Propane Recovery Project.
- In December 2014, prepared "Report on Bakersfield Crude Terminal Permits to Operate."
- In December 2014, prepared comments on Revised Draft Environmental Impact Report for the Phillips 66 Propane Recovery Project.
- In November 2014, prepared comments on Revised Draft Environmental Impact Report for Phillips 66 Rail Spur Extension Project and Crude Unloading Project, Santa Maria, CA to allow the import of tar sands crudes.
- In November 2014, prepared comments on Draft Environmental Impact Report for Phillips 66 Ultra Low Sulfur Diesel Project, responding to the California Supreme Court Decision, *Communities for a Better Environment v. South Coast Air Quality Management Dist. (2010) 48 Cal.4th 310*.

- In November 2014, prepared comments on Draft Environmental Impact Report for the Tesoro Avon Marine Oil Terminal Lease Consideration.
- In October 2014, prepared: "Report on Hydrogen Cyanide Emissions from Fluid Catalytic Cracking Units", pursuant to the Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards, 79 FR 36880.
- In October 2014, prepared technical comments on Final Environmental Impact Reports for Alon Bakersfield Crude Flexibility Project to build a rail terminal to allow the import/export of tar sands and Bakken crude oils and to upgrade an existing refinery to allow it to process a wide range of crudes.
- In October 2014, prepared technical comments on the Title V Permit Renewal and three De Minimus Significant Revisions for the Tesoro Logistics Marine Terminal in the SCAQMD.
- In August 2014, for EPA Region 6, prepared technical report on costing methods for upgrades to existing scrubbers at coal-fired power plants.
- In July 2014, prepared technical comments on Draft Final Environmental Impact Reports for Alon Bakersfield Crude Flexibility Project to build a rail terminal to allow the import/export of tar sands and Bakken crude oils and to upgrade an existing refinery to allow it to process a wide range of crudes.
- In June 2014, prepared technical report on Initial Study and Draft Negative Declaration for the Tesoro Logistics Storage Tank Replacement and Modification Project.
- In May 2014, prepared technical comments on Intent to Approve a new refinery and petroleum transloading operation in Utah.
- In March and April 2014, prepared declarations on air permits issued for two crude-by-rail terminals in California, modified to switch from importing ethanol to importing Bakken crude oils by rail and transferring to tanker cars. Permits were issued without undergoing CEQA review. One permit was upheld by the San Francisco Superior Court as statute of limitations had run. The Sacramento Air Quality Management District withdrew the second one due to failure to require BACT and conduct CEQA review.
- In March 2014, prepared technical report on Negative Declaration for a proposed modification of the air permit for a bulk petroleum and storage terminal to the allow the import of tar sands and Bakken crude oil by rail and its export by barge, under the New York State Environmental Quality Review Act (SEQRA).
- In February 2014, prepared technical report on proposed modification of air permit for midwest refinery upgrade/expansion to process tar sands crudes.
- In January 2014, prepared cost estimates to capture, transport, and use CO2 in enhanced oil recovery, from the Freeport LNG project based on both Selexol and Amine systems.

- In January 2014, prepared technical report on Draft Environmental Impact Report for Phillips 66 Rail Spur Extension Project, Santa Maria, CA. Comments addressed project description (piecemealing, crude slate), risk of upset analyses, mitigation measures, alternative analyses and cumulative impacts.
- In November 2013, prepared technical report on3333 the Phillips 66 Propane Recovery Project, Rodeo, CA. Comments addressed project description (piecemealing, crude slate) and air quality impacts.
- In September 2013, prepared technical report on the Draft Authority to Construct Permit for the Casa Diablo IV Geothermal Development Project Environmental Impact Report and Declaration in Support of Appeal and Petition for Stay, U.S. Department of the Interior, Board of Land Appeals, Appeal of Decision Record for the Casa Diablo IV Geothermal Development Project.
- In September 2013, prepared technical report on Effluent Limitation Guidelines for Best Available Technology Economically Available (BAT) for Bottom Ash Transport Waters from Coal-Fired Power Plants in the Steam Electric Power Generating Point Source Category.
- In July 2013, prepared technical report on Initial Study/Mitigated Negative Declaration for the Valero Crude by Rail Project, Benicia, California, Use Permit Application 12PLN-00063.
- In July 2013, prepared technical report on fugitive particulate matter emissions from coal train staging at the proposed Coyote Island Terminal, Oregon, for draft Permit No. 25-0015-ST-01.
- In July 2013, prepared technical comments on air quality impacts of the Finger Lakes LPG Storage Facility as reported in various Environmental Impact Statements.
- In July 2013, prepared technical comments on proposed Greenhouse Gas PSD Permit for the Celanese Clear Lake Plant, including cost analysis of CO2 capture, transport, and sequestration.
- In June/July 2013, prepared technical comments on proposed Draft PSD Preconstruction Permit for Greenhouse Gas Emission for the ExxonMobil Chemical Company Baytown Olefins Plant, including cost analysis of CO2 capture, transport, and sequestration.
- In June 2013, prepared technical report on a Mitigated Negative Declaration for a new rail terminal at the Valero Benicia Refinery to import increased amounts of "North American" crudes. Comments addressed air quality impacts of refining increased amounts of tar sands crudes.
- In June 2013, prepared technical report on Draft Environmental Impact Report for the California Ethanol and Power Imperial Valley 1 Project.

- In May 2013, prepared comments on draft PSD permit for major expansion of midwest refinery to process 100% tar sands crudes, including a complex netting analysis involving debottlenecking, piecemealing, and BACT analyses.
- In April 2013, prepared technical report on the Draft Supplemental Environmental Impact Statement (DSEIS) for the Keystone XL Pipeline on air quality impacts from refining increased amount of tar sands crudes at Refineries in PADD 3.
- In October 2012, prepared technical report on the Environmental Review for the Coyote Island Terminal Dock at the Port of Morrow on fugitive particulate matter emissions.
- In October 2012-October 2014, review and evaluate Flint Hills West Application for an expansion/modification for increased (Texas, Eagle Ford Shale) crude processing and related modification, including netting and BACT analysis. Assist in settlement discussions.
- Prepared cost analyses and comments on New York's proposed BART determinations for NOx, SO2, and PM and EPA's proposed approval of BART determinations for Danskammer Generating Station under New York Regional Haze State Implementation Plan and Federal Implementation Plan, 77 FR 51915 (August 28, 2012).
- Prepared cost analyses and comments on NOx BART determinations for Regional Haze State Implementation Plan for State of Nevada, 77 FR 23191 (April 18, 2012) and 77 FR 25660 (May 1, 2012).
- Prepared analyses of and comments on New Source Performance Standards for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 FR 22392 (April 13, 2012).
- Prepared comments on CASPR-BART emission equivalency and NOx and PM BART determinations in EPA proposed approval of State Implementation Plan for Pennsylvania Regional Haze Implementation Plan, 77 FR 3984 (January 26, 2012).
- Prepared comments and statistical analyses on hazardous air pollutants (HAPs) emission controls, monitoring, compliance methods, and the use of surrogates for acid gases, organic HAPs, and metallic HAPs for proposed National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units, 76 FR 24976 (May 3, 2011).
- Prepared cost analyses and comments on NOx BART determinations and emission reductions for proposed Federal Implementation Plan for Four Corners Power Plant, 75 FR 64221 (October 19, 2010).
- Prepared cost analyses and comments on NOx BART determinations for Colstrip Units 1- 4 for Montana State Implementation Plan and Regional Haze Federal Implementation Plan, 77 FR 23988 (April 20, 2010).

- For EPA Region 8, prepared report: Revised BART Cost Effectiveness Analysis for Tail-End Selective Catalytic Reduction at the Basin Electric Power Cooperative Leland Olds Station Unit 2 Final Report, March 2011, in support of 76 FR 58570 (Sept. 21, 2011).
- For EPA Region 6, prepared report: Revised BART Cost-Effectiveness Analysis for Selective Catalytic Reduction at the Public Service Company of New Mexico San Juan Generating Station, November 2010, in support of 76 FR 52388 (Aug. 22, 2011).
- For EPA Region 6, prepared report: Revised BART Cost-Effectiveness Analysis for Flue Gas Desulfurization at Coal-Fired Electric Generating Units in Oklahoma: Sooner Units 1 & 2, Muskogee Units 4 & 5, Northeastern Units 3 &4, October 2010, in support of 76 FR 16168 (March 26, 2011). My work was upheld in: *State of Oklahoma v. EPA*, App. Case 12-9526 (10th Cri. July 19, 2013).
- Identified errors in N_2O emission factors in the Mandatory Greenhouse Gas Reporting Rule, 40 CFR 98, and prepared technical analysis to support Petition for Rulemaking to Correct Emissions Factors in the Mandatory Greenhouse Gas Reporting Rule, filed with EPA on 10/28/10.
- Assisted interested parties develop input for and prepare comments on the Information Collection Request for Petroleum Refinery Sector NSPS and NESHAP Residual Risk and Technology Review, 75 FR 60107 (9/29/10).
- Technical reviewer of EPA's "Emission Estimation Protocol for Petroleum Refineries," posted for public comments on CHIEF on 12/23/09, prepared in response to the City of Houston's petition under the Data Quality Act (March 2010).
- Prepared comments on SCR cost effectiveness for EPA's Advanced Notice of Proposed Rulemaking, Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station, 74 FR 44313 (August 28, 2009).
- Prepared comments on Proposed Rule for Standards of Performance for Coal Preparation and Processing Plants, 74 FR 25304 (May 27, 2009).
- Prepared comments on draft PSD permit for major expansion of midwest refinery to process up to 100% tar sands crudes. Participated in development of monitoring and controls to mitigate impacts and in negotiating a Consent Decree to settle claims in 2008.
- Reviewed and assisted interested parties prepare comments on proposed Kentucky air toxic regulations at 401 KAR 64:005, 64:010, 64:020, and 64:030 (June 2007).
- Prepared comments on proposed Standards of Performance for Electric Utility Steam Generating Units and Small Industrial-Commercial-Industrial Steam Generating Units, 70 FR 9706 (February 28, 2005).

- Prepared comments on Louisville Air Pollution Control District proposed Strategic Toxic Air Reduction regulations.
- Prepared comments and analysis of BAAQMD Regulation, Rule 11, Flare Monitoring at Petroleum Refineries.
- Prepared comments on Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electricity Utility Steam Generating Units (MACT standards for coal-fired power plants).
- Prepared Authority to Construct Permit for remediation of a large petroleum-contaminated site on the California Central Coast. Negotiated conditions with agencies and secured permits.
- Prepared Authority to Construct Permit for remediation of a former oil field on the California Central Coast. Participated in negotiations with agencies and secured permits.
- Prepared and/or reviewed hundreds of environmental permits, including NPDES, UIC, Stormwater, Authority to Construct, Prevention of Significant Deterioration, Nonattainment New Source Review, Title V, and RCRA, among others.
- Participated in the development of the CARB document, *Guidance for Power Plant Siting and Best Available Control Technology*, including attending public workshops and filing technical comments.
- Performed data analyses in support of adoption of emergency power restoration standards by the California Public Utilities Commission for "major" power outages, where major is an outage that simultaneously affects 10% of the customer base.
- Drafted portions of the Good Neighbor Ordinance to grant Contra Costa County greater authority over safety of local industry, particularly chemical plants and refineries.
- Participated in drafting BAAQMD Regulation 8, Rule 28, Pressure Relief Devices, including participation in public workshops, review of staff reports, draft rules and other technical materials, preparation of technical comments on staff proposals, research on availability and costs of methods to control PRV releases, and negotiations with staff.
- Participated in amending BAAQMD Regulation 8, Rule 18, Valves and Connectors, including participation in public workshops, review of staff reports, proposed rules and other supporting technical material, preparation of technical comments on staff proposals, research on availability and cost of low-leak technology, and negotiations with staff.
- Participated in amending BAAQMD Regulation 8, Rule 25, Pumps and Compressors, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak and seal-less technology, and negotiations with staff.

- Participated in amending BAAQMD Regulation 8, Rule 5, Storage of Organic Liquids, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of controlling tank emissions, and presentation of testimony before the Board.
- Participated in amending BAAQMD Regulation 8, Rule 18, Valves and Connectors at Petroleum Refinery Complexes, including participation in public workshops, review of staff reports, proposed rules and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak technology, and presentation of testimony before the Board.
- Participated in amending BAAQMD Regulation 8, Rule 22, Valves and Flanges at Chemical Plants, etc, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak technology, and presentation of testimony before the Board.
- Participated in amending BAAQMD Regulation 8, Rule 25, Pump and Compressor Seals, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability of low-leak technology, and presentation of testimony before the Board.
- Participated in the development of the BAAQMD Regulation 2, Rule 5, Toxics, including participation in public workshops, review of staff proposals, and preparation of technical comments.
- Participated in the development of SCAQMD Rule 1402, Control of Toxic Air Contaminants from Existing Sources, and proposed amendments to Rule 1401, New Source Review of Toxic Air Contaminants, in 1993, including review of staff proposals and preparation of technical comments on same.
- Participated in the development of the Sunnyvale Ordinance to Regulate the Storage, Use and Handling of Toxic Gas, which was designed to provide engineering controls for gases that are not otherwise regulated by the Uniform Fire Code.
- Participated in the drafting of the Statewide Water Quality Control Plans for Inland Surface Waters and Enclosed Bays and Estuaries, including participation in workshops, review of draft plans, preparation of technical comments on draft plans, and presentation of testimony before the SWRCB.
- Participated in developing Se permit effluent limitations for the five Bay Area refineries, including review of staff proposals, statistical analyses of Se effluent data, review of literature on aquatic toxicity of Se, preparation of technical comments on several staff proposals, and presentation of testimony before the Bay Area RWQCB.

- Represented the California Department of Water Resources in the 1991 Bay-Delta Hearings before the State Water Resources Control Board, presenting sworn expert testimony with cross examination and rebuttal on a striped bass model developed by the California Department of Fish and Game.
- Represented the State Water Contractors in the 1987 Bay-Delta Hearings before the State Water Resources Control Board, presenting sworn expert testimony with cross examination and rebuttal on natural flows, historical salinity trends in San Francisco Bay, Delta outflow, and hydrodynamics of the South Bay.
- Represented interveners in the licensing of over 20 natural-gas-fired power plants and one coal gasification plant at the California Energy Commission and elsewhere. Reviewed and prepared technical comments on applications for certification, preliminary staff assessments, final staff assessments, preliminary determinations of compliance, final determinations of compliance, and prevention of significant deterioration permits in the areas of air quality, water supply, water quality, biology, public health, worker safety, transportation, site contamination, cooling systems, and hazardous materials. Presented written and oral testimony in evidentiary hearings with cross examination and rebuttal. Participated in technical workshops.
- Represented several parties in the proposed merger of San Diego Gas & Electric and Southern California Edison. Prepared independent technical analyses on health risks, air quality, and water quality. Presented written and oral testimony before the Public Utilities Commission administrative law judge with cross examination and rebuttal.
- Represented a PRP in negotiations with local health and other agencies to establish impact of subsurface contamination on overlying residential properties. Reviewed health studies prepared by agency consultants and worked with agencies and their consultants to evaluate health risks.

WATER QUALITY/RESOURCES

- Directed and participated in research on environmental impacts of energy development in the Colorado River Basin, including contamination of surface and subsurface waters and modeling of flow and chemical transport through fractured aquifers.
- Played a major role in Northern California water resource planning studies since the early 1970s. Prepared portions of the Basin Plans for the Sacramento, San Joaquin, and Delta basins including sections on water supply, water quality, beneficial uses, waste load allocation, and agricultural drainage. Developed water quality models for the Sacramento and San Joaquin Rivers.
- Conducted hundreds of studies over the past 40 years on Delta water supplies and the impacts of exports from the Delta on water quality and biological resources of the Central Valley, Sacramento-San Joaquin Delta, and San Francisco Bay. Typical examples include:

1. Evaluate historical trends in salinity, temperature, and flow in San Francisco Bay and upstream rivers to determine impacts of water exports on the estuary;
2. Evaluate the role of exports and natural factors on the food web by exploring the relationship between salinity and primary productivity in San Francisco Bay, upstream rivers, and ocean;
3. Evaluate the effects of exports, other in-Delta, and upstream factors on the abundance of salmon and striped bass;
4. Review and critique agency fishery models that link water exports with the abundance of striped bass and salmon;
5. Develop a model based on GLMs to estimate the relative impact of exports, water facility operating variables, tidal phase, salinity, temperature, and other variables on the survival of salmon smolts as they migrate through the Delta;
6. Reconstruct the natural hydrology of the Central Valley using water balances, vegetation mapping, reservoir operation models to simulate flood basins, precipitation records, tree ring research, and historical research;
7. Evaluate the relationship between biological indicators of estuary health and down-estuary position of a salinity surrogate (X2);
8. Use real-time fisheries monitoring data to quantify impact of exports on fish migration;
9. Refine/develop statistical theory of autocorrelation and use to assess strength of relationships between biological and flow variables;
10. Collect, compile, and analyze water quality and toxicity data for surface waters in the Central Valley to assess the role of water quality in fishery declines;
11. Assess mitigation measures, including habitat restoration and changes in water project operation, to minimize fishery impacts;
12. Evaluate the impact of unscreened agricultural water diversions on abundance of larval fish;
13. Prepare and present testimony on the impacts of water resources development on Bay hydrodynamics, salinity, and temperature in water rights hearings;
14. Evaluate the impact of boat wakes on shallow water habitat, including interpretation of historical aerial photographs;
15. Evaluate the hydrodynamic and water quality impacts of converting Delta islands into reservoirs;

16. Use a hydrodynamic model to simulate the distribution of larval fish in a tidally influenced estuary;
17. Identify and evaluate non-export factors that may have contributed to fishery declines, including predation, shifts in oceanic conditions, aquatic toxicity from pesticides and mining wastes, salinity intrusion from channel dredging, loss of riparian and marsh habitat, sedimentation from upstream land alternations, and changes in dissolved oxygen, flow, and temperature below dams.

- Developed, directed, and participated in a broad-based research program on environmental issues and control technology for energy industries including petroleum, oil shale, coal mining, and coal slurry transport. Research included evaluation of air and water pollution, development of novel, low-cost technology to treat and dispose of wastes, and development and application of geohydrologic models to evaluate subsurface contamination from in-situ retorting. The program consisted of government and industry contracts and employed 45 technical and administrative personnel.
- Coordinated an industry task force established to investigate the occurrence, causes, and solutions for corrosion/erosion and mechanical/engineering failures in the waterside systems (e.g., condensers, steam generation equipment) of power plants. Corrosion/erosion failures caused by water and steam contamination that were investigated included waterside corrosion caused by poor microbiological treatment of cooling water, steam-side corrosion caused by ammonia-oxygen attack of copper alloys, stress-corrosion cracking of copper alloys in the air cooling sections of condensers, tube sheet leaks, oxygen in-leakage through condensers, volatilization of silica in boilers and carry over and deposition on turbine blades, and iron corrosion on boiler tube walls. Mechanical/engineering failures investigated included: steam impingement attack on the steam side of condenser tubes, tube-to-tube-sheet joint leakage, flow-induced vibration, structural design problems, and mechanical failures due to stresses induced by shutdown, startup and cycling duty, among others. Worked with electric utility plant owners/operators, condenser and boiler vendors, and architect/engineers to collect data to document the occurrence of and causes for these problems, prepared reports summarizing the investigations, and presented the results and participated on a committee of industry experts tasked with identifying solutions to prevent condenser failures.
- Evaluated the cost effectiveness and technical feasibility of using dry cooling and parallel dry-wet cooling to reduce water demands of several large natural-gas fired power plants in California and Arizona.
- Designed and prepared cost estimates for several dry cooling systems (e.g., fin fan heat exchangers) used in chemical plants and refineries.
- Designed, evaluated, and costed several zero liquid discharge systems for power plants.

- Evaluated the impact of agricultural and mining practices on surface water quality of Central Valley steams. Represented municipal water agencies on several federal and state advisory committees tasked with gathering and assessing relevant technical information, developing work plans, and providing oversight of technical work to investigate toxicity issues in the watershed.

AIR QUALITY/PUBLIC HEALTH

- Prepared or reviewed the air quality and public health sections of hundreds of EIRs and EISs on a wide range of industrial, commercial and residential projects.
- Prepared or reviewed hundreds of NSR and PSD permits for a wide range of industrial facilities.
- Designed, implemented, and directed a 2-year-long community air quality monitoring program to assure that residents downwind of a petroleum-contaminated site were not impacted during remediation of petroleum-contaminated soils. The program included real-time monitoring of particulates, diesel exhaust, and BTEX and time integrated monitoring for over 100 chemicals.
- Designed, implemented, and directed a 5-year long source, industrial hygiene, and ambient monitoring program to characterize air emissions, employee exposure, and downwind environmental impacts of a first-generation shale oil plant. The program included stack monitoring of heaters, boilers, incinerators, sulfur recovery units, rock crushers, API separator vents, and wastewater pond fugitives for arsenic, cadmium, chlorine, chromium, mercury, 15 organic indicators (e.g., quinoline, pyrrole, benzo(a)pyrene, thiophene, benzene), sulfur gases, hydrogen cyanide, and ammonia. In many cases, new methods had to be developed or existing methods modified to accommodate the complex matrices of shale plant gases.
- Conducted investigations on the impact of diesel exhaust from truck traffic from a wide range of facilities including mines, large retail centers, light industrial uses, and sports facilities. Conducted traffic surveys, continuously monitored diesel exhaust using an aethalometer, and prepared health risk assessments using resulting data.
- Conducted indoor air quality investigations to assess exposure to natural gas leaks, pesticides, molds and fungi, soil gas from subsurface contamination, and outgasing of carpets, drapes, furniture and construction materials. Prepared health risk assessments using collected data.
- Prepared health risk assessments, emission inventories, air quality analyses, and assisted in the permitting of over 70 1 to 2 MW emergency diesel generators.
- Prepare over 100 health risk assessments, endangerment assessments, and other health-based studies for a wide range of industrial facilities.

- Developed methods to monitor trace elements in gas streams, including a continuous real-time monitor based on the Zeeman atomic absorption spectrometer, to continuously measure mercury and other elements.
- Performed nuisance investigations (odor, noise, dust, smoke, indoor air quality, soil contamination) for businesses, industrial facilities, and residences located proximate to and downwind of pollution sources.

PUBLICATIONS AND PRESENTATIONS (Partial List - Representative Publications)

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Pesticides in the TIE Process, SETAC, 6/96
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Design of Gas Turbine Combined Cycle and Cogeneration Systems, Thermoflow, 12/00
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McIlvaine Hot Topic Hour, Mercury Control, 4/24/08
McIlvaine Hot Topic Hour, Co-Firing Biomass, 5/1/08
McIlvaine Hot Topic Hour, Coal Gasification, 6/5/08
McIlvaine Hot Topic Hour, Spray Driers vs. CFBs, 7/3/08
McIlvaine Hot Topic Hour, Air Pollution Control Cost Escalation, 9/25/08
McIlvaine Hot Topic Hour, Greenhouse Gas Strategies for Coal Fired Power Plant Operators, 10/2/08
McIlvaine Hot Topic Hour, Mercury and Toxics Monitoring, 2/5/09
McIlvaine Hot Topic Hour, Dry Precipitator Efficiency Improvements, 2/12/09
McIlvaine Hot Topic Hour, Coal Selection & Impact on Emissions, 2/26/09
McIlvaine Hot Topic Hour, 98% Limestone Scrubber Efficiency, 7/9/09
McIlvaine Hot Topic Hour, Carbon Management Strategies and Technologies, 6/24/10
McIlvaine Hot Topic Hour, Gas Turbine O&M, 7/22/10

McIlvaine Hot Topic Hour, Industrial Boiler MACT – Impact and Control Options, March 10, 2011

McIlvaine Hot Topic Hour, Fuel Impacts on SCR Catalysts, June 30, 2011.
Interest Rates, PDH P204, 3/9/12
Mechanics Liens, PDHOnline, 2/24/13.
Understanding Concerns with Dry Sorbent Injection as a Coal Plant Pollution Control, Webinar #874-567-839 by Cleanenergy.Org, March 4, 2013
Webinar: Coal-to-Gas Switching: What You Need to Know to Make the Investment, sponsored by PennWell Power Engineering Magazine, March 14, 2013. Available at: https://event.webcasts.com/viewer/event.jsp?ei=1013472.

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OFFICE OF ENVIRONMENTAL SERVICES

PUBLIC COMMENTS RESPONSE SUMMARY

PART 70 OPERATING PERMIT 2560-00295-V0

YCI METHANOL PLANT
YUHUANG CHEMICAL INC.
ST. JAMES, ST. JAMES PARISH, LOUISIANA
Agency Interest No. 194165

This document responds to pertinent statements (questions and/or comments) received via mail, e-mail, and at the public hearing on the permit action referenced above. Comments reflected herein are taken verbatim from the written submittals and public hearing transcript.[1]

A notice requesting public comment and announcing a public hearing on the proposed permit was published in *The Advocate*, Baton Rouge; and in the *News Examiner*, Lutcher, on February 4, 2015. Copies of the public notice were also mailed to the individuals who have requested to be placed on the mailing list maintained by the Office of Environmental Services (OES) on January 29, 2015. The proposed permit was also submitted to the United States Environmental Protection Agency (EPA) on February 4, 2015.

A public hearing was held on Thursday, March 12, 2015, at the St. James Reception Hall, 2455 Highway 18, Vacherie, Louisiana. The comment period closed on March 16, 2015.

During the comment period, the proposed permit, Statement of Basis, permit application, additional information, and Environmental Assessment Statement (EAS) were available for review at LDEQ's Public Records Center (Room 127), 602 North 5th Street, Baton Rouge, Louisiana; and at the St. James Parish Library – Vacherie Branch, 2593 Highway 20, Vacherie, Louisiana. These documents were also accessible through LDEQ's Electronic Document Management System (EDMS).[2]

Comment No. 1 [3]

EQT 0001: Steam Methane Reformer (SMR)

The terms and conditions contained in a Title V permit must assure compliance with all applicable requirements and that the limits are practically enforceable. There appear to be limitations on maximum and average firing rate listed in the 'Inventories' table of the draft permit that do not appear to have any corresponding monitoring or recordkeeping associated with the values, yet this source is relying on control technology to achieve synthetic minor status and avoid PSD review. Either provide associated monitoring and recordkeeping or describe why not in required.

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[1] "Ya'll" in the public hearing transcript has been rendered "y'all" in this Public Comments Response Summary.

[2] LDEQ's EDMS is the electronic repository of official records that have been created or received by LDEQ. Members of the public can search and retrieve documents stored in EDMS via the internet at http://edms.deq.louisiana.gov.

[3] Comment nos. 1 – 6 were submitted by Mr. Jeff Robinson of the U.S. Environmental Protection Agency, Region 6 (EDMS Doc ID 9675108).

LDEQ Response to Comment No. 1

Because the ton per year limitations for the SMR are based on the "normal" operating rate and not the maximum operating rate as represented in the "Inventories" section of proposed Permit No. 2560-00295-V0, LDEQ added a condition to the permit requiring the amount of fuel combusted by this unit to be monitored and recorded.

Comment No. 2

> **EQT 0001: Steam Methane Reformer (SMR)**
>
> There appears to be no initial demonstration of compliance for NOx from the SMR, yet the SMR is relying on selective catalytic reforming to achieve and maintain the NOx limitations. Please provide for an initial and recurring demonstration of compliance (stack test).

LDEQ Response to Comment No. 2

Proposed Specific Requirement 41 (repeated below) requires NO_X emissions from the SMR to be monitored and recorded using a continuous emissions monitoring system (CEMS).

> The permittee shall monitor and record NOx emissions a using Continuous Emissions Monitoring System (CEMS) calibrated, operated, and maintained according to the manufacturer's specifications. The CEMS shall comply with Performance Specification 2 of 40 CFR 60, Appendix B, and be evaluated in accordance with Procedure 1 of 40 CFR 60, Appendix F. Data availability shall be dictated by Part 70 General Condition V of LAC 33:III.535.A. [LAC 33:III.507.H.1.a]

Comment No. 3

> **EQT 0001: Steam Methane Reformer (SMR) and EQT 0002: Auxiliary Boiler (BLR)**
>
> The calculations of the annual emission limitation for EPNs 0001 and 0002 appear to rely on the continuous use of selective catalytic reduction (SCR) to control NOx emissions to rates below PSD review level. Please include a federally enforceable permit limitation to require the use of SCR for the emissions from EPNs 0001 and 0002, and the associated testing, monitoring, recordkeeping, and reporting requirements or provide the rationale why such a [*sic*] conditions are unnecessary.

LDEQ Response to Comment No. 3

LDEQ added conditions to Permit No. 2560-00295-V0 requiring NO_X emissions from the SMR and auxiliary boiler (BLR) to be controlled via selective catalytic reduction (SCR).

As noted in LDEQ Response to Comment No. 2, the SMR will be equipped with a NO_X CEMS. With respect to the BLR, a NO_X CEMS is required by 40 CFR 60.48b(b)(1) of Subpart Db and is addressed by proposed Specific Requirement 47, which reads as follows:

> Install, calibrate, maintain, and operate CEMS for measuring NOx and O2 (or CO2) emissions discharged to the atmosphere, and shall record the output of the system. The CEMS shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments. The 1-hour average NOx emission rates shall be expressed in lb/MM Btu heat input and shall be used to calculate the average emission rates under 40 CFR 60.44b. The 1-hour averages shall be calculated using the data points required under 40 CFR 60.13(h)(2). [40 CFR 60.48b(b)(1),(c-d)]

NO_X emissions from the SMR and BLR must be reported per LAC 33:III.919 (Emissions Inventory).[4] For the BLR, reporting is also required by 40 CFR 60.49b(i) of Subpart Db.[5]

Comment No. 4

> **EQT 0001: Steam Methane Reformer (SMR) and EQT 0002: Auxiliary Boiler (BLR)**
>
> The emission factors for NOx (0.01 lb NOx/MMBtu when the SCR is operational, and 0.04 lb/MMBtu when it is not) is apparently relied upon in the establishment of the short and long term emissions yet there is no monitoring, testing, recordkeeping or reporting provisions apparently provided that can support compliance with this representation. Please provide the supporting requirements or explain why they are unnecessary.

LDEQ Response to Comment No. 4

EPA is correct in that the hourly and annual NO_X limitations are based on emission factors of 0.01 lb/MM Btu and 0.04 lb/MM Btu. However, these factors are not included as limitations in Permit No. 2560-00295-V0 because there are no underlying federal or state standards restricting NO_X emissions per unit of heat input to these values. Because the NO_X CEMS can assure compliance with both the pound per hour and ton per year NO_X limits included in the permit, no additional monitoring, recordkeeping, and reporting provisions are necessary.

Comment No. 5

> **EQT 0003: Flare (FLR)**
>
> 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 [*sic*] the permit.

LDEQ Response to Comment No. 5

40 CFR 60.18 applies to "control devices used to comply with applicable subparts of 40 CFR parts 60 and 61." During normal operations, the flare will not be used to control emissions from distillation operations subject to 40 CFR 60 Subpart NNN, reactor processes subject to 40 CFR 60 Subpart RRR, or components subject to 40 CFR 60 Subpart VVa.

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[4] Proposed Specific Requirement 288
[5] Proposed Specific Requirement 54

The flare will be used to control emissions from distillation operations and/or reactor processes during periods of startup, shutdown, and malfunction; however, during such periods, the flare would not function as a control device "used to comply with applicable subparts of 40 CFR parts 60 and 61." 40 CFR 60.8(c) reads, in relevant part:

> [N]or shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

Section XI, Table 2 of Permit No. 2560-00295-V0 will be amended to clarify the applicability of 40 CFR 60.18.

Comment No. 6

> **Sufficiency of the record**
>
> There were numerous references to information regarding the establishment of emissions factors were available neither in the permit application record nor in a location generally accessible for review. For example, the column entitled "Emissions Factor Source, Notes" associated with the SMR and BLR both contain the note "0.01 lb/MMBtu factor based on HHV and provided by Air Liquide on 9/25/14 "69919-PR-00038 Air Permit Data Rev 0.1 xlsx" but the referenced spreadsheet was not provided. Please provide the referenced spreadsheet and make it available in the permit public record, consistent with applicable requirements related to permit application contents.

LDEQ Response to Comment No. 6

Consistent with 40 CFR 70.5(c)(3)(viii),[6] the application contains the calculations on which the "emission-related information" described in 40 CFR 70.5(c)(3)(i)-(vii) is based and is "sufficient to evaluate the subject source and … to determine all applicable requirements."[7]

The references to "69919-PR-00038 Air Permit Data Rev. 01.xlsx" were used by Environ to document the *origin* of the inputs used in the emissions calculations (e.g., the firing rate of the steam methane reformer, the stack flow rate, and the maximum percentage of methanol in the streams). The inputs themselves are disclosed in the application and were provided by the supplier of the technology – Air Liquide.

Comment No. 7

> [W]e have a concern about the quality of life that you're gonna' maintain once this facility is completed; because I see where y'all speak about the jobs that it's gonna' prepare – it's gonna' have; but when I travel up and down the highway, I can see cars from Texas, and Mississippi; I don't see any cars going into the any of these job locations from Louisiana; and I'm not convinced that this facility will be any different.[8]

* * *

[6] 40 CFR 70.5(a)(2)

[7] See also LAC 33:III.517.D.9.

[8] Oral comments of Ms. Caroline Favorite (EDMS Doc ID 9694708, p. 46 of 87). Note that Ms. Favorite is identified as Ms. Caroline Farve in the public hearing transcript.

> And, also, I heard other people saying things about, maybe, some jobs or something coming into the parish; but however, if the jobs are not gonna' benefit us, then we don't need the plant.[9]
>
> * * *
>
> We are being promise [*sic*] jobs and everything else in the Community, too many times have I heard this over and over and we never get anything, maybe one or two jobs. Once the Company gets all their Permits, they forget about what they talked about.[10]

LDEQ Response to Comment No. 7

According to the Environmental Assessment Statement (EAS), "[u]p to approximately 2,000 temporary construction jobs could be generated during the peak construction phase of the project, with construction extending over approximately two years. Construction workers are anticipated to reside locally or within the surrounding region."[11] The EAS also states that "[o]peration of the Methanol Plant is projected to require approximately 200 workers. Accordingly, YCI sought to locate the facility within a reasonable commute of the more highly populated areas that could provide a pool of skilled industrial workers."[12] In addition, at the public hearing on the proposed permit, Mr. Charlie Yao, president and CEO of Yuhuang Chemical Inc., expressed his desire to make "local hires."[13]

Comment No. 8

> [W]e just want to make sure that, whatever this plant does, is not gonna' cause any health conditions; because we have enough health conditions as it is already.[14]
>
> * * *
>
> [W]e're concerned about what the long-term effect will be; I have heard no one but the last gentleman who spoke; and when he spoke, he spoke about people; he talk about lives.
>
> We're talking about lives; he was the only gentleman I heard who spoke; and he spoke well; and I agree with him; we need to think; of course we would love the plant to move in, if it's beneficial not just for financial-wise, but health-wise. Because so what if we making money, and you can't enjoy it?
>
> What if you giving the children different benefits, and nobody will get to enjoy them because of health-wise effect? We live less than a half a mile from where this plant is coming up; I live at Barras Street, not too far from St. James Post Office; not too far from St. James High School.[15]
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> * * *

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[9] Oral comments of Ms. Janel Gordon (EDMS Doc ID 9694708, p. 56 of 87)
[10] Comments of Mr. Charles "I Spy" Ketchens, District 5 Councilman, St. James Parish Council (EDMS Doc ID 9675106)
[11] EAS, p. D-4 (EDMS Doc ID 9527280, p. 183 of 186)
[12] EAS, p. D-7 (EDMS Doc ID 9527280, p. 186 of 186)
[13] Oral comments of Mr. Charlie Yao (EDMS Doc ID 9694708, p. 35 of 87)
[14] Oral comments of Ms. Janel Gordon (EDMS Doc ID 9694708, p. 56 of 87)
[15] Oral comments of Ms. Lydia Small (EDMS Doc ID 9694708, pp. 52-53 of 87)

The plant come up; but we don't want to be around here, because the cause and effect, if what I'm hearing is correct, that it will cause cancer; there's enough sickness in the area already; and we want to enjoy the life that God has given us, I'm saying.[16]

LDEQ Response to Comment No. 8

The Clean Air Act (Act) required the U.S. Environmental Protection Agency (EPA) to establish health-based national ambient air quality standards (NAAQS) for pollutants considered harmful to public health and the environment. The Act established two types of standards. Primary standards are limits designed to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards are designed to protect public welfare, including protection from decreased visibility and damage to animals, crops, vegetation, and buildings. According to EPA, air quality that adheres to such standards is protective of public health, animals, soils, and vegetation. EPA has set NAAQS for six principal pollutants, called criteria pollutants – particulate matter (PM_{10} and $PM_{2.5}$), sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), ozone, and lead.[17]

At the state level, Louisiana has established unique, risk-based ambient air standards (AAS) for 99 compounds known as toxic air pollutants, or TAPs. TAPs include chemicals such as ammonia and methanol.

As shown in the table below, LDEQ has found that emissions from the YCI Methanol Plant will not cause or contribute to a violation of a NAAQS or AAS; therefore, the permit should not allow for air quality impacts that could adversely affect human health or the environment in St. James or in the surrounding area.

Pollutant	Averaging Period	Modeled Maximum Ground Level Concentration ($\mu g/m^3$)	Significant Impact Level (SIL) [18] ($\mu g/m^3$)	NAAQS or (AAS) ($\mu g/m^3$)
PM_{10}	24-hour	1.02	5	150
$PM_{2.5}$	24-hour	0.77	1.2	35
	Annual	0.08	0.3	12
NO_2	1-hour	2.61	7.5	189
	Annual	0.14	1	100
CO	1-hour	138.80	2000	40,000
	8-hour	104.77	500	10,000
ammonia	8-hour	13.91	N/A	(640.00)
methanol	8-hour	3889.61	N/A	(6240.00)

[16] *Id.* (p. 54 of 87)

[17] Nitrogen oxides (NO_X) and volatile organic compounds (VOC) are regulated in place of ozone.

[18] Per 40 CFR 51.165(b)(2), a proposed source shall not be considered to cause or contribute to a violation of a NAAQS unless such source would, at a minimum, exceed a SIL at a locality that does not or would not meet the applicable standard.

In sum, standards such as the NAAQS and AAS contemplate multiple sources of pollution and establish protective limits on cumulative emissions that should ordinarily prevent adverse air quality impacts.

Comment No. 9

> But we have a concern about the quality of life; and if the railroad track comes behind our house, if that's gonna' be activity all throughout the night, that's a concern for us; and what smells and stuff that we're gonna' have in the area.[19]

LDEQ Response to Comment No. 9

According to EPA, it is difficult to smell methanol in the air at concentrations less than 2000 parts per million,[20] a figure which equates to approximately 2,620,000 micrograms per cubic meter ($\mu g/m^3$).[21] As noted in LDEQ Response to Comment No. 8, the maximum ground level concentration of methanol was modeled to be 3889.61 $\mu g/m^3$, significantly lower than the threshold identified by EPA.

Regarding the railroad, a new loading spur will be constructed to support the YCI Methanol Plant. However, no new rail lines will be constructed in the vicinity of residential areas, and operations of the existing rail line should not be significantly impacted by the new facility.

Comment No. 10

> We really want to know what's going on; and, again, just to find out, you know, they say they bought the school; I just hear things in the air; nothing concrete, you know; the school has been purchased; and we like that the school's been purchased; we didn't know that.[22]

LDEQ Response to Comment No. 10

It has been reported that on March 2, 2015, the St. James Parish School Board accepted Yuhuang's offer to purchase the St. James High School, but the deal is contingent on several factors.[23] However, this matter is outside of the scope of this permit action, and questions or concerns should be directed to the St. James Parish School Board or Yuhuang.

Comment No. 11

> And some people didn't get paid out. How come some people got paid money, and we not supposed to know that? I don't know; we need to know that, too; because we all are citizens here in St. James Parish; it's all right; and we just want to know what's going on.[24]

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[19] Oral comments of Ms. Caroline Favorite (EDMS Doc ID 9694708, pp. 46-47 of 87)
[20] http://www.epa.gov/ttn/atw/hlthef/methanol.html
[21] Conversion assumes temperature of 77°F and 1 atmosphere of pressure.
[22] Oral comments of Ms. Janel Gordon (EDMS Doc ID 9694708, p. 57 of 87)
[23] http://theadvocate.com/news/11742923-123/st-james-school-board-accepts
St. James Parish School Board meeting agendas and other documents are available at http://www.boarddocs.com/la/stjames/Board.nsf/Public.
[24] Oral comments of Ms. Janel Gordon (EDMS Doc ID 9694708, p. 57 of 87)

> I also am saying, I might be incorrect, y'all have said they purchased St. James High School; that's good; that's beautiful. Am I incorrect -- or may I ask: Have the plant, I'm saying, purchased any property of some of the neighbors, I'm saying, around St. James?
>
> Because what I'm concerned, I'm saying, if that's the case, I'm saying, in discrimination, why haven't we had the same trust? Why they could purchase our property that we have to live right here?[25]
>
> * * *
>
> [B]ut if, I'm saying, y'all gonna' come here and purchase the property, because I'm right on the doorstep, y'all say: "Well, let's purchase the property around here"; if you can move 'em here, y'all can move me.[26]

LDEQ Response to Comment No. 11

Neither the Clean Air Act nor the Louisiana Environmental Quality Act compels Yuhuang to purchase adjacent or nearby residential properties. Concerns regarding this matter are outside of the scope of this permit action and should be directed to Yuhuang.

Comment No. 12

> So, we would really appreciate it if we would be aware of all of this; again, I didn't even know about the meeting tonight until I got a call from one of our neighbors; so, whoever's publicizing, I hope they would publicize it a little bit more, so that we can be aware of what's going on.[27]

LDEQ Response to Comment No. 12

A notice requesting public comment and announcing a public hearing on the proposed permit was published in *The Advocate*, Baton Rouge; and in the *News Examiner*, Lutcher, on February 4, 2015. Notice was also provided on LDEQ's "Public Notices" webpage.[28] In addition, copies of the public notice were mailed to the individuals who have requested to be placed on the mailing list maintained by LDEQ's Office of Environmental Services on January 29, 2015. These notices fulfilled the public participation requirements of 40 CFR 70.7(h) and LAC 33:III.531.A.3.

In order to be placed on the mailing list, one should e-mail deq.publicnotices@la.gov or call LDEQ's Customer Service Center at (225) 219-LDEQ (219-5337). LDEQ also offers an electronic notification service.[29]

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[25] Oral comments of Ms. Lydia Small (EDMS Doc ID 9694708, pp. 53-54 of 87)
[26] *Id.* (pp. 54-55 of 87)
[27] Oral comments of Ms. Janel Gordon (EDMS Doc ID 9694708, p. 57 of 87)
[28] http://www.deq.louisiana.gov/apps/pubNotice/default.asp
[29] http://louisiana.gov/Services/Email_Notifications_DEQ_PN

Comment No. 13 [30]

LDEQ Should Reject the Proposed Permit because the EAS Fails to Provide the Information Necessary for the Agency to Perform its Public Trustee Duty.

The Louisiana Environmental Quality Act mandates that "[t]he applicant for a new permit ... that would authorize ... air emissions in sufficient quantity or concentration to constitute a major source [such as this plant] ... shall submit an environmental assessment statement as a part of the permit application." La. Rev. Stat. § 30:2018(A). The Act further provides that "[t]he environmental assessment statement ... shall be used [by LDEQ] to satisfy the public trustee requirements of Article IX, Section 1 of the Constitution of Louisiana." *Id.* at 30:2018(B). And for LDEQ to satisfy the public trustee requirements, it must determine "that adverse environmental impacts have been minimized or avoided as much as possible consistently with the public welfare" before it can issue a final permit. *Save Ourselves, Inc. v. Louisiana Envtl. Control Comm'n* 452 So. 2d 1152, 1157 (interpreting La. Const. Art. IX, § 1) (emphasis added). To make this determination, LDEQ must issue a written permit decision that satisfactorily answers whether:

> (1) the potential and real adverse environmental effects of the proposed project have been avoided to the maximum extent possible; (2) a cost-benefit analysis of the environmental impact costs balanced against the social and economic benefits of the project demonstrate that the latter outweighs the former; and (3) there are no alternative projects or alternative sites or mitigating measures which would offer more protection to the environment than the proposed project without unduly curtailing non-environmental benefits to the extent applicable.

In re Oil & Gas Exploration, Dev., & Prod. Facilities, Permit No. LAG260000, 2010-1640 (La. App. 1 Cir. 6/10/11). Indeed, section 30:2018 specifically requires the permit applicant to address each of these issues in the EAS that it submits to LDEQ. *See* La. Rev. Stat. § 30:2018(B). But, as Commenters detail below, Yuhuang Chemical's EAS fails to adequately address these issues in a meaningful way and therefore LDEQ cannot rely on this EAS – as section 30:2018(B) requires – to make its decision. LDEQ should have required an adequate EAS before issuing a proposed permit decision (as DNR did for this project) but since it did not, it must reject the permit.

LDEQ Response to Comment No. 13

See LDEQ Response to Comment Nos. 14, 15, and 16.

Comment No. 14

The Required Cost-Benefit Analysis is Limited to a Discussion of Benefits and Fails to Demonstrate That These Benefits Outweigh the Environmental Costs.

[30] Unless otherwise noted, comment nos. 13 – 40 were submitted by Ms. Corinne Van Dalen of the Tulane Environmental Law Clinic on behalf of the Sierra Club and Louisiana Environmental Action Network (EDMS Doc IDs 9677371 & 9685416).

Yuhuang Chemical's cost benefit analysis only looks at alleged economic benefits without any consideration of the environmental costs. LDEQ's analysis "requires a balancing process in which environmental costs and benefits must be given full and careful consideration along with economic, social and other factors." *Save Ourselves, Inc. v. Louisiana Envtl. Control Comm'n*, 452 So. 2d 1152, 1157 (La. 1984). But the EAS treats only one side of this balancing process by listing only the putative economic benefits such as direct and indirect job creation. The EAS omits all mention of health risks – which is incredible given the fact that the plant is a *major source of hazardous air pollutants*. A recent study determined that chemical exposure "is likely leading to an increased risk of serious health problems costing at least $175 billion (U.S.) per year in Europe ... 'If you applied these [health care] numbers to the U.S., they would be applicable, and in some cases higher' says [Linda] Birnbaum, director of the U.S. National Institute of Environmental Health Sciences." Adverse health effects are associated with all of the pollutants the facility will emit. *See* Health Effects of Air Pollution, EPA Region 7 Air Program, Ex. D; *see also* EPA Fact Sheets on Hazardous Air Pollutants, Exs. E-I. Yet, Yuhuang failed to consider the costs of the effects on the community. The health costs from the impacts of the hazardous material Yuhuang Chemical proposes to emit must be considered and weighed against the putative economic benefits.

Yuhuang simply concludes that it "believes that the social and economic benefits of the project will outweigh any negative environmental impacts" without providing any assessment of potential environmental costs. LDEQ will abdicate its public trustee duty if it takes Yuhuang Chemical's "beliefs" at face value. LDEQ's "role as the representative of the public interest does not permit it to act as an umpire passively calling balls and strikes ... the rights of the public must receive ***active and affirmative protection***." *Save Ourselves*, 452 So. 2d at 1157 (interpreting La. Const. Art. IX, § 1) (emphasis added). Furthermore, LDEQ should give Yuhuang's statements extra scrutiny given the practices of its parent company, Shandong Yuhuang. In 2013, "Shandong Yuhuang, in Heze, China, *misreported energy efficiency measures*" and "had created unlivable environmental conditions for villagers in the area, with rising cancer rates, undrinkable water and polluted air.'"

* * *

[T]he Company makes no effort to examine the amount of harm that will possibly come from this plant; it only states it will have benefits; and those benefits will outweigh the harms.

Well, in our analysis, we don't see that these benefits will outweigh the harms; and that there are harms that need to be addressed; and the State Department of Environmental Quality needs to, under the IT Act, and other state laws, make sure that these companies are not causing environmental harm on the local community.

And it was interesting, in reading the document, to see where the Company lists all the benefits it's gonna' provide for the parish; but it did not have any list of possible impacts from increased traffic via road; rail; increased emissions.

And, once again, this is part of the IT analysis that the Department of Environmental Quality has to do in any permit, to do a detailed analysis ...[31]

[31] Oral comments of Mr. Darryl Malek-Wiley (EDMS Doc ID 9694708, pp. 49-50 of 87)

LDEQ Response to Comment No. 14

Yuhuang's discussion of the "potential and real adverse environmental effects of the proposed facility" is set forth in Section 2 of its EAS.[32] The EAS also properly focuses on how such impacts will be mitigated.

Contrary to the assertion of the commenter, air emissions do not necessarily result in "adverse health impacts," "health risks," or "health costs." In the present case, Yuhuang demonstrated that the impacts of methanol and ammonia emissions would be well below their respective Louisiana ambient air standards. Further, LDEQ found that emissions from the YCI Methanol Plant will not cause or contribute to a violation of a NAAQS. For these reasons, the proposed facility should not result in air quality impacts that could adversely affect human health or the environment in St. James or in the surrounding area. See LDEQ Response to Comment No. 8.

In sum, LDEQ has found that the social and economic benefits of the proposed facility outweigh its environmental impact costs (see Section VIII of LDEQ's Basis for Decision).

Finally, the commenter alleges that Shandong Yuhuang Chemical Company (SYCC), the Chinese parent of Yuhuang, has a poor record with respect to compliance with environmental laws and regulations. Because the laws and regulations in China clearly differ from those in Louisiana (e.g., as related to monitoring, recordkeeping, and reporting), environmental allegations against SYCC's operations located outside of the United States do not oblige LDEQ to give "extra scrutiny" to Yuhuang's statements. At this time, LDEQ does not believe that Yuhuang is unable or unwilling to comply with the Clean Air Act, the Louisiana Environmental Quality Act, or the applicable federal and state regulations and other requirements set forth in Permit No. 2560-000295-V0.

Comment No. 15

> Yuhuang Chemical Fails to Evaluate Any Alternative Projects or Alternative Sites, It Only Extolls the Putative Benefits of the Selected Site.
>
> LDEQ must show "there are no alternative projects or alternative sites or mitigating measures which would offer more protection to the environment than the proposed project without unduly curtailing non-environmental benefits to the extent applicable." *In re Oil & Gas Exploration,* 809 So. 2d at 238. But Yuhuang Chemical has provided no analysis that would allow LDEQ to determine whether there are alternative projects or sites that are more protective of the environment. Yuhuang Chemical did not even provide quantitative search criteria (i.e., site size, etc.), nor did it provide a list of sites throughout the Gulf region that it claims it considered. Without this information, LDEQ cannot perform its public trustee analysis. For this reason alone, LDEQ must reject the proposed permit.
>
> In less than 200 words, Yuhuang Chemical concludes that it is unaware of any alternative project could meet the project goal. The goal of the project is "to produce commercial grade methanol of (*sic*) sale to domestic and international customers." Yuhuang Chemical highlights their "licensed Air Liquide Lurgi MegaMethanol® technology, a highly efficient process." Yuhuang Chemical also points to the proposed site's access to shipping infrastructure. This cannot be used to satisfy LDEQ's public trustee duty. Yuhuang

[32] EAS, pp. D-1 - D-3 (EDMS Doc ID 9527280, pp. 180-182 of 186)

Chemical answers whether the proposed project affords *some* protection to the environment, but that is not the question. Because the EAS fails to make the requisite evaluation of whether other projects might afford *more* environmental protection, it must be rejected.

Yuhuang Chemical makes no effort to examine the possibility of meeting the project goal by restarting old facilities or increasing the production capacity of existing methanol facilities. Commercial grade methanol can be produced and sold to domestic and international consumers from restarted plants that were formerly dormant. In the late 1990's and early 2000's, high natural gas prices forced the closure of some methanol production facilities. At present, however, low-cost shale gas in North America, combined with demand growth in China has led to the reopening of dormant facilities. In Medicine Hat, Alberta, a facility owned by Methanex, inactive since 2001, resumed operation in 2011. On the Gulf Coast, a plant owned by LyondellBasell "was shut in 2004 because natural gas prices in the United States became too high." That plant reopened in 2014 with the capacity to produce 780,000 tons of methanol per year. The environmental impacts of restarting a dormant plant are likely less than building an entirely new facility on a sugar cane field next to an established community. Yuhuang Chemical's claim that it "is aware of no alternative projects that could achieve the project goals with a lesser environmental impact" fails to address the possibility of meeting project goals by restarting existing facilities.

Similarly, Yuhuang Chemical makes no effort to examine the possibility of meeting the project goals by expanding existing facilities. The Methanex facility in Medicine Hat, Alberta, is in the process of an expansion that would increase production by an additional 1.3 million tons/year, roughly 3,500 tons/day. In Texas, OCI Beaumont is expanding its Nederland facility to produce an additional 3,000 tons/day at an existing site. Together, the increased output from these expansions exceeds the 5,000 tons/day that Yuhuang Chemical proposes to produce. Again, Yuhuang Chemical ignores the possibility of meeting the project goal, to supply domestic and international markets, by expanding existing facilities.

Further, Yuhuang Chemical's evaluation of alternative sites cannot be used to satisfy LDEQ's public trustee duty. The EAS states "[Yuhuang Chemical] focused the site selection process along the Texas and Louisiana Gulf Coast. Within this area, Yuhuang Chemical identified the St. James Parish site as the most favorable available property that best met all of the siting criteria." But Yuhuang Chemical's listed criteria amount only to narrative support for the selected site without any specifics that would allow the necessary comparison of alternatives. Critical to any alternative site analysis, for example, is size, but Yuhuang failed to specify required site size. Yuhuang Chemical's analysis only states why it prefers this site, [*sic*] Yuhuang Chemical does not make the requisite analysis of whether other sites might be environmentally preferable without unduly curtailing the non-environmental benefits.

Yuhuang Chemical enumerates the following siting criteria in support of the proposed St. James location: cost and availability of natural gas; access to river and rail transportation and other existing infrastructure; sufficient acreage; availability of workforce; avoidance of environmental impacts; economic conditions and business climate. All of these benefits apply to a similarly sized and situated property currently for sale in Edgard, St. John the Baptist Parish. However, Yuhuang failed to provide any information regarding that site. Indeed, it failed to provide any information about any of the sites it purportedly considered. Yuhuang Chemical's EAS is flawed due to its myopic focus on only one site. LDEQ

cannot grant the permit based on this insufficient alternative site analysis. *See Matter of Browning-Ferris Indus. Petit Bois Landfill*, 657 So. 2d 633, 639 (La. App. 1 Cir. 6/23/95) ("After a careful review of the record in this matter, we are not convinced that BFI's 1990 alternative sites study submitted in connection with this matter was sufficient to enable DEQ (formerly ECC) to fulfill its responsibility for insuring 'that the environment would be protected to the maximum extent possible consistent with the health safety and welfare of the people.'").

In *Matter of American Waste and Pollution Control Co.*, a permit based on an IT Analysis that evaluated only one site "was issued erroneously without proper evaluation of alternative sites to determine comparative environmental impact." 633 So.2d 188, 196-7 (La. App. 1 Cir. 11/24/1993). Here, YCI only offers reasons as to why this is their favored site without any evaluation of alternative sites. LDEQ cannot make a proper evaluation of comparative impacts with nothing to compare the impacts to.

LDEQ Response to Comment No. 15

The matter of alternative sites is addressed in Section IV of LDEQ's Basis for Decision. The Basis for Decision:

- outlines Yuhuang's fundamental site selection criteria;
- summarizes the site-specific considerations resulting in the selection of the St. James property;
- identifies other sites in Louisiana considered by Yuhuang; and
- discusses why these sites were eliminated based on environmental and operational concerns.

LDEQ believes the site in Edgard, Louisiana, noted by the commenter to be the Goldmine Plantation. LDEQ understands that this property has been purchased by Eurochem.[33]

Finally, because Yuhuang considered more than one site, the Louisiana Court of Appeal decision referenced by the commenter is not relevant in the instant case.

The matter of alternative projects is addressed in Section V of LDEQ's Basis for Decision.

The commenter suggests that Yuhuang should have considered "restarting old facilities or increasing the production capacity of existing methanol facilities." However, the commenter provides no evidence that there are inactive methanol production facilities that are currently for sale and capable of achieving the goal of Yuhuang – that being to produce approximately 5000 metric tons per day of refined Grade AA methanol at a site with easy access to ocean-going vessels, barges, and railcars for the transportation of product to both North American and international customers. Further, Yuhuang has no existing operations located in the United States, so increasing the capacity of an existing methanol production facility is not possible.

In any event, LDEQ is not persuaded that the "environmental impacts of restarting a dormant plant" are necessarily less than those associated with the YCI Methanol Plant, as proposed. While restarting an existing facility may not, for example, impact wetlands, use of older technology would ostensibly require more natural gas (for both feedstock and fuel purposes) per unit of methanol produced and consequently result in higher emissions of criteria pollutants and greenhouse gases (relative to Air Liquide Lurgi MegaMethanol® technology).

[33] http://theadvocate.com/news/neworleans/12220391-148/eurochem-chooses-st-john-the

Comment No. 16

Yuhuang Chemical's EAS fails to Demonstrate that the Proposed Project Avoids Environmental Effects to the Maximum Extent Possible and Fails to Adequately Evaluate Potential Mitigation Measures.

Yuhuang Chemical failed to employ a design that "avoid[s] to the maximum extent possible" "the potential and real adverse environmental effects" of the pollutants the proposed plant will emit. Yuhuang Chemical also fails to adequately evaluate mitigation measures which would offer more environmental protection without unduly curtailing non-environmental benefits. The comments prepared by Phyllis Fox, Ph.D., PE, attached as Exhibit A, address these issues.

LDEQ Response to Comment No. 16

See LDEQ Response to Comment Nos. 18 – 40.

Comment No. 17

LDEQ Must Consider the Disparate Impact of the Emissions on the Predominantly African-American Community of St. James in Accordance with Environmental Justice Review Standards.

The St. James community is already inundated with air pollution. LDEQ must consider the disparate impact of the emissions on this predominantly African-American community in accordance with Environmental Justice review standards before it can issue this permit. See 2010 Census Date for St. James, La., Ex. P. LDEQ must consider the combined effect of the emissions from the existing facilities that are in the St. James community, including, but not limited to:

- ST. JAMES REFINERY located 9673 Highway 18,
- AMERICAS STYRENICS LLC located 9901 Highway 18
- MOASIC [*sic*] fertilizer plant, located at 9959 Hwy 18
- PLAINS MARKETING, LP / ST. JAMES TERMINAL 6410 Plains Terminal Road
- NUSTAR LOGISTICS, LP / ST. JAMES TERMINAL located 7167 Koch Road
- SHELL PIPELINE COMPANY, LP / ST. JAMES CAPLINE TERMINAL located 6770 Highway 18

LDEQ must also consider the combined effect of the emissions from the existing facilities that are just across the Mississippi River in Convent, including, but not limited to:

- AIR PRODUCTS & CHEMICALS, INC. (APCI) / CONVENT HYDROGEN PLANT located 10759 Convent Way (LA Hwy 70 at Hwy 44; Plant is located at the Motiva Refinery Site)
- NUCOR STEEL LOUISIANA – Pig Iron and DRI Plants, located 8325 LA Highway 3125
- OCCIDENTAL CHEMICAL CORPORATION (OXYCHEM) / OXYCHEM - CONVENT FACILITY located 7377 Highway 3214
- MOTIVA CONVENT REFINERY located at Hwy 70 and Hwy 44
- MOTIVA ENTERPRISES LLC - CONVENT MARKETING TERMINAL located at the same address

- TRANSCONTINENTAL GAS PIPELINE COMPANY, LLC-COMPRESSOR STATION - 8797 Helvetia Street

LDEQ is responsible for issuing air permits for all of these plants and it has all of the information regarding the emissions it has permitted for these plants, along information [*sic*] detailing the actual emissions the plants report to LDEQ. LDEQ must determine whether the effect of all of these emissions creates a disparate burden on the St. James community.

* * *

And as we're going through, the thing that the Department of Environmental Quality also needs to do, in this analysis of permits, is to take into account the other facilities in the regional area where this plant is located in St. James Parish.

We all know that there are a number of plants close to where this facility is going; those plants have a significant impact on the communities; this would be an additive impact; and the Department of Environmental Quality needs to do a complete Environmental Justice Review before this permit can be issued.[34]

LDEQ Response to Comment No. 17

The matter of environmental justice is addressed in Section IX of LDEQ's Basis for Decision. In sum, where an air quality concern is raised regarding a pollutant regulated pursuant to an ambient, health-based standard (such as a NAAQS), and where the area in question is in compliance with, and will continue after the operation of the challenged facility to comply with, that standard,[35] the air quality in the surrounding community is presumptively protective and emissions of that pollutant should not be viewed as "adverse" within the meaning of Title VI of the Civil Rights Act.

In addition, LDEQ evaluated whether the net effect of individual permitting decisions has, over time, increased the burden on the St. James community. LDEQ compared 1995 Toxics Release Inventory (TRI) data and 1996 criteria pollutant and toxic air pollutant (TAP) emissions inventories to corresponding 2013 data.[36] The results show dramatic declines in all three metrics.

Metric	Percent Change
TRI [37]	-68.8 %
Criteria [38]	-47.8 %
TAPs	-57.4 %

[34] Oral comments of Mr. Darryl Malek-Wiley (EDMS Doc ID 9694708, p. 49 of 87)

[35] See LDEQ Response to Comment No. 8.

[36] This baseline was selected because EPA analyzed 1995 TRI and 1996 TEDI (i.e., TAP) data in assessing a historical Title VI complaint involving a proposed facility in St. James Parish. See "Title VI Administrative Complaint re: Louisiana Department of Environmental Quality/Permit for Proposed Shintech Facility, Draft Revised Demographic Information," U.S. EPA, Office of Civil Rights, April 1998 (www.epa.gov/civilrights/docs/shintech/apr98/cover48.pdf).

[37] Total On-Site Disposal or Other Releases (http://iaspub.epa.gov/triexplorer/tri_release.chemical)

[38] Criteria and TAP emissions per LDEQ's Emissions Reporting and Inventory Center (ERIC) (http://business.deq.louisiana.gov/Eric/EricReports). TSP was counted as PM_{10} for the 1996 baseline.

Comment No. 18

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, based on reliable test data including recent tests of large-scale, commercial flares. The new flare NOx emission factor is 2.9 lb/MMBtu, supported by recent test data. 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.

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.

* * *

[T]he noxious [NO_X] emissions, from the flares alone, at this proposed facility are more than enough to classify the facility as a major source, just on non-routine flourine [flaring] emissions, that they would exceed over a hundred times [tons] per year.[39]

LDEQ Response to Comment No. 18

EPA finalized revisions to Section 13.5 (Industrial Flares) of AP-42 in April 2015.[40] EPA did *not* revise the emission factor for NO_X to 2.9 lb/MM Btu (as the commenter suggested would happen), but left it unchanged at 0.068 lb/MM Btu. Therefore, the basis for the NO_X limitations in the permit remains reasonable.

LDEQ did, however, revise the permit limitations for CO and VOC to reflect use of the new emission factors of 0.31 lb/MM Btu and 0.57 lb/MM Btu, respectively.

Comment No. 19

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

[39] Oral comments of Mr. Darryl Malek-Wiley (EDMS Doc ID 9694708, p. 50 of 87)
[40] http://www.epa.gov/ttn/chief/ap42/ch13/index.html

emission 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 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.

LDEQ Response to Comment No. 19

The commenter is correct in that Yuhuang's December 12, 2014, submittal noted that a "safety factor was added to the annual emissions for the flare to account for the final design case."[41] However, Yuhuang has since reevaluated potential emissions from the flare and determined that a safety factor is not necessary.[42] Accordingly, a safety factor will not be applied to calculated emissions of $PM_{10}/PM_{2.5}$, NO_X, or CO.

Comment No. 20

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 Response to Comment No. 20

The maximum pound per hour rate for NO_X is associated with startup of the YCI Methanol Plant, not with an upset condition.

The permit does not authorize emissions associated with upsets. Per LAC 33:III.501.B.1.e, the requirement to obtain a permit does not apply to upsets as defined in LAC 33:III507.J.1.

However, the permit requires continuous monitoring of the volume of vent gas routed to the flare. In addition, unauthorized discharges (i.e., upsets and malfunctions) must be reported in accordance with LAC 33:I.Chapter 39 (Notification Regulations and Procedures for Unauthorized Discharges) and LAC 33:III.919 (Emissions Inventory).

[41] EDMS Doc ID 9570680 (p. 2 of 43)
[42] EDMS Doc ID 9737811

Comment No. 21

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% O2. 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/106 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. 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.

LDEQ Response to Comment No. 21

Annual CO emissions from the auxiliary boiler are indeed based on an average CO concentration of 30 parts per million. This figure was derived from data provided by the technology provider, Air Liquide. Data supplied by vendors is generally more accurate than and is preferred by LDEQ over AP-42 factors.[43]

If CO emissions from the auxiliary boiler are determined to be higher than allowed by the permit, Yuhuang would be in violation of the permit and subject to enforcement action.[44] If CO emissions from the auxiliary boiler are such that potential CO emissions from the YCI Methanol Plant exceed 100 tons per year, the facility would be a major stationary source under the Prevention of Significant Deterioration (PSD) program (LAC 33:III.509), and sources of CO emissions would have to be controlled via best available control technology (BACT). In such a circumstance, LDEQ could require Yuhuang to install an oxidation catalyst, which would convert CO to carbon dioxide (CO_2). The design of the SCR can accommodate an oxidation catalyst.

Regarding monitoring, in addition to the initial and periodic stack tests described by the commenter, the auxiliary boiler will be equipped with a continuous oxygen trim system. An oxygen trim system is "a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller."[45] The oxygen trim system functions to continuously measure and maintain the optimum air to fuel ratio. Therefore, a CO CEMS is not required.

Comment No. 22

> 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/106 scf. AP-42, Table 1.4-1. This corresponds to about 100 ppm dry basis at 3% O2, which is about a factor of ten higher than assumed in the Application's CO emission calculations for the SMR.

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[43] *Louisiana Guidance for Air Permitting Actions*, rev. 5 (p. 24) (http://www.deq.louisiana.gov/portal/DIVISIONS/AirPermitsEngineeringandPlanning.aspx)

[44] See, for example, Part 70 General Condition C of LAC 33:III.535, Louisiana General Conditions II and III of LAC 33:III.537, 40 CFR 70.6(b)(1), and LAC 33:III.501.C.4.

[45] 40 CFR 63.7575

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. 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 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. 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 Response to Comment No. 22

As noted in LDEQ Response to Comment No. 21, data supplied by vendors is generally more accurate than and is preferred by LDEQ over AP-42 factors. As before, if CO emissions from the SMR are determined to be higher than allowed by the permit, Yuhuang would be in violation of the permit and subject to enforcement action. If CO emissions from the SMR are such that potential CO emissions from the YCI Methanol Plant exceed 100 tons per year, the facility would be a major stationary source under the PSD program, and sources of CO emissions would have to be controlled via BACT. In such a circumstance, LDEQ could require Yuhuang to install an oxidation catalyst. The SMR will also be equipped with a continuous oxygen trim system.

Comment No. 23

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; from the auxiliary boiler, 166 ton/yr; and from the flare, 231 ton/yr. 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.

LDEQ Response to Comment No. 23

Contrary to the assertion of the commenter, the permit limitations include startup and shutdown emissions and "all operation at the maximum emission rate." They only exclude emissions associated with malfunctions, which LDEQ considers to be excess emissions.

There are no viable operating scenarios in which the SMR, auxiliary boiler, or flare could operate at their maximum emission rates continuously. For example, the maximum pound per hour rates for the SMR and auxiliary boiler are associated with startup, shutdown, and maintenance events and other transient operating conditions. The maximum pound per hour rates for the flare are associated with startup of the YCI Methanol Plant; elevated emissions are also associated with methanol catalyst reduction.[46] Again, these operating conditions cannot be sustained for extended periods.

Notwithstanding these practical considerations, the ton per year limits of the permit also serve to restrict potential to emit. According to EPA, "if a permit applicant agrees to an enforceable limit that is sufficient to restrict PTE, the facility's PTE is calculated based on that limit."[47] The limits in Permit No. 2560-00295-V0 are both federally enforceable and enforceable as a practical matter (or practically enforceable).

Comment No. 24

The Flare Safety Factor were [sic] 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.

[46] For pollutants other than VOC and methanol.
[47] *In the Matter of Cash Creek Generation, LLC*, Order on Petition No. IV-2010-4 at 15 (June 22, 2012)

The VOC emission calculations include a safety factor of 44, which was applied to the average hourly flare VOC emission rate. 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, which was used to calculate the potential to emit CO from the flare of 2.34 ton/yr. 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. 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.

LDEQ Response to Comment No. 24

See LDEQ Response to Comment No. 19.

Comment No. 25

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.

LDEQ Response to Comment No. 25

See LDEQ Response to Comment No. 20.

Comment No. 26

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. 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 Response to Comment No. 26

At the request of LDEQ, Yuhuang reexamined potential fugitive emissions of CO. By additional information dated April 21, 2015, Yuhuang reported such emissions to be only 0.14 tons per year based on the maximum weight percent of CO in the fuel gas system.[48] Permit limitations were revised accordingly.

Comment No. 27

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." 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

[48] EDMS Doc ID 9737811

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 Response to Comment No. 27

The permit does not allow Yuhuang to "simply assert an emission level without any obligation to demonstrate the Facility is actually meeting it." Proposed Specific Requirement 214 limits aggregate VOC and methanol emissions from the sources in the cap and requires such emissions to be calculated monthly. Proposed Specific Requirement 258 requires Yuhuang to "monitor and record the throughput of each tank during each calendar month." In addition, LDEQ added a condition to the permit requiring emissions from the crude methanol and methanol product tanks to be calculated using either Tanks 4.09 (or subsequent revision) or Section 7.1 (Organic Liquid Storage Tanks) of AP-42.

Regarding the need for "limits on vapor pressure and temperature for storage tanks and loading operations," see LDEQ Response to Comment Nos. 35 and 36.

Regarding "tanks that are improperly operated, defective (e.g. damaged floating roof rim seals and deck fitting), or in disrepair," see LDEQ Response to Comment No. 38.

Comment No. 28

The Loading Emissions Factor is Underestimated.

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.

LDEQ Response to Comment No. 28

Though the S factors described by the commenter are used to determine potential emissions, it is not necessary for the permit to prescribe a particular "mode of operation" for several reasons.

With respect to marine loading operations, the S factor employed to determine the maximum pound per hour limit for VOC was 0.5. This represents the most conservative (i.e., highest) S factor for marine vessels in Table 5.2-1 of AP-42 Section 5.2.

With respect to truck and railcar loading operations, proposed Specific Requirement 119 requires "an organic monitoring device equipped with a continuous recorder" per 40 CFR 63.127(b). Thus, compliance with permit limits can be verified without using AP-42 equations.

The commenter's comment about the required control efficiency is addressed in LDEQ Response to Comment Nos. 29 and 30, and that pertaining to the maximum emission rate is addressed in LDEQ Response to Comment No. 31.

Comment No. 29

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 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. This change alone is high enough to increase the Facility's potential to emit VOC from 80.49 ton/yr to 107 ton/yr. 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.

LDEQ Response to Comment No. 29

Contrary to the assertion of the commenter, the permit does not require "only" a 90% control efficiency for either truck and railcar or marine loading operations. The two 90% standards referenced above are set forth in LAC 33:III.2107.B (for truck and railcar loading operations) and LAC 33:III.2108.C.2 (for marine loading operations) and were included in the permit because they are "applicable requirements" as defined in 40 CFR 70.2.

However, in the present case, truck and railcar loading operations must meet the more stringent requirements of 40 CFR 63 Subpart G (National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater);[49] and marine loading operations must meet the more stringent requirements of 40 CFR 63 Subpart Y (National Emission Standards for Marine Tank Vessel Loading Operations).[50]

Regarding truck and railcar loading operations, proposed Specific Requirement 113 requires Yuhuang to:

> Reduce emissions of total organic hazardous air pollutants by 98 weight-percent or to an exit concentration of 20 parts per million by volume, whichever is less stringent. [40 CFR 63.126(b)]

Regarding marine loading operations, proposed Specific Requirement 137 (not 136) requires Yuhuang to:

> Reduce HAP emissions from marine tank vessel loading operations by 98 weight-percent, as determined using methods in 40 CFR 63.565(d) and (l). [40 CFR 63.562(b)(3)]

Further, the application clearly states that methanol is the only product to be loaded; therefore, any requirement that restricts HAP emissions equally restricts VOC emissions.

Comment No. 30

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. 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. The revised potential to emit, assuming the proposed permit limits, is 112 ton/yr for VOCs. 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.

[49] Proposed Specific Requirements 112 – 131
[50] Proposed Specific Requirements 136 – 158

LDEQ Response to Comment No. 30

The two standards referenced by the commenter – 0.25 pounds of total organic compounds (TOC) per 1000 gallons of VOCs loaded into barges and 0.1 pounds of TOC per 1000 gallons of VOCs loaded into ships – are prescribed by LAC 33:III.2108.C.3. These provisions were included in the permit because they are "applicable requirements" as defined in 40 CFR 70.2. However, as noted in LDEQ Response to Comment No. 29, marine loading operations must meet the more stringent requirements of 40 CFR 63 Subpart Y, and emissions must be controlled by 98%.

Note also that use of the 2.16 lb VOC/1000 gallons loaded emission factor conservatively assumes that methanol will be loaded only into trucks and railcars, not barges or ships. The corresponding emission factor for marine loading operations is 1.80 lb VOC/1000 gallons loaded.

Comment No. 31

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. 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, and 116.5 ton/yr, assuming 90% control. 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, assuming 98% VOC control and 196.8 ton/yr, assuming 90% VOC control. Thus, the Facility is major for VOCs.

LDEQ Response to Comment No. 31

Annual emissions are limited by the volume of methanol loaded into trucks, railcars, and marine vessels. Because the permit limits throughput to 308,639,340 gallons per year, potential VOC emissions can be no more than 6.66 tons per year. The maximum pound per hour rate accounts for the "maximum pump rate during loading operations."[51]

Regarding the proper control efficiency (i.e., 98%), see LDEQ Response to Comment Nos. 29 and 30.

[51] EDMS Doc ID 9527280 (p. 162 of 186)

Comment No. 32

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.

LDEQ Response to Comment No. 32

Regarding truck and railcar loading operations, LAC 33:III.2107.B states, in relevant part:

> Provisions must be made to prevent spills during the attachment and disconnection of filling lines or arms. Loading and vapor lines must be equipped with fittings which close automatically when disconnected, or must be equipped to permit residual VOC in the loading line to discharge into a collection system or disposal or recycling system.[52]

Similarly, LAC 33:III.2108.G.2, which pertains to marine loading operations, specifies that:

> Provisions must be made to prevent spills or leaks during attachment or disconnection of filling lines, hoses or arms. Liquids subject to this rule shall not be spilled or handled in any other manner that would result in evaporation to the atmosphere.[53]

Accordingly, any emissions attributed to spills should be negligible.

Comment No. 33

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

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.

[52] Proposed Specific Requirement 132
[53] Proposed Specific Requirement 162

In comparison, for marine loading, the proposed permit contains detailed monitoring and recordkeeping requirements (EQT 0016, Conditions 133-162),[54] 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.

LDEQ Response to Comment No. 33

As noted in LDEQ Response to Comment No. 29, the permit requires emissions from truck and railcar loading operations to be controlled by 98%. In addition, the permit is not silent as to how compliance must be demonstrated. Proposed Specific Requirement 119 requires "an organic monitoring device equipped with a continuous recorder" per 40 CFR 63.127(b). Detailed monitoring, recordkeeping, and reporting requirements (as well as control technology requirements) are prescribed by 40 CFR 63 Subpart G and set forth in Specific Requirements 112 – 131.

Comment No. 34

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. The maximum VOC emissions, absent an enforceable limit to the contrary, from the auxiliary boiler, would be 20.7 ton/yr.

[54] Presumably, the commenter intended to refer to Specific Requirements 136 (not 133) to 162. Specific Requirements 133-135 apply to truck and railcar loading operations.

LDEQ Response to Comment No. 34

See LDEQ Response to Comment No. 23. LDEQ disagrees that the VOC permit limits for the SMR and auxiliary boiler are "unenforceable" simply because the proposed permit does not require a performance test. Nevertheless, because the SMR will control organic compounds from distillation operations and reactor processes, LDEQ added a condition to the permit requiring Yuhuang to conduct initial and periodic stack tests for VOC.

Comment No. 35

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.

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.

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.

LDEQ Response to Comment No. 35

The reference to 149°F in the Tanks 4.0 report for the crude methanol tank in Yuhuang's December 12, 2014, submittal was in error.[55] This discrepancy was corrected via additional information dated April 23, 2015.

135°F (equating to a vapor pressure of 10.9 psia) represents the highest possible temperature at which methanol can be delivered to the crude methanol tank. However, notwithstanding the "heated to" language in the permit application, the tank will not be heated, so the actual storage temperature of the liquid will decline over time. Because emissions calculations are conservatively based on a constant "worst-case" temperature, monitoring of the storage temperature or vapor pressure is not warranted.

Regarding enforceability of the Methanol Transfer and Storage Cap, see LDEQ Response to Comment No. 27.

Finally, because the maximum true vapor pressure of the crude methanol will be less than 11 psia, the provisions of 40 CFR 63.119(a)(2) and LAC 33:III.2103.F do not apply.

Comment No. 36

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.

[55] 149°F is the boiling point of methanol.

LDEQ Response to Comment No. 36

104°F represents the highest possible temperature at which methanol can be delivered to the methanol product tanks. However, notwithstanding the "heated to" language in the permit application, the tanks will not be heated, so the actual storage temperature of the liquid will decline over time. Because emissions calculations are conservatively based on a constant "worst-case" temperature, monitoring of the storage temperature or vapor pressure is not warranted.

This logic also holds for loading operations, as such emissions are based on a temperature of 104°F and a vapor pressure of 5.08 psia.[56]

Regarding upsets, see LDEQ Response to Comment No. 20.

Comment No. 37

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. 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. 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.

These losses are called "roof landing losses."

[56] LDEQ Response to Comment No. 28 is also relevant to the monitoring of loading operations.

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.

The EPA recommends methods to estimate emissions from degassing, cleaning, and roof landing losses. 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. They are required to be reported, for example, in Texas. They are also included in the emission inventories of crude oil terminals, 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.

LDEQ Response to Comment No. 37

At the request of LDEQ, Yuhuang quantified emissions associated with roof landings and tank cleanings, and the Methanol Transfer and Storage Cap was revised accordingly.[57] LDEQ added a condition to the permit requiring Yuhuang to record the number and duration of roof landings and the number of tank cleanings.

Note that proposed Specific Requirement 235 specifies that:

> The internal floating roof shall be floating on the liquid surface at all times except when the floating roof must be supported by the leg supports during the initial fill, after the vessel has been completely emptied and degassed, and when the vessel is completely emptied before being subsequently refilled. When the floating roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as soon as practical. The intent of these requirements is to avoid having a vapor space between the floating roof and the stored liquid for extended periods. Storage vessels may be emptied for purposes such as routine storage vessel maintenance, inspections, petroleum liquid deliveries, or transfer operations. Storage vessels where liquid is left on walls, as bottom clingage, or in pools due to floor irregularity are considered completely empty. [40 CFR 63.119(b)(1)-(2)]

[57] EDMS Doc ID 9737811

Comment No. 38

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. These non-routine emissions must be included in the potential to emit.

LDEQ Response to Comment No. 38

Authorizing emissions associated with storage vessels that are "improperly operated, defective (e.g., damaged floating roof rim seals and deck fitting), or in disrepair" is neither prudent nor protective of the environment. Yuhuang has a general duty to operate and maintain the YCI Methanol Plant, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions at all times, including periods of startup, shutdown, and malfunction.[58]

Even if emissions associated with malfunctions were addressed by the permit, malfunctions exclude "[f]ailures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown."[59]

Comment No. 39

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. 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. This Facility also selected internal floating roof tanks with

[58] 40 CFR 63.6(e)
[59] LAC 33:III.111.A

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 Response to Comment No. 39

LDEQ understands that Yuhuang will operate the crude methanol tank and methanol product tanks using nitrogen blankets.[60] LDEQ added a condition to the permit requiring Yuhuang to meet National Fire Protection Association (NFPA) 69 (Standard on Explosion Prevention Systems) guidelines.

Comment No. 40

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. 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.

LDEQ Response to Comment No. 40

LDEQ is aware that Air Liquide will construct an air separation unit (ASU) to supply oxygen to the YCI Methanol Plant. According to Air Liquide's press release, the ASU will be "[c]onnected to Air Liquide's extensive pipeline system in Louisiana" and produce nitrogen and argon in addition to oxygen.[61] LDEQ understands that the ASU will supply produced gases to customers other than Yuhuang. Because the two facilities will not be "under common control of the same person (or persons under common control)," they will not constitute a single "major source."[62]

Moreover, LDEQ also understands that potential emissions from the ASU are such that it will not require an air permit per LAC 33:III.501.B.2.d. Thus, even if emissions from the ASU and YCI Methanol Plant were aggregated, the YCI Methanol Plant would not be a major source of criteria pollutants.

Comment No. 41

By looking at the detailed permit, we feel that we need to do a Prevention of Significant Deterioration, or PSD permit, rather than the proposed process you're going through here; we feel that, in analyzing the data that the Company provided, that, in a number of cases for covering monoxide, nitrogen oxide, and BOC [VOC], each of these, by the Company's own numbers, are over the 100 tons per year threshold; therefore, we should be doing a PSD permit, rather than this (Title V) permit.[63]

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[60] Verbal communication with Environ.

[61] http://www.airliquide.com/en/rss/major-investment-in-the-us-air-liquide-to-supply-oxygen-to-new-large-scale-methanol-production-complex-in-louisiana.html

[62] LAC 33:III.502.A.*Major Source*

[63] Oral comments of Mr. Darryl Malek-Wiley (EDMS Doc ID 9694708, pp. 48-49 of 87)

* * *

> In the analysis that the Company has done, they used older techniques; older analyses that the EPA has changed to a modern scientific analysis effort that would increase the numbers the Company used; we feel that, in a couple of cases, the Company has been very, very conservative on its numbers; and that the more realistic analysis of emissions would show that this would be -- specifically, the Company would have to do a PSD permit.[64]

LDEQ Response to Comment No. 41

Because permitted emissions of each "regulated NSR pollutant" (i.e., PM_{10}, $PM_{2.5}$, SO_2, NO_X, CO, and VOC) are less than 100 tons per year, the YCI Methanol Plant is not a major stationary source under the PSD program, LAC 33:III.509.

Regarding the calculation of potential emissions, see LDEQ Response to Comment Nos. 18 – 38.

[64] *Id.* (pp. 50-51 of 87)

ENVIRON

LDEQ RECEIPT

2015 APR 22 AM 7:37

April 21, 2015

HAND DELIVERED

Ms. Tegan Treadaway
Assistant Secretary
Louisiana Department of Environmental Quality
Office of Environmental Services
P.O. Box 4313
Baton Rouge, LA 70821-4313

RE: Yuhuang Chemical Inc.
Methanol Plant
St. James Parish, Louisiana
Initial Title V Permit Application
Tempo Activity No.: PER20140001
AI #: 194165

Dear Ms. Treadaway:

On behalf of Yuhuang Chemical Inc. (YCI), ENVIRON International Corporation (ENVIRON) is submitting the enclosed revisions to the emission rates for the Flare (EPN FLR), Fugitives (EPN FUG), and Methanol Transfer and Storage Cap (EPN MTSCAP) to be incorporated into the permit before issuance. Enclosed please find the updated emission calculations and associated EIQ sheets.

We look forward to working with you and your staff during your review of this application, and we will be glad to answer any questions or to provide additional information if required for the review. Please feel free to contact me at (225) 408-2741 or via email at bglover@environcorp.com.

Sincerely,

Brian Glover
Principal

Enclosures

ENVIRON International Corp. 8235 YMCA Plaza Drive, Suite 300, Baton Rouge, LA 70810
V +1 225.408.2696 F +1 225.408.2747

environcorp.com

Attachment A

Revised Emission Calculations

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant
Summary of Emissions

Source Description	Pollutant (tpy)									
	PM	PM_{10}	$PM_{2.5}$	SO_2	NO_x	CO	VOC	CO_2e	Ammonia	Methanol
SMR	39.16	39.16	39.16	3.15	52.56	34.78	28.34	1,338,160	21.12	4.61
Auxiliary Boiler	17.30	17.30	17.30	1.40	23.08	49.67	12.48	270,217	10.05	---
Flare	0.05	0.05	0.05	0.21	7.25	1.98	1.35	12,410	---	0.15
Emergency Generator	0.07	0.07	0.07	2.16E-03	2.16	1.17	0.13	234	---	---
Firewater Pump No. 1	0.01	0.01	0.01	3.18E-04	0.20	0.17	0.07	34	---	---
Firewater Pump No. 2	0.01	0.01	0.01	3.18E-04	0.20	0.17	0.07	34	---	---
Cooling Tower	3.26	2.77	1.32	---	---	---	8.65	---	---	8.65
Fugitives	---	---	---	---	---	---	4.50	---	0.03	4.31
Ammonia Tank	---	---	---	---	---	---	---	---	0.43	---
Transfer and Storage Cap	---	---	---	---	---	---	19.80	---	---	19.80
Wastewater	---	---	---	---	---	---	3.00	---	0.09	3.00
Total (tpy)	**59.86**	**59.37**	**57.92**	**4.76**	**85.45**	**87.94**	**78.39**	**1,621,089**	**31.72**	**40.52**

Ex. D

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Flare Summary

Signature: KNG
Checked: AMH

Source: Flare Summary
Source ID: FLR

Date: 4/21/2015

Description:

Below is a summary of emissions for the flare associated with the flare pilot, vents from startup/shutdown activities, and purge streams. Detailed emission calculations for each of these categories are calculated separately.

Emissions Summary:

Pollutant	Pilot (tpy)	SUSD (tpy)	Purge (tpy)	Average Emissions (lb/hr)	Maximum Emissions (lb/hr)	Annual Emissions (tpy)
CO	0.13	1.82	0.02	0.45	44.25	1.98
N	0.13	7.11	0.01	1.66	184.46	7.25
$PM/PM_{10}/PM_{2.5}$	0.01	0.04	0.00001	0.01	1.10	0.05
SO_2	0.001	0.20	0.0001	0.05	5.30	0.21
VOC	0.01	1.19	0.15	0.31	1.76	1.35
Methanol	--	--	0.15	0.03	1.76	0.15

O_x

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Flare Pilot Emission Calculations

Signature: KNG
Checked: BMH
Source: Flare Pilot
Source ID: FLR
Date: 10/27/2014

Description:
Pilot emissions from the combustion of Natural Gas to the flare are estimated below.

Basis	Unit	Parameter	Source
1,020	btu/scf	Heating Value	EPA AP-42 Section 1.4: Natural Gas Combustion
0.31	MMbtu/hr	Heat Input	Air Liquide vendor data.
304	scfh	Fuel Flow	Calculated from Heating Value and Heat Input.
8,760	hours/yr	Operating Time	Air Liquide vendor data.
2,716	MMBtu/yr	Annual Average Heat Input	Calculated from Heat Input (MMBtu/hr) and the Annual Operating Hours (hr/yr).

Emissions Summary:

Component	Emission factor		Emissions (lb/hr)	Emissions (tpy)	Emission Factor Source
NO_x	100	lb/MMscf	0.03	0.13	AP-42 Table 1.4-1
CO	84	lb/MMscf	0.03	0.13	AP-42 Table 1.4-1
$PM/PM_{10}/PM_{2.5}$ [2]	7.6	lb/MMscf	0.002	0.01	AP-42 Table 1.4-2. All PM (total, condensable, and filterable) is assumed to be less than 1.0 micrometer in diameter. Since the flare will fire gaseous fuels only, it is assumed that $PM_{2.5}$ is equal to PM_{10}.
SO_2	0.6	lb/MMscf	0.0002	0.001	AP-42 Table 1.4-2
VOC	5.5	lb/MMscf	0.002	0.01	AP-42 Table 1.4-2

Summary of GHG Emissions:
Fuel Combustion (40 CFR 98 Subpart C)

Pollutant	Emission Factor (kg/MMBtu)[1]	Emissions (metric tons/yr)[2]	Emissions (US tons/yr)[3]
CO_2	53.06	144.09	158.79
CH_4	1.0E-03	0.0027	0.0030
N_2O	1.0E-04	0.0003	0.0003
CO_2e[4]	--	144.24	**158.95**

Notes
1. Based on EPA default factors in Subpart C Tables C-1 and C-2 for natural gas, revised 11/29/2013.
2. Calculated based on the heat input, emission factors, and equations C-1b and C-8b of Subpart C. CO_2e based on Subpart A Table A-1 factors.
   CO_2, CH_4, or N_2O (metric tpy) = 1E-03 * Gas (MMBtu/yr) * Emission Factor (kg/MMBtu)
3. 1 metric ton = 1.102 US ton
4. CO_2e = CO_2, CH_4, or N_2O (tpy) * Global Warming Potential factor (GWP). GWPs revised 11/29/2013.

CO_2 GWP	1
CH_4 GWP	25
N_2O GWP	298

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Flare SUSD Emission Calculations

Signature: KNG
Checked: AMH
Source: Flare SUSD
Source ID: FLR
Date: 4/21/2015

Description:
The flare will control emissions during once through nitrogen heating, start-up of methanol unit, and methanol catalyst reduction.
Emissions from upsets are not included in this emissions estimate.

Case 1: Once through Nitrogen Heating
Description: Nitrogen and steam mixture is passed through the reformers in a once through circuit before being released to Flare. LHV of combined gas being flared must be maintained at a minimum of 200 Btu/scf at all times by NG fuel addition.

Case 1: Stream Data

Parameter	Units	Value	Source
Duration	hr/yr	48	24 hours per startup, 2 start-ups per year. Air Liquide vendor data.
Discharge Temperature	°F	104	Air Liquide vendor data.
Discharge Temperature	R	563.67	Converted from Discharge Temperature (°F).
Discharge Pressure	barg	5	Air Liquide vendor data.
Discharge Pressure	atm (gauge)	4.93	Converted from Discharge Pressure (barg).
Molweight	lb/lbmol	28	Air Liquide vendor data.
Flow rate	lb-m/hr	4,131	Air Liquide vendor data.
Flow rate	scf/hr	55,993	Calculated from Molweight (lb/lbmol), Flow rate (lb-m/hr), and the Ideal Gas Law.
Lower Heating Value (LHV)	Btu/scf	300	Based on 40 CFR 60.18
Firing Rate (LHV)	MMBtu/hr	16.80	Calculated from Flow rate (scf/hr) and LHV (Btu/scf).
VOC Destruction Efficiency	%	98	Air Liquide vendor data.

Case 1: Combustion Emissions

Pollutant	Emission Factor (lb/mmbtu)	Emission Factor (lb/mmscf)	Emissions (lb/hr)	Emissions (tpy)	Emission Factor Source
VOC	0.57	--	0.19	0.005	AP-42 Table 13.5-2
Carbon monoxide	0.31	--	5.21	0.12	AP-42 Table 13.5-2
Nitrogen oxides	0.068	--	1.14	0.03	AP-42 Table 13.5-1
SO_2	--	0.6	0.03	0.0008	AP-42 Table 1.4-2
$PM/PM_{10}/PM_{2.5}$	--	0.12	0.007	0.0002	AP-42 Table 13.5-1, Footnote C. Based on 5% of 40 µg/L because the flare is non-smoking.

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Flare SUSD Emission Calculations

Signature: KNG
Checked: AMH

Source: Flare SUSD
Source ID: FLR

Date: 4/21/2015

Case 2: Start up of Methanol Unit
Description: Load of SMR is at 50%, and reformed gas is routed to Flare.

Case 2: Stream Data

Parameter	Units	Value	Source
Duration	hr/yr	48	24 hours per startup, 2 start-ups per year. Air Liquide vendor data.
Discharge Temperature	°F	104	Air Liquide vendor data.
Discharge Temperature	R	563.67	Converted from Discharge Temperature (°F).
Discharge Pressure	barg	30.20	Air Liquide vendor data.
Discharge Pressure	atm (gauge)	29.81	Converted from Discharge Pressure (barg).
Molweight	lb/lbmol	11.21	Air Liquide vendor data.
Flow rate	lb-m/hr	260,979	Air Liquide vendor data.
Flow rate	scf/hr	8,838,686	Calculated from Molweight (lb/lbmol), Flow rate (lb-m/hr), and the Ideal Gas Law.
Lower Heating Value (LHV)	Btu/lb	9,142	Air Liquide vendor data.
Firing Rate (LHV)	MMBtu/hr	2,386	Calculated from Flow rate (lb-m/hr) and LHV (Btu/lb).
Firing Rate (HHV)	MMBtu/hr	2,713	Air Liquide vendor data. Calculated from provided stream data below.
VOC Destruction Efficiency	%	98	Air Liquide vendor data.

Component	Mole Fraction	Molar Flow (lbmol/hr)	Heat of Combustion (MMBtu/lbmol)	Component Contribution (MMBtu/hr)
Methane	0.02	373	0.38	142.75
Hydrogen	0.6899	16,069	0.12	1,980.06
CO	0.2066	4,812	0.12	589.78
CO_2	0.0836	1,947		
Nitrogen	0.0007	16		
H_20	0.0026	61		
Argon	0.0006	14		
Total	**1.000**	**23,291**	**0.629**	**2,712.59**

Case 2: Combustion Emissions

Pollutant	Emission Factor (lb/mmbtu)	Emission Factor (lb/mmscf)	Emissions (lb/hr)	Emissions (tpy)	Emission Factor Source
VOC	0.57	--	30.92	0.74	AP-42 Table 13.5-2
Carbon monoxide[1]	0.31	--	44.25	1.06	AP-42 Table 13.5-2
Nitrogen oxides	0.068	--	184.46	4.43	AP-42 Table 13.5-1
SO_2	--	0.6	5.30	0.13	AP-42 Table 1.4-2
$PM/PM_{10}/PM_{2.5}$	--	0.12	1.10	0.03	AP-42 Table 13.5-1, Footnote C. Based on 5% of 40 µg/L because the flare is non-smoking.

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Flare SUSD Emission Calculations

Signature: KNG
Checked: AMH
Source: Flare SUSD
Source ID: FLR
Date: 4/21/2015

Case 3: Methanol Catalyst Reduction
Description: Load of SMR is at 30%. Part of the reformed gas is sent to PSA, and the excess is flared.

Case 3: Stream Data

Parameter	Units	Value	Source
Duration	hr/yr	48	48 hours/catalyst change out, once in 3-4 years. Air Liquide vendor data.
Discharge Temperature	°F	104	Air Liquide vendor data.
Discharge Temperature	R	563.67	Converted from Discharge Temperature (°F).
Discharge Pressure	barg	30.2	Air Liquide vendor data.
Discharge Pressure	atm (gauge)	29.81	Converted from Discharge Pressure (barg).
Molweight	lb/lbmol	11.205	Air Liquide vendor data.
Flow rate	lb-m/hr	156,588	Air Liquide vendor data. Flow is rated to 30%.
Flow rate	scf/hr	5,303,212	Calculated from Molweight (lb/lbmol), Flow rate (lb-m/hr), and the Ideal Gas Law.
Lower Heating Value (LHV)	Btu/lb	9,142	Air Liquide vendor data.
Firing Rate (LHV)	MMBtu/hr	1,431	Calculated from Flow rate (lb-m/hr) and LHV (Btu/lb).
Firing Rate (HHV)	MMBtu/hr	1,628	Air Liquide vendor data. Calculated from provided stream data below.
Destruction Efficiency	%	98	Air Liquide vendor data.

Component	Mole Fraction	Molar Flow (lbmol/hr)	Heat of Combustion (MMBtu/lbmol)	Component Contribution (MMBtu/hr)
Methane	0.02	224	0.38	85.65
Hydrogen	0.6899	9,641	0.12	1,188.04
CO	0.2066	2,887	0.12	353.87
CO_2	0.0836	1,168		
Nitrogen	0.0007	10		
H_20	0.0026	36		
Argon	0.0006	8		
Total	**1.000**	**13,975**	**0.629**	**1,627.55**

Case 3; Combustion Emissions

Pollutant	Emission Factor (lb/mmbtu)	Emission Factor (lb/mmscf)	Emissions (lb/hr)	Emissions (tpy)	Emission Factor Source
VOC	0.57	--	18.55	0.45	AP-42 Table 13.5-2
Carbon monoxide[1]	0.31	--	26.55	0.64	AP-42 Table 13.5-2
Nitrogen oxides	0.068	--	110.67	2.66	AP-42 Table 13.5-1
SO_2	-	0.6	3.18	0.08	AP-42 Table 1.4-2
$PM/PM_{10}/PM_{2.5}$	--	0.12	0.66	0.02	AP-42 Table 13.5-1, Footnote C. Based on 5% of 40 µg/L because the flare is non-smoking.

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Flare SUSD Emission Calculations

Signature: KNG
Checked: AMH

Source: Flare SUSD
Source ID: FLR

Date: 4/21/2015

GHG Emission Calculation Basis:

4,357 Hourly Average Heat Input (MMBtu/hr)

209,133 Annual Average Heat Input (MMBtu/yr)

Source:

Design Capacity Firing Rate.

Calculated from Design Capacity Firing Rate (MMBtu/hr) and the Annual Operating Hours (hr/yr).

Summary of GHG Emissions:
Fuel Combustion (40 CFR 98 Subpart C)

Pollutant	Emission Factor (kg/MMBtu)[2]	Emissions (metric tons/yr)[3]	Emissions (US tons/yr)[4]
CO_2	53.06	11,096.60	12,228.45
CH_4	1.0E-03	0.21	0.23
N_2O	1.0E-04	0.02	0.02
CO_2e[5]	--	11,108.06	**12,241.08**

Notes

1. CO emissions are based on the firing rate from the methane in the stream only. All other pollutants' emissions are based on the total firing rate of the stream.
2. Based on EPA default factors in Subpart C Tables C-1 and C-2 for natural gas.
3. Calculated based on the heat input, emission factors, and equations C-1b and C-8b of Subpart C. CO_2e based on Subpart A Table A-1 factors.

   CO_2, CH_4, or N_2O (metric tpy) = 1E-03 * Gas (MMBtu/yr) * Emission Factor (kg/MMBtu)
4. 1 metric ton = 1.102 US ton
5. CO_2e = CO_2, CH_4, or N_2O (tpy) * Global Warming Potential factor (GWP)

CO_2 GWP	1
CH_4 GWP	25
N_2O GWP	298

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Purge to Flare Emission Calculations

Signature: KNG
Checked: AMH

Source: Purge to Flare
Source ID: FLR

Date: 4/21/2015

Description:
The flare will control an intermittent purge stream of methanol vapor, as well as excess process gas from equipment clearing.

Methanol Purge Stream

Stream Data

Parameter	Units	Value	Source
Duration	hr/yr	168	Based on an estimated flow of one week per year.
Discharge Temperature	°F	95	Air Liquide vendor data.
Discharge Temperature	R	554.67	Converted from Discharge Temperature (°F).
Molweight	lb/lbmol	32	Air Liquide vendor data.
Flow rate	lb-m/hr	88	Air Liquide vendor data.
Flow rate	scf/hr	1,046	Calculated from Molweight (lb/lbmol), Flow rate (lb-m/hr), and the Ideal Gas Law.
Lower Heating Value (LHV)	Btu/lb	8,596	Air Liquide vendor data.
Firing Rate (LHV)	MMBtu/hr	0.76	Calculated from Flow rate (lb-m/hr) and LHV (Btu/lb).
Firing Rate (HHV)	MMBtu/hr	0.90	Calculated from provided stream data below.
VOC Destruction Efficiency	%	98	Air Liquide vendor data.

Component	Mole Fraction	Molar Flow (lbmol/hr)	Heat of Combustion (MMBtu/lbmol)	Component Contribution (MMBtu/hr)
Methanol	1.00	2.76	0.33	0.90

Combustion Emissions

Pollutant	Emission Factor (lb/mmbtu)	Emission Factor (lb/mmscf)	Emissions (lb/hr)	Emissions (tpy)	Emission Factor Source
Carbon monoxide	0.31	--	0.28	0.02	AP-42 Table 13.5-2
Nitrogen oxides	0.068	--	0.06	0.01	AP-42 Table 13.5-1
SO_2	--	0.6	6.27E-04	5.27E-05	AP-42 Table 1.4-2
$PM/PM_{10}/PM_{2.5}$	--	0.12	1.31E-04	1.10E-05	AP-42 Table 13.5-1, Footnote C. Based on 5% of 40 µg/L because the flare is non-smoking.
VOC	--	--	1.76	0.15	--
Methanol	--	--	1.76	0.15	--

Sample Calculations

Average Hourly Emissions for CO:

$$\frac{0.31 \text{ lb}}{1{,}000{,}000 \text{ BTU}} \times \frac{0.9 \text{ BTU}}{\text{hr}} = 0.28 \text{ lb/hr}$$

Average Hourly Emissions for SO_2:

$$\frac{0.6 \text{ lb}}{1{,}000{,}000 \text{ scf}} \times \frac{1046 \text{ scf}}{\text{hr}} = 0.0006 \text{ lb/hr}$$

Annual Hourly Emissions for VOC (Methanol):

$$\frac{88 \text{ lb}}{\text{hr}} \times \frac{100 - 98 \%}{} = 1.76 \text{ lb/hr}$$

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Purge to Flare Emission Calculations

Signature: KNG
Checked: AMH

Source: Purge to Flare
Source ID: FLR

Date: 4/21/2015

GHG Emission Calculation Basis:

152 Annual Average Heat Input (MMBtu/yr)

Summary of GHG Emissions
Fuel Combustion (40 CFR 98 Subpart C)

Pollutant	Emission Factor (kg/MMBtu)[1]	Emissions (metric tons/yr)[2]	Emissions (US tons/yr)[3]
CO_2	59.00	8.97	9.88
CH_4	3.0E-03	0.00	5.03E-04
N_2O	6.0E-04	0.00	1.01E-04
CO_2e^4	--	9.01	**9.93**

Notes

1. Based on EPA default factors in Subpart C Tables C-1 and C-2 for fuel gas.
2. Calculated based on the heat input, emission factors, and equations C-1b and C-8b of Subpart C. CO_2e based on Subpart A Table A-1 factors.
   CO_2, CH_4, or N_2O (metric tpy) = 1E-03 * Gas (MMBtu/yr) * Emission Factor (kg/MMBtu)
3. 1 metric ton = 1.102 US ton
4. CO_2e = CO_2, CH_4, or N_2O (tpy) * Global Warming Potential factor (GWP)

CO_2 GWP	1
CH_4 GWP	25
N_2O GWP	298

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Fugitives Emission Calculations

Signature:	KNG	Source:	Fugitives	Date:	4/21/2015
Checked:	AMH	Source ID:	FUG		

Description:

VOC, CO, CO_2, and NH_3 may be emitted from process fugitive components including valves, pumps, connectors, pressure relief devices, and other ancillary equipment in the Methanol Plant that will be associated with streams in fuel gas, syngas, and methanol service.

Summary of Fugitive Components by Type and Stream

Component Type	Stream		
	Non-fuel Gas System (Methanol and VOC)	Non-fuel Gas System (Syngas Compressor)	Fuel Gas System
Compressor Seals - Double	0	0	0
Compressor Seals - Single	0	1	1
Flanges - G	604	0	728
Flanges - HL	9	0	0
Flanges - LL	2110	0	0
Pump Seal - HL	0	0	0
Pump Seal - LL Double	28	0	0
Open Ended Lines	0	0	0
Relief Valves - Atm	0	0	0
Relief Valves - Closed	0	0	0
Relief Valves - Flare	2	0	0
Sample Connection - G	0	0	0
Sample Connection - HL	0	0	0
Sample Connection - LL	0	0	0
Valves - G	242	0	291
Valves - HL	3	0	0
Valves - LL	844	0	0

Summary of Fugitive Component Emission Factors and Control Efficiencies

Component Type	Emission Factor (kg/hr/source)[1]	Control %	Control Emission Factor (kg/hr/source)	Control Emission Factor (lb/hr/source)
Compressor Seals - Double	0.08940	0%	0.08940	0.19709
Compressor Seals - Single	0.08940	0%	0.08940	0.19709
Flanges - G	0.00008	0%	0.00008	0.00018
Flanges - HL	0.00008	0%	0.00008	0.00018
Flanges - LL	0.00008	0%	0.00008	0.00018
Pump Seal - HL	0.00210	0%	0.00210	0.00463
Pump Seal - LL Double	0.00187	0%	0.00187	0.00412
Open Ended Lines	0.00150	0%	0.00150	0.00331
Relief Valves - Atm	0.04470	0%	0.04470	0.09855
Relief Valves - Closed	0.04470	0%	0.04470	0.09855
Relief Valves - Flare	0.04470	98%	0.00089	0.00197
Sample Connection - G	0.00008	0%	0.00008	0.00018
Sample Connection - HL	0.00008	0%	0.00008	0.00018
Sample Connection - LL	0.00008	0%	0.00008	0.00018
Valves - G	0.00013	0%	0.00013	0.00029
Valves - HL	0.00023	0%	0.00023	0.00051
Valves - LL	0.00017	0%	0.00017	0.00036

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Fugitives Emission Calculations

Signature: KNG
Checked: AMH

Source: Fugitives
Source ID: FUG

Date: 4/21/2015

Hourly Emission Calculations by Component Type and Stream (lb/hr)

Component Type	Stream		
	Non-fuel Gas System (Methanol and VOC)	Non-fuel Gas System (Syngas Compressor)	Fuel Gas System
Compressor Seals - Double	0.00	0.00	0.00
Compressor Seals - Single	0.00	0.23	0.23
Flanges - G	0.11	0.00	0.13
Flanges - HL	0.00	0.00	0.00
Flanges - LL	0.38	0.00	0.00
Pump Seal - HL	0.00	0.00	0.00
Pump Seal - LL Double	0.11	0.00	0.00
Open Ended Lines	0.00	0.00	0.00
Relief Valves - Atm	0.00	0.00	0.00
Relief Valves - Closed	0.00	0.00	0.00
Relief Valves - Flare	0.00	0.00	0.00
Sample Connection - G	0.00	0.00	0.00
Sample Connection - HL	0.00	0.00	0.00
Sample Connection - LL	0.00	0.00	0.00
Valves - G	0.07	0.00	0.08
Valves - HL	0.00	0.00	0.00
Valves - LL	0.31	0.00	0.00
TOTAL	**0.98**	**0.23**	**0.44**

Annual Emission Calculations by Component Type and Stream (tpy)

Component Type	Stream		
	Non-fuel Gas System (Methanol and VOC)	Non-fuel Gas System (Syngas Compressor)	Fuel Gas System
Compressor Seals - Double	0.00	0.00	0.00
Compressor Seals - Single	0.00	0.99	0.99
Flanges - G	0.47	0.00	0.57
Flanges - HL	0.01	0.00	0.00
Flanges - LL	1.65	0.00	0.00
Pump Seal - HL	0.00	0.00	0.00
Pump Seal - LL Double	0.50	0.00	0.00
Open Ended Lines	0.00	0.00	0.00
Relief Valves - Atm	0.00	0.00	0.00
Relief Valves - Closed	0.00	0.00	0.00
Relief Valves - Flare	0.02	0.00	0.00
Sample Connection - G	0.00	0.00	0.00
Sample Connection - HL	0.00	0.00	0.00
Sample Connection - LL	0.00	0.00	0.00
Valves - G	0.31	0.00	0.37
Valves - HL	0.01	0.00	0.00
Valves - LL	1.34	0.00	0.00
TOTAL	**4.31**	**0.99**	**1.93**

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Fugitives Emission Calculations

Signature:	KNG	Source:	Fugitives	Date:	4/21/2015
Checked:	AMH	Source ID:	FUG		

Non-fuel Gas System (Methanol and VOC) Worst-case Speciated Emissions

Pollutant	Weight Fraction	Emissions (lb/hr)	Emissions (tpy)
Ammonia	0.00743	0.01	0.03
Methanol (VOC)	1	0.98	4.31

Non-fuel Gas System (Syngas Compressor) Worst-case Speciated Emissions

Pollutant	Weight Fraction	Emissions (lb/hr)	Emissions (tpy)
CO_2	1	0.23	0.99
CO_2e	1	0.23	0.99

Fuel Gas System Worst-case Speciated Emissions[2]

Pollutant	Weight Fraction	Emissions (lb/hr)	Emissions (tpy)
VOC	0.1	0.04	0.19
Methane	0.9	0.40	1.74
CO	0.071	0.03	0.14
CO_2e		7.77	34.02

Emissions Summary

Pollutant	Emissions (lb/hr)	Emissions (tpy)
Ammonia	0.01	0.03
Methanol	0.98	4.31
Total VOC	1.03	4.50
Methane	0.40	1.74
CO_2	0.23	0.99
CO_2e	7.99	35.01
CO	0.03	0.14

Notes:

1. EPA 453/R-95-017 Table 2-5. SOCMI Screening Ranges Emission Factors (<10,000 ppm_v).
2. CO composition based on Air Liquide vendor data.

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Methanol Transfer and Storage Cap Emissions Summary

Signature:	AMH	Source:	Methanol Transfer and Storage Cap	Date:	4/21/2015
Checked:	KNG	Source ID:	MTSCAP		

Description:

The Methanol Transfer and Storage Cap (MTSCAP) is a summary of average hourly and annual emissions from methanol loading operations, five (5) methanol product tanks, one (1) crude methanol tank, tank landings, and tank cleaning. Please refer to the following worksheets for detailed emission estimates for each of these activities.

Summary of Pollutant Emissions:

Pollutant	Average Emissions (lb/hr)	Annual Emissions (tpy)
Total VOC	4.52	19.80
Methanol	4.52	19.80

Ex. D

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Product Tanks Emission Calculations

Signature: DMS
Checked: AMH

Source: Product Tanks
Source ID: TK-26-202(A-E)

Date: 10/27/2014

Description:
Methanol will be stored in Internal Floating Roof tanks. Emissions from all methanol storage tanks are included as part of the Methanol Transfer and Storage CAP (MTSCAP).

Parameter	Basis	Units	Source
Chemical Stored:	Methanol Product		Based on project meeting between YCI, ENVIRON, and Air Liquide on September 26, 2014.
Volume:	8,000,000	gal	Based on project meeting between YCI, ENVIRON, and Air Liquide on September 26, 2014.
Diameter:	150.0	ft	Based on project meeting between YCI, ENVIRON, and Air Liquide on September 26, 2014.
Annual Throughput:	308,639,340	gal/yr	Air Liquide, "69919-PR-00038 Air Permit Data Rev. 01.xlsx."
Storage Temperature:	104	°F	Air Liquide, "69919-PR-00038 Air Permit Data Rev. 01.xlsx."
Number of Tanks:	5		Based on project meeting between YCI, ENVIRON, and Air Liquide on September 26, 2014.
Hours of Operation:	8,760	hr/yr	24 hr/day and 365 day/yr

EX. D

TANKS Output per Tank

Pollutant	TANKS Emissions (lbs/yr)
Total VOC	2,417.26
Methanol	2,417.26

Emissions Summary

Pollutant	Average Emissions (lbs/hr)	Annual Emissions (tons/yr)
Total VOC	1.38	6.04
Methanol	1.38	6.04

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Crude Methanol Tank Emission Calculations

Signature: KNG
Checked: AMH
Source: Crude Methanol Tank
Source ID: TK-26-201
Date: 12/5/2014

Description:
Crude methanol will be stored in an Internal Floating Roof tank. Emissions from all methanol storage tanks are included as part of the Methanol Transfer and Storage CAP (MTSCAP).

Parameter	Basis	Units	Source
Chemical Stored:	Crude Methanol		Based on project meeting between YCI, ENVIRON, and Air Liquide on September 26, 2014.
Volume:	8,000,000	gal	Based on project meeting between YCI, ENVIRON, and Air Liquide on September 26, 2014.
Diameter:	150	ft	Based on project meeting between YCI, ENVIRON, and Air Liquide on September 26, 2014.
Annual Throughput:	308,639,340	gal/yr	Based on project meeting between YCI, ENVIRON, and Air Liquide on September 26, 2014.
Storage Temperature:	149	°F	Air Liquide, "69919-PR-00038 Air Permit Data Rev. 01.xlsx."
Number of Tanks:	1		Based on project meeting between YCI, ENVIRON, and Air Liquide on September 26, 2014.
Hours of Operation:	8,760	hr/yr	24 hr/day and 365 day/yr

Ex. D

TANKS Output per Tank

Pollutant	TANKS Emissions (lbs/yr)
Total VOC	6,387.08
Methanol	6,387.08

Emissions Summary

Pollutant	Average Emissions (lbs/hr)	Annual Emissions (tons/yr)
Total VOC	0.73	3.19
Methanol	0.73	3.19

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Methanol Loading Operations Emission Calculations

Signature: AMH
Checked: KNG

Source: Methanol Loading Operations
Source ID: RTLOAD and MLOAD

Date: 10/27/2014

Description:
The Methanol Loading Operations source accounts for the vapors generated during methanol product loading into tank trucks, rail cars, and marine vessels. Emissions from loading operations are minimized by a recovery or control device that achieves at least 98% reduction of VOC as methanol. The total annual methanol production for the facility is used to estimate emissions based on the worst case loading operation (i.e. railcar/tank truck).

Basis:		Source:
Operating Hours:	8,760 hr/yr	Total annual hours of operation.
Methanol Throughput:	308,639 Mgal/yr	Estimated total annual throughput for storage tanks. Air Liquide, "69919-PR-00038 Air Permit Data Rev. 01.xlsx."
Recovery Device VOC Control Efficiency:	98%	40 CFR 63 Subpart G

Loading Equation (AP-42 Chapter 5.2, Equation 1)

$L_L = 12.46 * (S*P*M/T) * (1\text{-vapor recovery eff\%})$

Where: L_L = Loading Loss Emission Factor (lb/Mgal)
S = Saturation Factor (AP-42 Table 5.2-1)
P = True Vapor Pressure of Product (psia)
M = Molecular Weight of Vapors (lb/lb-mol)
T = Temperature of Product (R)
eff% = Control Efficiency

Loading Emission Factors

Product	Railcar/Tank Truck Loading S[1]	Marine Loading S[2]	P[3] (psia)	M[3]	T		Railcar/Tank Truck Factor (lb/Mgal)	Marine Loading Factor (lb/Mgal)
					°F[3]	°R		
Methanol	0.6	0.5	5.08	32.04	104	564	2.16	1.80

Uncontrolled Vapors from Loading

Product	Emission Factor (lb/Mgal)[4]	Uncontrolled Vapor Rates	
		Average (lb/hr)	Annual (tpy)
Methanol	2.16	76.01	332.94

Controlled Emissions Summary

Pollutant	Controlled Emissions[5]		
	Average Emissions (lb/hr)	Maximum Emissions[6] (lb/hr)	Annual Emissions (tpy)
Methanol	1.52	5.32	6.66
VOC	1.52	5.32	6.66

Notes:
1. Conservatively assumed to be submerged loading of dedicated normal service.
2. Conservatively assumed to be submerged loading of barges.
3. Based on parameters from TANKS 4.09 for the Methanol Product Tanks.
4. To provide flexibility in loading operations, the most conservative factor between railcar/tank car loading and marine loading was chosen.
5. Controlled emissions utilize a 98% control efficiency from the recovery device.
6. Maximum emissions based on 3.5 times average to account for maximum pump rate during loading operations.

Ex. D

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Tank Landings Emission Calculations

Signature: AMH
Checked: _____

Source: Tank Landings
Source ID: _____

Date: 4/21/2015

Tank Landing Calculation

Description:
Emissions from tank landings were calculated using methodology from AP-42 Chapter 7.1. for Organic Liquid Storage Tanks. Emissions are based on conducting two landings per year with an average landing duration of 5 days. Emissions from tank landing are included as part of the Methanol Transfer and Storage CAP (MTSCAP).

Basis:

$L_T = L_{SL} + L_{FL}$

where, L_T = total losses during roof landing, lb per landing episode
L_{SL} = standing idle losses during roof landing, lb per landing episode
L_{FL} = filling losses during roof landing, lb per landing episode

5 number of days tank stands idle, n_d
0.018 vapor space expansion factor, dimensionless, K_E

K_E is the vapor space expansion factor = $(0.0018[T_{AX} - T_{AN}] + 0.028 \propto I)$
Where, $T_{AX} - T_{AN}$ is the daily vapor temperature range in degrees Rankine
$\propto$ is the tank pain t solar absorptance, dimensionless
I is the dailiy total solar insolation on a horizongal surface, Btu/ (ft²/day)

2.81 true vapor pressure of methanol, psia, **P**
32.04 methanol vapor molecular weight, lb/lb-mole, M_V
10.731 ideal gas constant, (psia-ft^3)/(lb-mole R), **R**
541.92 temperature, degrees Rankine, **T**
44178.65 volume of the vapor space, ft^3, V_V

0.50 saturation factor, dimensionless, K_S
0.5 filling saturation factor, dimensionless, **S**

$$L_{SL} = n_d K_E \left(\frac{PV_V}{RT}\right) M_V K_S$$

$$L_{FL} = \left(\frac{PV_V}{RT}\right) M_V S$$

Landing Summary per Event

Pollutant	Standing Idle Losses (L_{SL}) (lb/landing event)	Filling Losses (L_{FL}) (lb/landing event)
VOC	30.07	341.98
Methanol	30.07	341.98

Potential Total Landing Emissions (Assume two landings per tank for six tanks)

Pollutant	Emissions (lb/yr)	Emissions (lb/hr)	Emissions (tpy)
VOC	4464.69	0.51	2.23
Methanol	4464.69	0.51	2.23

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Tank Cleaning Emission Calculations

Signature: AMH
Checked: _____

Source: Tank Cleaning
Source ID: _____

Date: 4/21/2015

Description:
Tank Cleaning Emission Calculations are based on the API Technical Document 2568, November 2007. Emissions from tank cleaning are included as part of the Methanol Transfer and Storage CAP (MTSCAP).

Basis: $L_c = L_S + L_P + L_{SR} + L_F$

where

Lc	=	Total tank cleaning emisssions (lb/event)
L_S	=	Standing Idle Emissions
Lp	=	Vapor Space Purge Emissions
L_{SR}	=	Residue Removal Emissions
L_F	=	Refilling Emissions

Table 1.1: Internal Floating Roof Tanks Data

Tank ID	Methanol Tank
Tank Type	IFR
Tank Service	Methanol
RVP	--
Vapor Pressure (psia), [a]	2.81
Tank Diameter (ft),	50
Vapor Molecular Weight [b] (lb/lbmole),	32.04
Average Temperature (F),	82.3
Number of days Tank stands idle	2.00
Deck Leg Height	3.00
Effective Liquid Height	0.50
Number of days for Residue Removal	7.00

(a) The vapor pressure for tanks containing methanol was calculated using Antoine's equation, the coefficients were taken from TANKS 4.09d and AP-42 Supplement D, Table 7-1.5.
(b) The vapor molecular weight data for methanol was taken from U.S. EPA Report AP-42, Fifth Edition, Supplement D, Table 7.1-3.

Table 1.2: Standing Idle Emissions, L_S, for Internal Floating Roof Tank

Tank ID		Methanol Tank
Tank Type		IFR
Tank Service	Units	Methanol
L_S	lb/event	**8.97**
V_V	ft^3	4908.74
D	ft	50.00
h_v	ft	2.50
ΔT_V	R	20.00
P_a	psia	14.73
K_E	dimensionless	0.08
K_S	dimensionless	0.73
M_V	lbs/lb-mole	32.04
T	Rankine	541.97

Standing Idle Emissions, L_S, Equations for Table 1.2 (Internal Floating Roof Tank)

$$L_S = n_d K_E \left(\frac{PV_V}{RT}\right) M_V K_S$$

where R = 10.731 psia · ft^3/lb · mole × R, ideal gas constant
n_d = number of days the tank stands idle

V_V is the volume of the vapor space = $(h_v)(\pi d^2/4)$
where, h_v is the height of the vapor space = $h_d - h_l$ (Deck leg height - height of liquid); both are defined in

K_E is the vapor space expansion factor = $\frac{\Delta T_V}{T}\left(1 + \frac{0.50BP}{T(P_a - P)}\right)$
where, ΔT_V is the daily vapor temperature range in degrees Rankine
P_a is the atmospheric pressure at the tank location in psia

K_S is the standing idle saturation factor (dimensionless) = $\frac{1}{1 + 0.053P(h_v)}$
where , h_v is the height of the vapor space = $h_d - h_l$

M_V, T are both defined in Table 1.2 as the vapor molecular weight and average temperature.

Ex. D

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Tank Cleaning Emission Calculations

Signature: AMH
Checked: _____

Source: Tank Cleaning
Source ID: _____

Date: 4/21/2015

Table 1.3: Vapor Space Purge Emissions, Lp, for Internal Floating Roof Tank

Tank ID		Methanol Tank
Tank Type		IFR
Tank Service	Units	Methanol
L_P	lb/event	**37.98**
V_V	ft^3	4908.74
h_V	ft	2.50
S	dimensionless	0.50
M_V	lbs/lb-mole	32.04
T	Rankine	541.97

Vapor Space Purge Emissions, Lp, Equations for Table 1.3 (Internal Floating Roof Tanks)

$$L_P = \left(\frac{PV_V}{RT}\right) M_V S$$

where, R = 10.731 psia · ft^3/lb · mole × R, ideal gas

V_V is the volume of the vapor space = $(h_v)(\pi d^2/4)$

where, h_v is the height of the vapor space = $h_d - h_l$ (Deck leg height - height of liquid); both are defined in Table 1.3

S is the filling saturation factor = 0.6 for IFRTs

M_V, T are both defined in Table 1.3 as the vapor molecular weight and average temperature.

Table 1.4: Residue Removal Emissions, LSR, for Internal Floating Roof Tanks

Tank ID		Methanol Tank
Tank Type		IFR
Tank Service	Units	Methanol
L_{SR}	lb/event	**498.69**
P^*	dimensionless	0.08
P_a	psia	14.73
M_V	lbs/lb-mole	32.04
D	ft	50.00

Residue Removal Emissions, LSR , Equations for Table 1.4 (Internal Floating Roof Tanks)

Internal Floating Roof Tanks and Vertical Fixed Roof Tanks

$$L_{SR} = 0.57 n_{SR} D P^* M_V$$

n_{SR} is the time for sludge removal in days

P^* is a vapor pressure funcion (dimensionless) = $\frac{P/P_a}{\{1+[1-P/P_a]^{0.5}\}^2}$

M_V, D are both defined in Table 1.4, as the vapor molecular weight and tank diameter

ENVIRON

Yuhuang Chemical Inc.
Louisiana Methanol Plant Project
Tank Cleaning Emission Calculations

Signature: AMH
Checked: _____

Source: Tank Cleaning
Source ID: _____

Date: 4/21/2015

Table 1.5: Refilling Emissions, L_F , for Internal Floating Roof Tanks.

Tank ID		Methanol Tank
Tank Type		IFR
Tank Service	Units	Methanol
L_F	lb/event	11.39
V_V	ft^3	4908.74
h_V	ft	2.50
S	dimensionless	0.15
M_V	lbs/lb-mole	32.04
T	Rankine	541.97
D	ft	50.00

Refilling Emissions, L_F , Equations for Table 1.5 (Internal Floating Roof Tanks)

$$L_F = \left(\frac{PV_V}{RT}\right) M_V S$$

where, S = 0.15

V_V is the volume of the vapor space = $(h_v)(\pi d^2/4)$
where, h_v is the height of the vapor space, = $h_d - h_l$
S is the filling saturation factor = 0.15 for Refilling Emissions
M_V, T are both defined in Table 1.5, as the vapor molecular weight and average temperature

Table 1.6: VOC Emissions for One Tank Cleaning, Lc.

$L_c = L_S + L_P + L_{SR} + L_F$

Tank ID		Methanol Tank
Tank Type		IFR
Tank Service	Units	Methanol
L_S	(lbs/yr)	8.97
L_P	(lbs/yr)	37.98
L_{SR}	(lbs/yr)	498.69
L_F	(lbs/yr)	11.39
L_C	(lbs/yr)	**557.02**
L_C	(tpy)	**0.28**

Total tank cleaning emissions, one cleaning per tank per year for six tanks.			
	Annual Emissions (lb/yr)	Average Emissions (lb/hr)	Annual Emissions (tpy)
VOC	3342.14	0.38	1.67
Methanol	3342.14	0.38	1.67

Attachment B

Updated EIQ Sheets

State of Louisiana
Emissions Inventory Questionaire (EIQ) for Air Pollutants

Date of Submittal: December 2014

Emission Point ID No. (Alternate ID)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FLR	Flare	Method: 18,"Interpolation - Map" Datum: NAD83
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 706154 mE Vertical: 3318326 mN
		Latitude: 29 ° 58 ' 42 " 589 hundredths
		Longitude: 90 ° 51 ' 47 " 665 hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Thoughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
No	0.54 ft / ft ²	195 ft	65.6 ft/sec	917 ft^3/min	1832 °F	8760 hr/yr	2015	25	25	25	25

Ex. D

Fuel	Type of Fuel Used and Heat Input (see instructions)	
	Type of Fuel	Heat Input (MMBTU/hr)
Notes		

Operating Parameters (include units)		
	Parameter	Description
Normal Operating Rate/Throughput		
Maximum Operating Rate/Throughput		
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		
Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal		
Date Engine Ordered		Engine Model Year
Date Engine Was Built by Manufacturer		
SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke		

Air Pollutant Specific Information

Emmision Point ID No. (Alternate ID): FLR	Control Equipment Code	Control Equipment Efficiency	HAP/TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration of gases exiting at stack
Pollutant				Average (lbs/hr)	Max (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
CARBON MONOXIDE				0.45	44.25	1.98		Add		
NITROGEN OXIDES				1.66	184.46	7.25		Add		
PARTICULATE MATTER				0.01	1.10	0.05		Add		
PM10				0.01	1.10	0.05		Add		
PM2.5				0.01	1.10	0.05		Add		
SULFUR DIOXIDE				0.05	5.30	0.21		Add		
TOTAL VOC (INCL. LISTED)				0.31	1.76	1.35		Add		
METHANOL			67-56-1	0.03	1.76	0.15		Add		

State of Louisiana
Emissions Inventory Questionaire (EIQ) for Air Pollutants

Date of Submittal: December 2014

Emission Point ID No. (Alternate ID)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FUG	Fugitive Emissions	Method: 18,"Interpolation - Map" Datum: NAD83
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 705838 mE Vertical: 3318056 mN
		Latitude: 29 ° 58 ' 34 " 14 hundredths
		Longitude: 90 ° 51 ' 69 " 637 hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Thoughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
No	ft / ft^2	ft	ft/sec	ft^3/min	°F	8760 hr/yr	2015	25	25	25	25

Fuel	Type of Fuel Used and Heat Input (see instructions)	
	Type of Fuel	Heat Input (MMBTU/hr)

Notes

Operating Parameters (include units)		
	Parameter	Description
Normal Operating Rate/Throughput		
Maximum Operating Rate/Throughput		
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered | Engine Model Year

Date Engine Was Built by Manufacturer

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Air Pollutant Specific Information

Emmision Point ID No. (Alternate ID) / Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP/TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration of gases exiting at stack
				Average (lbs/hr)	Max (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
FUG										
CARBON MONOXIDE				0.03		0.14		Add		
TOTAL VOC (INCL. LISTED)				1.03		4.50		Add		
METHANOL			67-56-1	0.98		4.31		Add		
AMMONIA			7664-41-7	0.01		0.03		Add		

Ex. D

State of Louisiana
Emissions Inventory Questionaire (EIQ) for Air Pollutants

Date of Submittal: December 2014

Emission Point ID No. (Alternate ID)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
MTSCAP	Methanol Transfer and Storage CAP	Method: Datum:
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: mE Vertical: mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
No	ft / ft^2	ft	ft/se	ft^3/min	°F	0 hr/yr	2015	25	25	25	25

Fuel	Type of Fuel	Heat Input (MMBTU/hr)

Notes

The MTSCAP source includes Methanol Product Tanks (EPNs TK-26-202A through TK-26-202E), Crude Methanol Tank (EPN TK-26-201), and Methanol Loading Operations (EPNs MLOAD and RTLOAD).

Operating Parameters (include units)	Parameter	Description
Normal Operating Rate/Throughput		
Maximum Operating Rate/Throughput		
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered: Engine Model Year:

Date Engine Was Built by Manufacturer:

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Air Pollutant Specific Information

Emmision Point ID No. (Alternate ID) / Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP/TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration of gases exiting at stack
				Average (lbs/hr)	Max (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
MTSCAP										
TOTAL VOC (INCL. LISTED)				4.52		19.80		Add		
METHANOL			67-56-1	4.52		19.80		Add		

Ex. D

UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY
REGION 9

In the Matter of:	)	
	)	
Bakersfield Crude Terminal LLC	)	Docket No. R9-15-08
Plains Marketing, L.P.	)	
Plains All American Inc.	)	Finding and Notice of Violation
Taft, California	)	
	)	
Proceeding Under Section 113(a),	)	
Clean Air Act, As Amended	)	

This Finding and Notice of Violation ("NOV") is issued to Bakersfield Crude Terminal LLC ("BCT"), Plains Marketing, L.P. ("PMLP"), and Plains All American Inc. ("PAAI") for violations of the Clean Air Act (the "Act") as amended, 42 U.S.C. §§ 7401-7671q, at their crude oil railcar-to-pipeline transfer and storage terminal located at or near South Lake Road and Santiago Road, Taft (Kern County), California (the "Facility"). The Facility is located within the jurisdiction of the San Joaquin Valley Air Pollution Control District ("SJVAPCD" or "District"). Section 113(a)(1) of the Act requires the Administrator of the Environmental Protection Agency ("EPA") to notify a person in violation of a state implementation plan ("SIP"). The authority to issue NOVs has been delegated to the Director of the Enforcement Division for EPA, Region IX.

I. STATUTORY AND REGULATORY BACKGROUND

A. General Provisions

1. Section 110(a) of the Act requires that all states adopt a SIP that provides for the implementation, maintenance and enforcement of primary and secondary air quality standards. 42 U.S.C. §7410(a).
2. A person's failure to comply with any approved regulatory provision of a SIP renders the person subject to enforcement under section 113 of the Act. 42 U.S.C. §7413(a)(1); 40 C.F.R. §52.23.

B. SJVAPCD Rule 2010 Permits Required

3. In accordance with section 110 of the Act, EPA has approved Rule 2010 ("Permits Required"), as adopted on December 17, 1992, into SJVAPCD's portion of the California SIP. 64 Fed. Reg. 39920 (July 23, 1999). 40 C.F.R. § 52.220(c)(199)(i)(D)(6).

4. Section 3.0 of Rule 2010 requires that any person who builds, alters, or replaces any equipment which may emit air pollution must first obtain a valid Authority to Construct ("ATC").

5. Section 4.0 of Rule 2010 requires that a valid Permit to Operate ("PTO") must be obtained prior to the operation of any source described in section 3.0 of Rule 2010.

C. SJVAPCD Rule 2201 New and Modified Stationary Source Review Rule

6. In accordance with section 110 of the Act, EPA has approved Rule 2201 ("New and Modified Stationary Source Review Rule"), as adopted on May 21, 2011, into SJVAPCD's portion of the California SIP. 79 Fed. Reg. 55637 (September 17, 2014). 40 C.F.R. § 52.220(c)(400)(i)(A)(1).

7. Section 4.0 of Rule 2201 requires "Best Available Control Technology" ("BACT"), on a pollutant-by-pollutant and emissions unit-by-emissions unit basis, for a new emissions unit with a potential to emit ("PTE") greater than 2.0 pounds per day.

8. Section 3.10 of Rule 2201 defines BACT as the most stringent emission limitation or control technique that has been achieved in practice or required by any SIP for the same class or category as the source.

9. Section 4.5.3 of Rule 2201 requires offsets for new a facility which has the PTE 20,000 pounds or more per year of volatile organic compounds ("VOC").

10. Pursuant to section 3.24 of Rule 2201, if a new stationary source has a PTE of 20,000 pounds or more per year of VOC, it is considered a major stationary source of air pollution.

11. Section 4.14.1 of Rule 2201 requires that an air quality analysis be performed to assure that a new major stationary source of air pollution will not cause or make worse a violation of a state or national ambient air quality standard.

12. Section 4.15.1 of Rule 2201 requires that "For those sources for which an analysis of alternative sites, sizes, and production processes is required under Section 173 of the Federal Clean Air Act, the applicant shall prepare an analysis functionally equivalent to the requirements of Division 13, Section 21000 et. seq. of the [California] Public Resources Code."

13. Section 5.4 of Rule 2201 requires that public notification and publication shall be provided for new major stationary sources of air pollution.

14. Section 5.6.1 of Rule 2201 states that: "An ATC shall not be issued unless the new or modified source complies with the provisions of this rule and all other applicable District Rules and Regulations."

15. Section 5.7.2 of Rule 2201 states that: "A PTO shall include daily emissions limitations and other enforceable conditions which reflect applicable emission limits including the offset requirements."

D. Requirements for a Valid Synthetic Minor Source Permit

16. Pursuant to the Act and Rule 2201, a proposed new stationary source which has a PTE over the major source threshold can request permit conditions which lower its PTE. A permit which contains these conditions and lowers the PTE of a proposed new source below the major source threshold is known as a "synthetic minor source permit." The approach to creating a synthetic minor source permit is reflected in the definition of PTE set forth in section 3.27 of Rule 2201:

> Potential to Emit: the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including pollution control equipment and restrictions in hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is incorporated into the applicable permit as an enforceable permit condition.

17. To be an "enforceable permit condition" and thus be used to limit the PTE of a source, the permit condition must be federally enforceable or legally and practicably enforceable by a state or local air pollution control agency. See, Chemical Manufacturers Ass'n v. EPA, 70 F.3d 637 (D.C. Cir. Sept. 15, 1995); National Mining Association v. EPA, 59 F.3d 1351 (D.C. Cir. July 21, 1995); and 40 C.F.R. § 51.165(a)(1)(iii). See also, *In the Matter of Hu Honua Bioenergy Facility*, Order on Petition No. IX-2011-1 (February 7, 2014).

II. FINDINGS OF FACT

18. BCT is registered with the California Secretary of State as a foreign limited liability company and is the original applicant for ATCs for the Facility.

19. PMLP is registered with the California Secretary of State as a foreign limited partnership. According to a communication from Glen Mears of PLMP to the SJVAPCD, PLMP acquired all assets of BCT, including BCT's name.

20. PAAI is registered with the California Secretary of State as a foreign corporation. PAAI is listed as a

partner in PMLP.

21. Some combination of BCT, PMLP, and PAAI own and/or operate the Facility ("Facility Owners/Operators").

22. The Facility is located within the jurisdiction of the SJVAPCD.

23. The Facility is capable of operating 24 hours per day, 7 days per week, and every day of the calendar year. The Facility has been in operation since sometime in 2014.

24. The Facility consists of two rail spurs to receive and offload up to two unit trains per day (a unit train usually consists of between 104 and 120 railcars), two 150,000-barrel internal floating roof tanks to store the crude oil, a crude oil unloading rack that individually unloads each rail car, pump pits, transfer and booster pumps, connecting pipelines, and other ancillary equipment.

25. On May 16, 2012, BCT submitted an application for an ATC ("2012 Application") for the Facility to the SJVAPCD. On July 25, 2012, the SJVAPCD issued a review of the 2012 Application ("2012 Application Review"). In the 2012 Application Review, the SJVAPCD calculated the PTE for the Facility to be 19,992 pounds per year. This PTE is based upon claims from BCT that the Reid vapor pressure ("RVP") being unloaded from railcars at the Facility would not, on average, exceed 8.3 pounds per square inch absolute ("psia").

26. The PTE calculations in the 2012 Application Review did not include emissions referred to as "roof landing losses" for internal floating roof tanks. Roof landing losses occur regularly in the petroleum industry when internal floating rood tanks are emptied to the point that the floating roof touches down on its support legs. Roof landings of internal floating roof tanks result in extra emissions of VOCs occurring compared to those emissions when the internal roof is floating on the liquid in the tank.

27. On July 31, 2012, the SJVAPCD issued ATCs ("2012 ATCs") to BCT for the Facility's internal floating roof storage tanks, unloading rack, and other associated equipment, permitting BCT to process any crude oil with an RVP of less than 11.0 psia at the Facility although SJVAPCD used an average RVP of 8.3 psia to calculate the PTE of the facility in its 2012 Application review.

28. The 2012 ATCs for the two internal floating roof storage tanks contain identical provisions purporting to

require an average RVP of 8.3 psia for crude oil processed at the Facility: "If any shipment of organic liquid with an RVP of greater than 8.3 psia is introduced, placed, or stored in this tank in any calendar year, compliance with the annual combined emission limit for tanks listed on S-8165-1 '-2 shall be demonstrated by calculating and maintaining an annual emissions summary using the EPA's TANKS program."

29. The 2012 ATCs do not require any testing of the RVP of the crude oil processed at the Facility to determine if the RVP of the crude oil processed by BCT is less than 11.0 psia or which could be used by BCT to show that the average annual RVP of crude oil processed at the Facility was no greater than 8.3 psia and therefore complied with the limits on VOC emissions contained in the 2012 ATCs.
30. The 2012 ATCs do not require any enforceable operational requirements or monitoring to ensure that the Facility will have an annual average RVP of no greater than 8.3 psia, which is the assumed average RVP for determining that the facility emits less than 20,000 pounds per year.
31. Geodesic domes have been installed in the United States which enclose tanks storing petroleum liquids. These domes lower emissions from the tanks. Since this control technology has been achieved in practice, it is BACT for these types of tanks. The tanks at the Facility are not enclosed by geodesic domes.
32. During the permitting process, both BCT and the SJVAPCD acknowledged that without limits on the Facility's ability to emit VOC, the Facility would be a major source of VOC emissions pursuant to Rule 2201.
33. No offsets have been provided for the Facility as required by section 4.5 of Rule 2201.
34. No air quality analysis as required by section 4.14.1 of Rule 2201 has been performed for emissions from the Facility.
35. No analysis functionally equivalent to the requirements of Division 13, Section 21000 et. seq. of the California Public Resources Code has been performed with regard to the Facility.
36. No public notification or publication of the 2012 ATCs occurred as required by section 5.4 of Rule 2201.
37. On March 18, 2013, Glen Mears of PMLP (with the title of "Sr. Environmental RC Specialist") resubmitted the 2012 Application for the Facility, claiming that while PMLP had acquired all assets of BCT, including BCT's name, PLMP believed that the 2012 ATCs issued to BCT could not otherwise be transferred and

must be re-issued.

38. On September 8, 2014, Glen Mears, acting on behalf of BCT/PLMP but communicating on stationary bearing the letterhead of Plains LPG Services, L.P., submitted another application for an ATC to the SJVAPCD. This ATC application was for installation of four fixed roof tanks and an oil/water separator. These emission units were not included in the 2012 Application and not considered in the SJVAPCD 2012 Application review that determined that the PTE of the Facility was 19,992 pounds per year for VOC emissions. SJVAPCD issued the ATC for these additional units on September 23, 2014 ("2014 ATC"). The potential VOC emissions from these units were not added to the PTE VOC emissions for the Facility.

39. The RVP of a liquid such as crude oil determines its emissions rate. When stored in the same type of tank and under similar conditions (e.g., ambient air temps) crude oil with a higher RVP will emit more VOC emissions than crude oil with a lower RVP.

40. Pursuant to the 2012 and 2014 ATCs, the Facility is allowed to receive crude oil from the Bakken formation.

41. In August 2014, The North Dakota Petroleum Council issued a report that shows the average RVP for Bakken crude oil is 11.5 psia.

42. In May 2014, the American Fuel and Petrochemical Manufacturers ("AFPM") submitted a report to the U.S. Department of Transportation that showed that Bakken crude oil has a seasonal high average of 12.5 psia. Data from the AFPM report show that the RVP of Bakken crude oil can vary from below 5.0 psia to over 15.0 psia.

43. Reports such as the ones from the North Dakota Petroleum Council and the American Fuel and Petrochemical Manufacturers show that an RVP of 8.3 psia submitted in the BCT applications for ATC is 28 to 34 percent below the averages found in the reports from these trade associations.

III. FINDINGS OF LAW

44. The permit provisions in the 2012 ATC for the Facility are not enforceable as a practical matter and, therefore, cannot limit the Facility's PTE because an annual emission limit of 19,992 pounds of VOC, without a comprehensive and enforceable methodology (i.e., monitoring, reporting and recordkeeping) on a

more frequent than an annual basis, is not sufficient to ensure that the Facility emits less than 20,000 pounds of VOC emissions a year and remains a minor source.

45. The provisions in the 2012 ATCs and the 2014 ATC that allow the Facility to receive crude oil shipments with an RVP of anything less than 11.0 psia is not enforceable as a practical matter based on the operations of the Facility because this limit cannot ensure that the annual VOC emissions are less than 20,000 pounds per year. This "shipment" based limit of 11 psia is 33 percent greater than the 8.3 psia used as the basis for the Facility's PTE in the 2012 Application and 2012 Applicability analyses. Using the 10.9 psia (which is less than 11.0 psia) on an annual basis results in VOC emissions of greater than 25,900 pounds per year from the units permitted in the 2012 ATC alone (i.e., these emissions do not include the emissions from the additional 5 emission units permitted in the 2014 ATC). Given the wide variations in RVP for the crude oil that can be received at the Facility, and the annual emissions estimate of 19,992 pounds per year (or 99.96 percent of the major source threshold) for the emission units permitted in the 2012 ATCs, testing and/or monitoring provisions for the RVP from the crude oil shipments are required to ensure that the facility emits less than 20,000 pounds of VOC emissions in a year and remain a minor source. Without enforceable limits, the Facility's annual PTE for VOC emissions is equal to or greater than 20,000 pounds per year.
46. The PTE calculations used in the 2012 Application Review to determine the Facility's minor source status incorrectly underestimated the emissions from the floating roof tanks installed at the Facility. As set forth in the 2012 ATCs for the storage tanks at the Facility and as experienced in the petroleum industry, internal floating roof tanks are regularly emptied to the point that the floating roof touches down on its support legs. In a roof landing event, substantial amounts of VOC emissions occur, and these emissions are referred to as "roof landing losses." A proper engineering analysis includes roof landing losses in the PTE for a petroleum storage tank. The PTE calculations used to determine the Facility's minor source status omitted roof landing losses for the internal floating roof tanks.
47. Inclusion of the additional VOC emissions from the internal floating roof landing would result in an annual PTE for the Facility of 20,000 pounds or more per year of VOC.
48. The emission calculations for the additional units in the 2014 ATC (i.e., the four sump tanks and the

oil/water separator) were improperly excluded from the Facility's PTE. The VOC emissions from these units (after being controlled by a carbon canister system) was calculated to be 509 pounds per year collectively or 1.4 pounds per day for all five units. However, these VOC emissions were "rounded down" to zero and not included in the Facility's PTE in view of SJVAPCD policy APR 1130 that excludes new units with emissions of 0.54 pounds per day or less from a facility's PTE calculations. The exclusion of these VOC emissions from PTE calculations is nether approved under the SIP nor legitimate under the Act. Rounding down daily emissions might be acceptable under some limited circumstances, e.g., a rule establishes the emissions threshold for new units requiring BACT at one pound per day and a new emission unit will have emissions of less than 0.50 pounds per day. However, rounding down per day emissions to eliminate these emissions from annual PTE calculations is not an acceptable practice.

49. Inclusion of the additional VOC emissions from the five additional units in the 2014 ATC would result in an annual PTE for the Facility of 20,000 pounds or more per year of VOC.

50. If the Facility has a PTE of 20,000 pounds or more of VOC per year, it is considered a major source under section 3.24 of Rule 2201.

51. As a major source, the Facility is, pursuant to Rule 2201, required to have a valid ATC and a subsequent valid PTO which contain the requirements for a major source.

52. BACT has not been installed on all emissions units at the Facility that are subject to the requirement in Rule 2201 to install BACT.

IV. FINDINGS OF VIOLATION

Findings of Failure to Comply with Rules 2010 and 2201

53. The Facility Owners/Operators are in violation of Section 3.0 of Rule 2010 because they failed to obtain a valid ATC for a major source of VOC emissions prior to building the Facility.

54. The Facility Owners/Operators are in violation of Section 4.0 of Rule 2010 because they failed to obtain a valid PTO for a major source of VOC emissions prior to operating the Facility.

55. The Facility Owners/Operators are in violation of Section 4.1 of Rule 2201 because they failed to obtain a valid ATC and subsequent PTO which comply with Rule 2201's BACT requirements prior to building the Facility.

56. The Facility Owners/Operators are in violation of Section 4.5.3 of Rule 2201 because they failed to obtain VOC offsets for the Facility prior to commencing operation of the Facility.

57. The Facility Owners/Operators are in violation of Section 4.14.1 of Rule 2201 because they failed to obtain an ATC and subsequent PTO based upon an ambient air quality analysis showing that the Facility would not cause or make worse an exceedance of a state or national ambient air quality standard.

58. The Facility Owners/Operators are in violation of Section 4.15.1 of Rule 2201 because they failed to obtain an ATC and subsequent PTO based upon an analysis functionally equivalent to the requirements of Division 13, Section 21000 et. seq., of the Public Resources Code.

59. The Facility Owners/Operators are in violation of Section 5.4 of Rule 2201 because they failed to obtain an ATC and subsequent PTO which were issued after compliance with the public notification and publication requirements in that section.

60. The Facility Owners/Operators are in violation of Section 5.6.1 of Rule 2201 because they failed to obtain an ATC which complied with all requirements of Rule 2201.

61. The Facility Owners/Operators are in violation of Section 5.7.2 of Rule 2201 because they failed to obtain a PTO that contains enforceable conditions which reflect emissions limits applicable to the Facility.

62. The Facility Owners/Operators remain and will continue to be in violation of Rules 2010 and 2201 until they obtains a valid ATC and valid PTO for the Facility and fully complies with the conditions set forth in the valid ATC and valid PTO.

V. NOTICE OF VIOLATION

Notice is given to the Facility Owners/Operators that the Administrator of the EPA, by authority duly delegated to the undersigned, finds the Facility Owners/Operators are in violation of section 110 of the Act, the California SIP, and SJVAPCD Rules 2010 and 2201, as set forth in the Findings of Violation.

VI. ENFORCEMENT

Section 113(a)(1) of the Act provides that when any person has violated any requirement or prohibition of an applicable implementation plan or permit, EPA may:

- issue an order requiring compliance with the requirements or prohibition of such implementation plan or permit, or
- issue an administrative penalty order pursuant to section 113(d) for civil administrative penalties of up to $37,500 per day of violation, or
- bring a civil action pursuant to section 113(b) for injunctive relief and/or civil penalties of not more than $37,500 per day for each violation.

Furthermore, if a person knowingly violates any requirements of an applicable implementation plan more than 30 days after notification of violation, section 113(c) provides for criminal penalties or imprisonment, or both.

Under section 306(a) of the Act, the regulations promulgated thereunder (40 C.F.R. Part 15), and Executive Order 11738, facilities to be used in federal contracts, grants, and loans must be in full compliance with the Act and all regulations promulgated pursuant to it. Violations of the Act may result in the facility being declared ineligible for participation in any federal contract, grant, or loan.

VII. PENALTY ASSESSMENT CRITERIA

Section 113(e)(1) of the Act states that the Administrator or the court, as appropriate, shall, in determining the amount of any penalty to be assessed, take into consideration (in addition to such other factors as justice may require) the size of the business, the economic impact of the penalty on the business, the violator's full compliance history and good faith efforts to comply, the duration of the violation as established by any credible evidence (including evidence other than the applicable test method), payment by the violator of penalties previously assessed for the same violation, the economic benefit of noncompliance, and the seriousness of the violation.

Section 113(e)(2) of the Act allows the Administrator or the court to assess a penalty for each day of violation. For the purposes of determining the number of days of violation, where the EPA makes a prima facie

showing that the conduct or events giving rise to this violation are likely to have continued or recurred past the date of this NOV, the days of violation shall be presumed to include the date of this NOV and each and every day thereafter until the violator establishes that continuous compliance has been achieved, except to the extent that the violator can prove by the preponderance of the evidence that there were intervening days during which no violation occurred or that the violation was not continuing in nature.

VIII. OPPORTUNITY FOR CONFERENCE

The Facility Owners/Operators may, upon request, confer with EPA. The conference will enable the Facility Owners/Operators to present evidence bearing on the finding of violation, the nature of the violation, and any efforts they may have taken or proposes to take to achieve compliance. The Facility Owners/Operators have the right to be represented by counsel. A request for a conference with EPA must be made within ten (10) working days of receipt of this NOV. The request for a conference or other inquiries concerning the NOV should be made in writing or via email to:

Allan Zabel
Office of Regional Counsel (ORC-2)
U.S. Environmental Protection Agency
75 Hawthorne Street
San Francisco, California 94105
(415) 972-3902
zabel.allan@epa.gov

APR 30 2015

Date

Kathleen H. Johnson
Director, Enforcement Division

Ex. E

Report on Bakersfield Crude Terminal Permits to Operate
Phyllis Fox, Ph.D., PE
12/24/2014

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INTRODUCTION

On May 16, 2012, Bakersfield Crude Terminal, LLC ("Applicant") submitted an Application for an Authority to Construct ("ACT") permit ("2012 Application") for the Bakersfield Crude Terminal ("Terminal") to the San Joaquin Valley Air Pollution Control District ("the District").[1] The Applicant requested expedited processing and worked with the District to reduce emissions below the major source threshold for volatile organic compounds (VOCs) to avoid Title V permitting and below the daily threshold to avoid public notice. The Authorities to Construct were issued July 31, 2012 for two 150,000 barrel (bbl) internal floating roof crude oil storage tanks and an organic liquid transfer operation with light crude oil railcar unloading rack and associated offloading, transfer and booster pumps.[2]

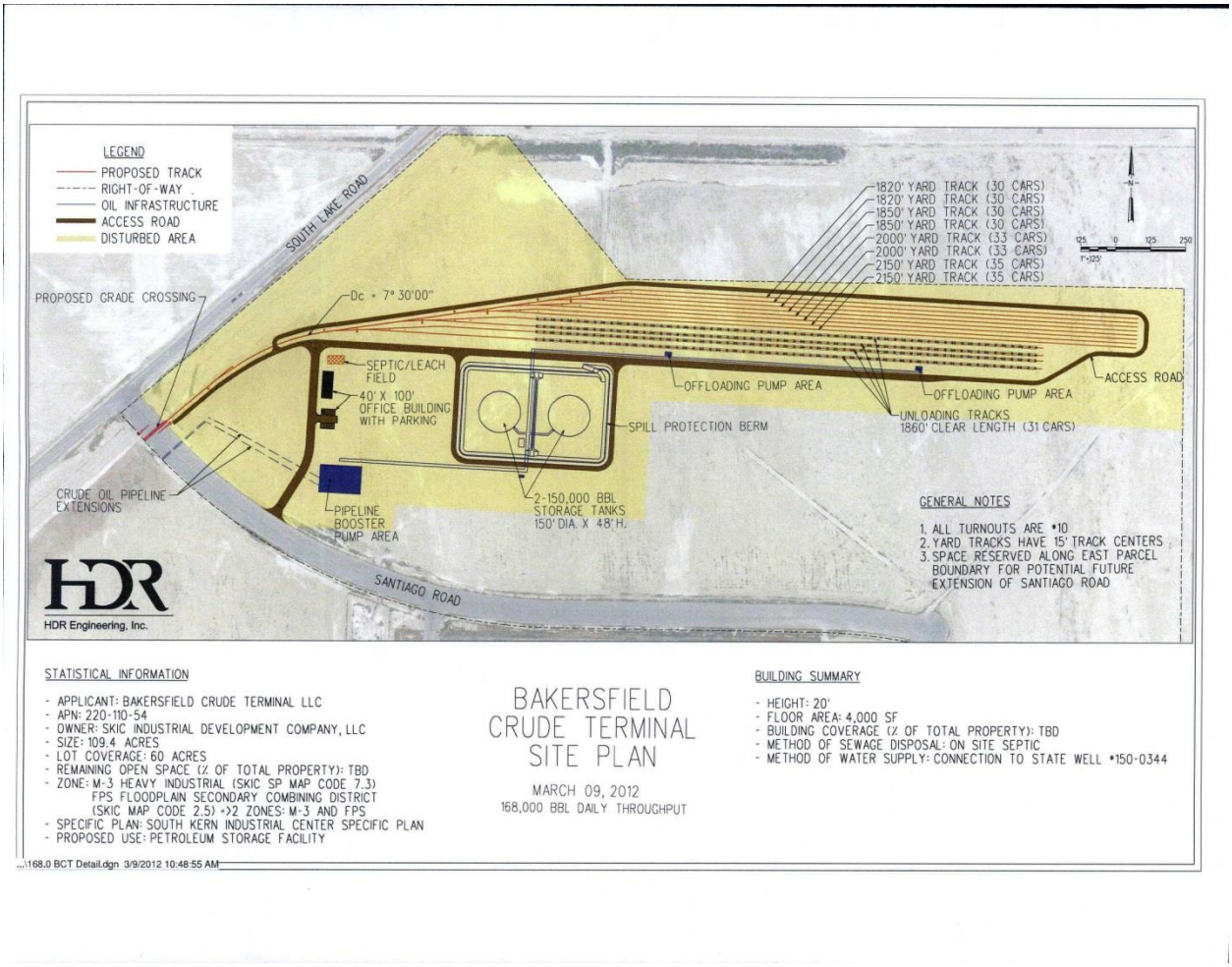
The proposed Terminal consisted of two rail spurs to receive and offload up to two unit trains per day of 104 rail cars each, two 150,000-barrel internal-floating-roof tanks to store the crude oil, a light crude oil unloading rack that individually unloads each car, and connecting pipelines. The loading rack was proposed to be 1800 feet by 44 feet wide and include 15 pump pits with pumps designed to be connected to four railcars each. The pumps were to be evenly distributed along the entire length of the loading rack so 120 rail cars could be simultaneously unloaded at full buildout.[3]

[1] HDR, Authority to Construction Application Package, Bakersfield Crude Terminal, LLC, Taft, CA, May 2012 ("2012 Terminal Application").

[2] SJVAPCD, Authority to Construct Permit Nos.: (1) S-8165-1-0 (150,000 bbl internal floating roof tank); (2) S-8165-2-0 (150,000 bbl internal floating roof tank); (3) S-8165-3-0 (liquid transfer operation with railcar unloading rack and associated offloading, transfer and booster pumps), July 31, 2012.

[3] E-mail from Joe Henderson, RPMS Engineers, to Michael C. Ernst, SJVAPCD, Re: Follow-up on Tank Questions for Crude Oil Terminal, June 25, 2012; E-mail from K. Rickard to K. Thao, Re: RO RMR Project for Bakersfield Crude, June 25, 2012.

Figure 1 - Facility Design



The Facility was to be designed for a maximum throughput of 168,000 bbd/day or 61,320,000 bbl/yr. The proposed maximum combined throughput for both tanks was 168,000 bbl/day or 25,550,000 bbl/yr. The balance of the crude oil (61,320,000 – 25,550,000 = 35,770,000 bbl/yr) would bypass the tanks and be delivered directly to the pipeline.[4] The Application identified a new 1.5 mile pipeline segment to connect the Facility with an existing pipeline, Plains Line 1.[5] The oil characteristics were described as having an API gravity of 43.3^{o} and a Reid Vapor Pressure (RVP) of 8.3 psia.[6]

Plains Marketing, L.P. acquired all of the assets, including the name, of the Bakersfield Crude Terminal LLC (BCT) and on March 18, 2013, re-submitted the ATC Application, without any changes, to transfer the title to Plains.[7]

[4] E-mail from Michael C. Ernst, HDR Inc. to Ashley Dahlstrom and Clint Meyer, SJVAPCD, Re: Additional Information Required, June 1, 2012.
[5] Kern County Planning and Community Development Dept., Notice of Intent to Adopt a Mitigated Negative Declaration for 5568TT; Nonexclusive Franchise Pipeline Agreement (Bakersfield Crude Terminal Pipeline Project by Bakersfield Crude Terminal, LLC (PP14145), March 27, 2014, pdf 119.
[6] 2012 Application, p. 1 & Attachs. B & C.
[7] Letter from Glen Mears, Plains Marketing, L.P., to Leonard Scandura, SJVAPCD, Re: Authority to Construct Application Bakersfield Crude Terminal, LLC, March 18, 2013

On September 8, 2014, Plains LPG Services, L.P, submitted an application for an Authority to Construct for four fixed roof tanks and an oil/water separator (Tanks/Separator Application), to be located at the Terminal. The Air District concluded that the addition of this new equipment did not increase emissions of VOC above the new source threshold, as their emissions were excluded using a District rounding policy (APR 1130).[8] The District issued ATCs for the new equipment on September 23, 2014.[9]

On October 16, 2014, Plains Marketing, L.P. submitted an application for an Authority to Construct for installation of two 399-hp emergency diesel-fueled, fire water pumps.[10] The Air District concluded that the addition of this new equipment did not increase VOC emissions above the new source threshold or the daily public notice threshold. In its Application Review for these fire water pumps, the Air District modified potential to emit calculations that it previously relied on to issue the July 13, 2012 Authorities to Construct for the Terminal, claiming fugitive emissions did not have to be included.[11]

THE BAKERSFIELDS CRUDE TERMINAL SHOULD HAVE BEEN PERMITTED AS A MAJOR SOURCE

The Bakersfield Crude Terminal emits volatile organic compounds (VOCs) from tanks; equipment leaks from valves, pumps, and connectors (fugitive emissions); and disconnect losses, as well as other sources not included in the District's analysis. To qualify as a minor source, VOC emissions must be less than 20,000 lb/yr.[12]

The District's July 25, 2012 Application Review[13] estimated volatile organic compound (VOC) emissions from two new 150,000 barrel internal floating roof crude oil storage tanks and an organic liquid transfer operation consisting of a railcar unloading rack and associated offloading transfer pipelines and booster pumps. The VOC emissions included in the District's calculations arise from tank breathing and working losses, fugitive components (valves, pump seals, connectors), and disconnect losses. The emissions were estimated as summarized in Table 1.

[8] SJVAPCD, Authority to Construct Application Review, Fixed Roof Tanks, September 20, 2014 (September 2014 Application Review).
[9] SJVAPCD, Authority to Construct Permit Nos.: (1) S-8165-9-0 (24 bbl fixed roof sump tank); (2) S-8165-10-0 (24 bbl fixed roof sump tank); (3) S-8165-11-0 (24 bbl fixed roof sump tank); (4) S-8165-12-0 (24 bbl fixed roof sump tank); (5) S-8165-13-0 (20,000 gallon oil/water separator).
[10] Letter from Glen Mears, Plains Marketing, L.P., to Leonard Scandura, SJVAPCD, Re: Authority to Construct Application Bakersfield Crude Terminal, LLC, October 16, 2014.
[11] SJVAPCD, Authority to Construct Application Review, Diesel-Fired Emergency Firewater Pump IC Engine, November 13, 2014 (November 2014 Application Review).
[12] Regulation 2201, Sec. 3.24.1.
[13] SJVAPCD, Authority to Construct Application Review, July 25, 2012 ("7/25/2012 Application Review").

Table 1
Bakersfield Crude Terminal VOC Emissions (ton/yr)

SSPE2 (lb/year)					
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC
S-8165-1-0	0	0	0	0	9,460
S-8165-2-0	0	0	0	0	9,460
S-8165-3-0	0	0	0	0	1,072
SSPE2	0	0	0	0	19,992

Potential to Emit Calculation from 7/25/2012 Application Review, p. 8

I. VOC Emissions Round Up To The Major Source Threshold

If VOC emissions equal or exceed 20,000 lb/yr, the facility is a major source.[14] The emissions from the Terminal were reported by the District to be 19,992 lb/yr.[15] This value rounds up to 20,000 lb/day. Thus, the Terminal should have been permitted as a major source in 2012.

The VOC emissions of 19,992 lb/yr were calculated from a number of inputs, which were all reported to only two significant figures, e.g., crude density of 7.1 lb/gal; disconnect volume of 3.2 mL per disconnect; valve emission factor of 4.3E-05 kg/hr; RVP = 8.3 psia. However, the results of the emission calculations is reported to five significant figures, *viz.*, 19,992 lb/yr. If the correct number of significant figures had been used in the VOC emission calculations, the VOC emission increase would equal 20,000 lb/yr, classifying the source as major. The District did not follow standard procedures for reporting results of calculations, taught in basic math, statistics and science courses and EPA air pollution courses.

The number of significant figures is simply the number of figures that are known with some degree of reliability. It is well established among professional engineers and scientists that the result of a calculation should be written with no more than the *smallest* number of significant figures of any of the factors included in the calculation, *viz.*, "The product often has a different precision than the factors, but the significant figures must not increase."[16] This is standard practice throughout the engineering and scientific professions.[17] This rule is taught in EPA air

[14] District Rule 2201, Sec. 3.24.
[15] 7/25/12 Application Review, p. 6.
[16] E.A. Avallone and T. Baumeister III (Eds.), Marks' Standard Handbook for Mechanical Engineers, 10th Ed., McGraw-Hill, New York, 1996, p. 2-4.
[17] See, *e.g.*, Philip R. Bevington, Data Reduction and Error Analysis for the Physical Sciences, McGraw-Hill, Inc., 1969, pp. 4, 9; Lothar Sachs, Applied Statistics. A Handbook of Techniques, 2nd Ed., Springer-Verlag, New York, 1984, p. 21.

pollution training courses.[18] The EPA Manual instructs: "When approximate numbers are multiplied or divided, the result is expressed as a number having the same number of significant digits as the expression in the problem having the least number of significant digits. In other words, if you multiply a number having four significant digits by a number having two significant digits, the correct answer will be expressed to two significant digits."[19] The Air District's Guidance APR 1105, *Guidelines for the Use of Significant Figures In Engineering Calculations* is in accord. The Guidance instructs that "Rounding off is accomplished by dropping the digits that are not significant. The digits 0, 1, 2, 3, and 4 are dropped without altering the preceding digit. The preceding digit is increased by one when a 5, 6, 7, 8, or 9 is dropped."

Thus, the results of the multiplications and additions used in the District's emission calculations should have been rounded off to the same number of significant figures as the factor with the least number of significant figures, which is two. Therefore, the results of the annual VOC calculations should have been reported to no more than **two** significant figures, corresponding to the number of significant figures in the underlying factors used in the calculations, not to **six** significant figures, or 19,992. Rounding 19,992 to two significant figures yields 20,000 lb/yr. This equals the major source significance threshold for VOC, classifying the Terminal as a major source under Rule 2201, Sec. 3.24.

II. Terminal VOC Emissions Were Underestimated

The 7/25/12 Application Review underestimated total VOC emissions from the Terminal by a significant amount due to several errors and omissions. The emissions from the Terminal, when operated at its maximum capacity based on its physical and operational design would emit more than 20,000 lb/yr of VOCs and thus would be a major source. Operational and other limitations were imposed in the ATC permits in an attempt to reduce VOC emissions to 19,992 lb/yr, just 8 lb/yr shy of the major source threshold. However, as explained below, the potential to emit calculations did not include all sources of emissions, which are thus not limited in the permits. Further, many of the conditions for emission sources that were included in the potential to emit calculations are not enforceable as they do not include adequate monitoring or any reporting.

A. Roof Landing, Degassing, and Cleaning Emissions Omitted

VOC emissions from the two new storage tanks were estimated using EPA's TANKS 4.0.9d model (TANKS).[20] However, this model only estimates rim seal losses, withdrawal losses, deck fitting losses, and deck seam losses. It does not estimate roof landing losses,

[18] U.S. EPA, APTI Virtual Classroom, Course SI 100: Mathematics Review for Air Pollution Control, Available at: Lesson 2 Significant Figures and Rounding off, Available at: http://yosemite.epa.gov/oaqps/EOGtrain.nsf/DisplayView/SI_100_0-5?OpenDocument; and Lesson 2, Available at: http://yosemite.epa.gov/oaqps/EOGtrain.nsf/fabbfcfe2fc93dac85256afe00483cc4/4939717614a0227e85256f400062252e/$FILE/Lesson2.pdf.

[19] EPA Manual, p. 2-5/2-6.

[20] 7/25/12 Application Review, Appx. E.

inspection losses, or flashing losses. Thus, it underestimated tank emissions. These emissions should be estimated and added to other tank emissions.

The Project includes two new internal floating roof tanks. The new tanks could be constructed with a leg-supported or self-supporting roof. The TANKS model input in Appendix E of the 7/25/12 Application Review indicates that the roofs are not self supported.[21] 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.[22] 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.[23]

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.[24]

The EPA recommends methods to estimate emissions from degassing and cleaning and roof landing losses.[25] 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

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[21] See, *e.g.*, 7/25/12 Application Review, Appx. E, 6/27/12 run, p. 1 of 5. (Self Supp. Roof? (y/n) = N).
[22] 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.").
[23] EPA, AP-42, Chapter 7.1 Organic Liquid Storage Tanks, November 2006; http://www.epa.gov/ttn/chief/ap42/ch07/final/c07s01.pdf.
[24] See EPA guidance on estimating these emissions at: http://www.epa.gov/ttnchie1/faq/tanksfaq.html#13 .
[25] "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 .

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.[26] They are required to be reported, for example, in Texas.[27] They are also included in the emission inventory of crude oil terminals.[28]

Tank roof landing emissions are large, typically comprising about 40% of total tank emissions. Thus, for the subject tanks, roof landing emissions alone could be 6,300 lb/yr. This is sufficient to classify the Terminal as a major source, just based on VOC emissions from the tanks.

Tank permit Condition 8 addresses roof landing emissions, but does not limit them. It only requires that "[w]hen the roof is resting on the leg support, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible." "As rapidly as possible" does not limit VOC emissions in an enforceable manner. Further, this condition also requires that "[w]henever the permittee intends to land the roof on its legs, the permittee shall notify the APCO in writing at least five days prior to performing the work." Similarly, notifying the District does not control VOC roof landing emissions.

Tank Permit Condition 34 additionally requires the permittee to maintain records of roof landing activities, but only those performed pursuant to Rule 4623, Sections 5.3.1.3 and 5.4.3. These records only have to be "maintained." There is no requirement that the records be reported to the District. Maintaining records does not limit VOC emissions. Further, the failure to report the records to the District limits the District's and affected parties' ability to estimate roof landing emissions to determine if emissions are large enough to qualify the Facility as a major source.

If the facility wishes to be a minor source, it should be required to control total tank emissions enough to reduce Terminal VOC emissions below the major source threshold. Emissions from degassing, cleaning, and roof landing losses can be reduced by greater than 95% by modifying the design of the tanks to include self-supporting roofs or to use external floating roof tanks, equipped with geodesic domes.

Geodesic domes are feasible, satisfy best available control technology (BACT), and are widely used. Over 10,000 aluminum domes have been installed on petrochemical storage tanks

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[26] 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

[27] 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 .

[28] 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 .

in the United States.[29] The ExxonMobil Torrance Refinery: "completed the process of covering all floating roof tanks with geodesic domes to reduce volatile organic compound (VOCs) emissions from facility storage tanks in 2008. By installing domes on our storage tanks, we've reduced our VOC emissions from these tanks by 80 percent. These domes, installed on tanks that are used to store gasoline and other similar petroleum-derived materials, help reduce VOC emissions by blocking much of the wind that constantly flows across the tank roofs, thus decreasing evaporation from these tanks."[30]

A tank crude storage capacity increase project, recently proposed at the Phillips 66 Los Angeles Carson Refinery, required external floating roof tanks with geodesic domes to store crude oil with an RVP of 11.[31] The ConocoPhillips Wilmington Refinery added a geodesic dome to an existing oil storage tank to satisfy BACT.[32] Similarly, Chevron proposes[33] to use domes on several existing tanks to mitigate VOC emission increases at its Richmond Refinery.[34] The U.S. Department of Justice CITGO Consent Decree required a geodesic dome on a gasoline storage tank at the Lamont, Texas refinery.[35] Further, numerous vendors have provided geodesic domes for refinery tanks.[36]

B. Pipeline Cleaning Emissions Omitted

A "pig" is a physical device used in pipelines during product transfer, product separation, and maintenance. The pig varies in size and shape and can be made of a variety of materials such as plastic, urethane foams, and rubber. Pigs can be solid, inflatable, foam, or made of a viscous gel. The Terminal includes a "pig launcher area,"[37] so pigging is anticipated and pigging emissions should have been included in the potential to emit calculations.

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[29] M. Doxey and M. Trinidad, Aluminum Geodesic Dome Roof for Both New and Tank Retrofit Projects, Materials Forum, v. 30, 2006, Available at: http://www.materialsaustralia.com.au/lib/pdf/Mats.%20Forum%20page%20164_169.pdf.

[30] Torrance Refinery: An Overview of our Environmental and Social Programs, 2010, Available at: http://www.exxonmobil.com/NA-English/Files/About_Where_Ref_TorranceReport.pdf.

[31] See, *e.g.*, Phillips 66 Los Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project, September 6, 2013, Table 1-1, Draft Negative Declaration, Available at: https://www.aqmd.gov/CEQA/documents/2013/nonaqmd/Draft_ND_Phillips_66_Crude_Storage.pdf

[32] SCAQMD Letter to G. Rios, December 4, 2009, Available at: http://yosemite.epa.gov/r9/air/epss.nsf/e0c49a10c792e06f8825657e007654a3/e97e6a905737c9bd882576cd0064b56a/$FILE/ATTTOA6X.pdf/ID%20800363%20ConocoPhillips%20Wilmington%20-%20EPA%20Cover%20Letter%20%20-AN%20501727%20501735%20457557.pdf.

[33] City of Richmond, Chevron Refinery Modernization Project, Environmental Impact Report, Volume 1: Draft EIR, March 2014 (Chevron DEIR), Available at: http://chevronmodernization.com/project-documents/ .

[34] Chevron DEIR, Chapter 4.3.

[35] CITGO Petroleum Corp. Clean Air Act Settlement, Available at: http://www2.epa.gov/enforcement/citgo-petroleum-corporation-clean-air-act-settlement.

[36] See, *e.g.*, Aluminum Geodesic Dome, Available at: http://tankaluminumcover.com/Aluminum-Geodesic-Dome; Larco Storage Tank Equipment, Available at: http://www.larco.fr/aluminum_domes.html; Vacono Dome, Available at: http://www.easyfairs.com/uploads/tx_ef/VACONODOME_2014.pdf; Peksay Ltd., Available at: http://www.peksay.info/oil_terminals/geodesic_domes.htm; United Industries Group, Inc., Available at: http://www.thomasnet.com/productsearch/item/10039789-13068-1008-1008/united-industries-group-inc/geodesic-aluminum-dome-roofs/;

[37] 1/17/2014 Application, Supplemental Information, p. 1

Pigging following product transfer is used to remove residual product from the pipeline after loading occurs. Pigs can also be used for product separation when switching products in the lines, as well as for maintenance activities such as pipeline cleaning, gauging, or dewatering. Pipeline blowdowns can occur during repair work or when lines are taken out of service. During pigging, a pig is inserted into the pipeline and forced through by a compressed gas, such as nitrogen. When the pig gets to the end of the line, it is trapped in a receiver. The gas is bled off from behind the pig.

As the pig travels through the pipeline, residual vapors are pushed through the line. If the vapors are not routed to a control device, typically a flare or incinerator, they escape through openings on devices such as hatches, doors, or vents. Emissions can be significant, depending on the amount and vapor pressure of the product. Depending on the gas used to push the pig, the bleed-off step can also emit significant amounts of VOC. Pigging vapors are commonly vented to a control device.[38] The Application and Application Review do not disclose these emissions or identify any control method.

C. Tank Flashing Emissions Omitted

Many of the cost-advantaged light crudes that the Terminal could import are transported raw, without stabilization, due to the lack of facilities in the oil fields. These unstabilized or "live" crude oils have high concentrations of volatile materials entrained in the bulk crude oil. Tank flashing emissions occur when these crude oils are exposed to temperature increases or pressure drops. When this occurs, some of the compounds that are liquids at the initial pressure/temperature transform into gases and are released or "flashed" from the liquid. These emissions are in addition to working and breathing emissions from tanks and are not estimated by the EPA TANKS 4.0.9d model. These emissions can be calculated using standard procedures.[39] The VOC potential to emit calculations did not mention or calculate these emissions, nor do the tank permits include a permit condition that allows only stabilized crude oils to be received.

D. Water Draw Tank Emissions Omitted

Crude oil typically contains small amounts of water, which is separated from the crude oil and accumulates in the bottom of storage tanks. This accumulated water, referred to as tank water draw, is typically transferred from the crude oil storage tanks into a smaller water draw surge tank for processing prior to disposal. Over time, a thick layer of crude oil forms in the

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[38] Eastern Research Group, Inc., Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations, September 1999, Available at: http://www.epa.gov/ttnchie1/eiip/techreport/volume02/ii10.pdf.

[39] See, *e.g.*, calculation methods at: Paul Peacock, Marathon, Bakken Oil Storage Tank Emission Models, March 23, 2010, Available at: www.ndoil.org/image/cache/peacock_-_march_23_2010._ppt.pdf; TCEQ, Air Permit Reference Guide APDG 5941, Available at: http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/guidance_flashemission.pdf; Kansas Dept. of Health & Environment, Available at: http://www.kdheks.gov/bar/download/Calculation_Flashing_Losses_Handout.pdf; B. Gidney and S. Pena, Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation, July 16, 2009, Available at: http://www.bdlaw.com/assets/htmldocuments/TCEQ%20Final%20Report%20Oil%20Gas%20Storage%20Tank%20Project.pdf .

water draw surge tank.[40] The water draw surge tank and processing of wastewaters from it emit VOCs. The tanks may be closed and vented to a control device. The Application Review does not mention water draw, or include emissions from storing or processing it. The oily water from the tank water draw would likely be collected in a sump and processed in the oily water sewer system, separately permitted in 2014 (Comment f), thus linking this separate permit action to the Terminal permits.

E. Pump Pit Emissions Were Omitted

The Terminal as originally proposed in 2012 was designed to include 15 pump pits, each with pumps designed to be connected to four railcars each. The pump pits are remote from the unloading rack and were preliminarily designed to be about 20 ft by 20 ft by 5 ft deep.[41] Pump leaks would collect in these pits and evaporate, emitting VOCs. These VOC emissions were not included in the potential to emit calculations. Further, the collection system to recover and treat collected leaks was permitted as a separate project in September 2014. The oily water from these pump pits would likely be processed in the oily water sewer system, separately permitted in September 2014 (Comment f), thus linking this separate permit action to the Terminal permits.

F. Sump Tanks and API Separator Emissions Were Omitted

In September 2014, the new owner, Plains, applied for an Authority to Construct for a drain tank system and an oil/water separator at the Terminal.[42] The equipment covered by this application is the oily water sewer system for the Terminal and should have been included in the original 2012 Application. As noted by Argonne National Laboratory, "[a]ll pipeline terminals need to handle the drainage of lubricants and pipeline products, sampling dump stations, contaminated condensates, etc."[43]

This 2014 modification included four 24-barrel sump tanks and a 20,000-gallon oil/water separator, each separately controlled by a 200-lb carbon canister. The emissions from this new equipment were erroneously omitted from the VOC potential to emit calculation. The September 2014 Application explains that the sump tanks would be used as lift stations, to collect equipment drains and equipment pad surface drainage in the offloading metering, pump stations, pipeline booster pump, and pig launcher areas. The oil/water separator would treat water from

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[40] See, for example, TRW Environmental Operations, Emission Test Report, Petroleum Refinery Wastewater Treatment System, Chevron U.S.A., Inc., El Segundo, California, March 1984, EMB Report 83-WWS-2, March 1984, pdf 68 and Fig. 3-1, Available at: http://nepis.epa.gov/Exe/ZyPDF.cgi/9100EN7A.PDF?Dockey=9100EN7A.PDF; Linda M. Curran, Waste Minimization Practices in the Petroleum Refining Industry, 1992, Available at: http://infohouse.p2ric.org/ref/39/38867.pdf and Kimman Process Solutions B.V., Automatic Tank Dewatering, Available at: http://www.kpsnl.com/en/applications-en/miscellaneous-refineries-en/tank-dewatering-en.

[41] E-mail from Michael C. Ernst to Joe Henderson, RPMS Engineers, Re: Follow-up on Tank Question for Crude Oil Terminal, June 25, 2012 2:28 PM.

[42] Letter from Glen Mears, Plains LPG Services, L.P., to Leonard Scandura, SJVAPCD, Re: Authority to Construct Application, Bakersfield Crude Terminal, LLC, September 8, 2014 ("September 2014 Application").

[43] T.C. Pharris and R.L. Kolpa, Overview of the Design, Construction, and Operation of Interstate Liquid Petroleum Pipelines, Argonne National Laboratory Report ANL/EVS/TM/08-1, November 2007, p. 5, Available at: http://corridoreis.anl.gov/documents/docs/technical/APT_60928_EVS_TM_08_1.pdf.

the oily water sewer by separating the oil from the water and routing VOC-laden vapors to carbon canisters. Separated oil would be removed by vacuum truck.

The District estimated VOC emissions from this equipment as 100 lb/yr for each of the sump tanks and 109 lb/yr for the oil/water separator, for a total of 509 lb/yr.[44] These emissions plus those from the Terminal, as permitted in 2012, add up to 20,501 lb/yr, which exceeds the major source threshold.

However, rather than concluding that the Terminal is a major source, the District cites its Policy APR 1130 and asserts that new units with emissions of 0.54 lb/day or less are not included in major source determination calculations. As each proposed unit (the four tanks and the oil/water separator) has emissions of less than 0.54 lb/day, according to the District, the facility will remain a minor source.[45] However, the District has misapplied its policy.

This policy only applies to "increases in permitted emissions." The subject equipment should have been permitted in 2012 with the rest of the Terminal as the equipment is required for the Terminal to operate. This type of equipment is used at all crude oil terminals and should have been anticipated and included in the original 2012 Terminal Application. Sump tanks, for example, are used at crude loading terminals to: (1) collect any material, such as drips from equipment such as pumps that might be released during a malfunction or process upset; (2) to collect material from spill cleanups; (3) to collect tank water draws; and (4) to collect crude oil from pigging operations and maintenance activities. An oil/water separator is required to treat the oily water before it is discharged into the environment, e.g., receiving waters or a septic/leach field. Thus, the subject emissions should not be treated as "increases in permitted emissions," but rather should have been included in the emissions to make the original major source determination. The project has been piecemealed by separately permitting components required for the Terminal to operate.

Further, this policy circumvents federal law, which requires that all sources of emissions be included in potential to emit calculations, regardless of their magnitude. This policy was not adopted in EPA's approval of the District's NSR rule and cannot be used to make a federal minor source claim.

G. Cargo Carrier Emissions

The Terminal at buildout would receive and offload up to two unit trains per day of 104 rail cars each and is expected to operate 14 hours per day. District Rule 2201, Section 4.7, requires that emissions from cargo carriers while present on site be included in the potential to emit. Section 3.12 defines cargo carriers as "trains dedicated to a specific Stationary Source…." The District's Application Review for the similar Alon Terminal (2 unit trains per day designed to simultaneously unload 150,000 bbl/day of crude oil into new tanks) concluded that on-site emissions from the locomotives meet the definition of "cargo carriers" as "..once the trains arrive at Alon, the applicant and the District agree that the trains are under the complete control of Alon

[44] SJVAPCD, Authority to Construction Application Review, September 20, 2014 ("Tank/Separator Application Review").
[45] September 2014 Application Review, p. 5.

management, are dedicated to the refinery, and are in fact "Cargo Carriers" subject to Rule 2201. Specifically, the resulting onsite emissions from these Cargo Carrier operations are subject to the requirements of Rule 2201."[46]

The District included 1.0 lb/day and 380 lb/yr of VOC emissions from cargo carriers in its potential to emit for the Alon Facility.[47] The cargo carrier emissions from the Bakersfield Crude Terminal would be larger, as it will unload 168,000 bbl/day, compared to 150,000 bbl/day at Alon. Thus, cargo carrier emissions from Bakersfield Crude Terminal would about 1.12 times greater than from the Alon Terminal or about 426 lb/yr. Cargo carrier emissions, when added to the District's 2012 potential to emit of 19,992 lb/yr, results in VOC emissions of 20,418 lb/yr,[48] exceeding the major source threshold and classifying the Bakersfield Crude Terminal as a major source under Rule 2201.

H. Stationary Combustion Sources

A facility that handles flammable material, such as crude oil, is required by the fire code to have a fire pump and diesel generator. To assure that these are in good operating condition when needed, they are periodically tested. These are typically fossil-fuel fired and thus generate emissions, including VOCs, when tested. These emissions were not included in the potential to emit.

On October 16, 2014, Plains Marketing, L.P. applied to the Air District to construct two emergency fire water pumps fired by diesel engines.[49] In the Air District's Authority to Construct Application Review, each pump was projected to emit 2 lbs of VOCs per year, or 4 pounds per year total.[50] This permit should have been included with the initial 2012 permitting action. The project has been piecemealed by separately permitting components required for the Terminal to operate.

[46] SJVAPCD, Authority to Construct Application Review, Alon USA – Bakersfield Refinery, October 14, 2014 ("Alon Application Review"), p. 7.
[47] Alon Application Review, p. 26.
[48] Bakersfield Crude Terminal cargo carrier emissions, estimated from Alon Terminal cargo carrier emissions = (380 lb/yr)(168/150) = 426 lb/yr. The revised PTE = 19,992 + 426 = **20,418 lb/yr.**
[49] Letter from Glen Mears, Plains Marketing, L.P., to Leonard Scandura, SJVAPCD, Re: Authority to Construct Application, Bakersfield Crude Terminal, LLC, October 16, 2014.
[50] SJVAPCD, Authority to Construct Application Review, Fire Pumps, November 13, 2014.

III. Permit Conditions Are Not Enforceable

The emissions from the Terminal, when operated at its maximum capacity based on its physical and operational design, would emit more than 20,000 lb/yr of VOCs and thus should be a major source. Operational limitations were imposed in the ATC permits to attempt to reduce VOC emissions to 19,992 lb/day, just 8 lb/yr shy of the major source threshold. Operational limitations, such as those imposed here, can only be relied on to limit the potential to emit if they are incorporated into the permit as enforceable conditions.[51] Most of these operational limitations are not enforceable. Further, the permits require no reporting, precluding District and citizen enforcement.

A. Tank Permit Conditions Are Not Enforceable

The total Terminal VOC emissions were calculated in the District's 7/25/12 Application Review as the sum of emissions from two tanks (2 x 9,460 = 18,920 lb/yr), fugitive components (617 lb/yr), and disconnect losses (455 lb/yr).[52] The tank permits (S-8165-1 and -2) limit the emissions from both tanks combined to 18,920 lb/yr.[53] These limits are not enforceable because the permits do not require adequate monitoring, fail to specify how VOC emissions would be calculated, and do not require any reporting.

VOC emissions from tanks are generally not measured but rather are calculated using the EPA computer model, TANKS 4.0.9d. The key input parameter that determines tank VOC emissions is the Reid Vapor Pressure (RVP) of the material stored in the tank. The RVP is a measure of the volatility of the material. The higher the volatility (and RVP), the higher the VOC emissions. The tank emission limit of 18,920 lb/yr was estimated in the Application Review with the TANKS model, assuming a RVP of 8.3 psia, which yielded 9,460 lb/yr for each tank.[54]

However, the tank permits allow materials to be stored in the tanks with an RVP of up to 11.0 psia.[55] This vapor pressure limit would allow VOC emissions from each tank of 13,961 lb/yr.[56] Under this limit, VOC emissions from both tanks would be 27,922 lb/yr, which exceeds the major source threshold of 20,000 lb/yr, without including emissions from fugitive components, disconnects, and various omitted sources discussed elsewhere. Thus, VOC emissions from the tanks alone would qualify the Terminal as a major source, unless the permits contain operational or other limits that would restrict the potential to emit VOCs to less than 20,000 lb/yr. This could be done by placing enforceable limits on emissions from the tank, which are the major source of emissions from the Terminal.

The tank permits attempt to address this issue in Condition 7, which requires: "If any shipment of organic liquid with an RVP greater than 8.3 psia is introduced, placed, or stored in this tank in any calendar year, compliance with annual combined emission limit for tanks listed

[51] District Rule 2201, Sec. 3.27.
[52] 7/25/12 Application Review, pp. 4-5.
[53] ATC Permits S-8165-1-0 and 8165-2-0, Condition 5.
[54] 7/25/12 Application Review, pp. 4-5 and Appx. E, 6/27/12 TANKS run for RVP = 8.3 psia.
[55] ATC Permits S-8165-1-0 and 8165-2-0, Condition 6.
[56] 7/25/12 Application Review, Appx. E, 7/17/2012 TANKS Run for RVP=11 psia (p. 2 of 5).

on S-8165-1 and '-2 [the tank permits] shall be demonstrated by calculating and maintaining an annual emission summary using the EPA's TANKS program." This condition renders the tank emission limit of 18,920 lb/yr unenforceable as a practical matter for two reasons.

1. *Vapor Pressure (RVP)*

The volatility of a crude oil is measured in pounds per square inch absolute (psia) and is typically reported as Reid Vapor Pressure (RVP) at 100°F.[57] Vapor pressure is an indirect measure of the evaporation rate of volatile compounds in the crude oil such as VOCs, with higher vapor pressures indicating greater losses of VOCs from evaporation. There is a well established relationship between the vapor pressure of a crude oil and the amount of VOC emissions released from equipment containing the crude oil.[58] This relationship is incorporated into the EPA TANKS 4.0.9d model, universally used to estimate VOC emissions from tanks, including in the subject permits.

The crude oil RVP is the key input into the TANKS program used to calculate VOC emissions. However, the tank permits do not require that the RVP of materials stored in the tanks be measured. The permits do not disclose how (method), where (field, shipping point, unit train), or by whom (supplier, shipper, applicant) the RVP will be determined. This is a major omission as tank VOC emissions cannot be estimated without the RVP of the "stored" material.

E-mail correspondence between the applicant and District suggest that "supplier published oil assays" would be used.[59] The applicant proposed the use of "oil assays" and stated: "We would be able to assign a RVP value to each shipment based on assay data for its place of origin."[60] Tanks Condition 7 refers to the RVP of "any shipment", suggesting that "shipment" RVP would be used. Shipment vapor pressure is not adequate to control VOC emissions from the tanks.

However, the permits themselves do not require *any* vapor pressure measurements, not even shipment or supplier assays or any other source, leaving this critical metric essential to calculate VOC emissions to the discretion of the applicant to specify. The applicant, for example, could simply estimate the RVP, based on a shipment's point of origin as suggested in e-mails, or some other arbitrary criterion, such as marketing assays, picked to assure emissions remain below the major source threshold. Thus, the VOC emission limit in Condition 5 of both tank permits is unenforceable.

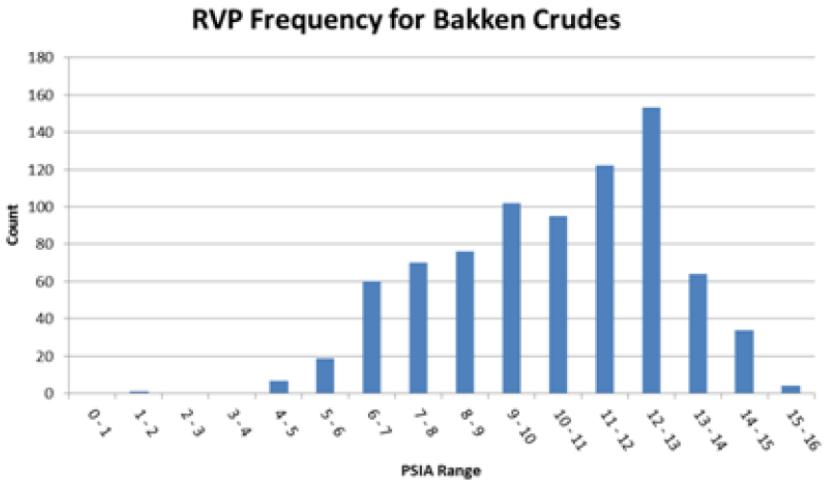
If shipment or supplier assays were used, VOC emissions would likely be incorrectly estimated, as the RVP of crude oils is known to vary substantially from field to field, from well

[57] Measured by American Society for Testing and Materials Method ASTM D323-08, Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method) is used to determine the vapor pressure at 100 F with initial boiling point above 32 F.
[58] See AP-42, Section 7.1: Organic Liquid Storage Tanks.
[59] E-mail from Michael C. Ernst, HDR Inc., to Kristopher Rickards, SJVAPCD, Re: Bakersfield Crude Terminal, LLC, July 17, 2012 12:33 PM ("I just want to be clear we would be getting the RVP from the suppliers published oil assays, not sampling and analyzing each train.")
[60] E-mail from Michael C. Ernst, HDR Inc., to Kristopher Rickards, SJVAPCD, Re: Bakersfield Crude Terminal, LLC, July 17, 2012 8:22 AM.

to well within a field, and from time to time within the same well.[61] Further, a unit train may include tanks cars carrying crude oil from several different sources. The tank permits, as written, give the applicant the flexibility to pick a vapor pressure that assures VOC emissions remain below the VOC emission limit.

The characteristics of one of the crude oils that likely would be handled at the Terminal, Bakken crudes, was surveyed by the American Fuel & Petrochemical Manufacturers (AFPM) of it members, at the request of the Department of Transportation. This survey revealed that these crudes have an RVP of up to 15.5 psi, far above the upper permitted limit of 11.0 psia. Vapor pressure data collected in this survey[62] and summarized in Figures 2 and 3 indicate that the vapor pressure of these crudes is highly variable. Bakken crude oil offered for transportation was found to have RVP values ranging from 0.8 to 15.54 psia, as summarized in Figure 2. Thus, a single published shipper assay would be worthless for determining compliance with the VOC limits in the subject tank permits.

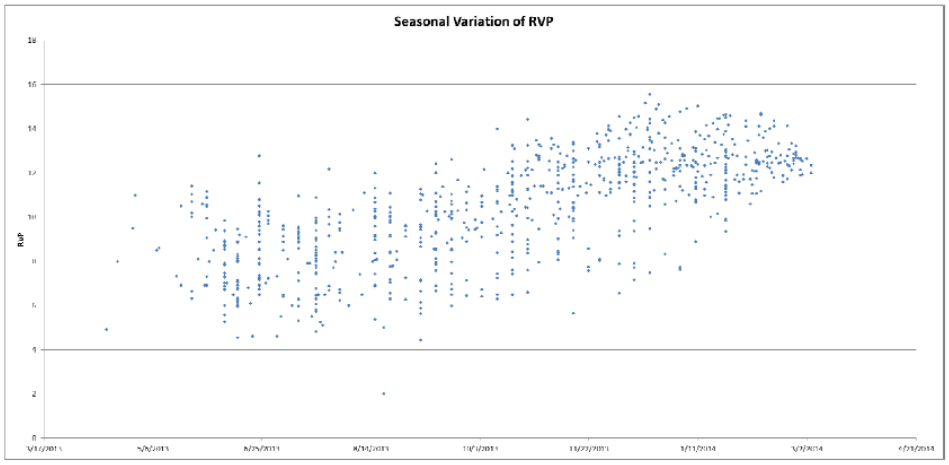
Figure 2.[63]



Other data collected in the AFPM survey show significant seasonal variation in RVP, ranging from 8 psia for warmer times of the year and an average 12.5 psia during colder periods. Figure 3. Thus, a single published shipper assay is worthless for determining compliance with the tank VOC limits.

[61] Department of Ecology, State of Washington, Washington State Draft 2014 Marine & Rail Oil Transportation Study, December 1, 2014, Publication No. 14-08-015, Table 78 [VPCR 4 @ 100°F (psia)], Available at: https://fortress.wa.gov/ecy/publications/publications/1408015.pdf.
[62] Dangerous Goods Transportation Consulting, Inc., A Survey of Bakken Crude Oil Characteristics Assembled for the U.S. Department of Transportation, Submitted by American Fuel & Petrochemical Manufacturers, May 14, 2014, Available at: https://www.afpm.org/WorkArea/DownloadAsset.aspx?id=4229.
[63] Dangerous Goods Transportation Consulting, Inc., May 14, 2014, p. 19.

Figure 3.
Seasonal Variation in RVP[64]



The AFPM survey further indicated that "[r]ecipients monitor crude oil for RVP to ensure compliance with these environmental regulations. One respondent noted that they test the RVP of every rail shipment at the time of loading and upon receipt." Due to increased potential for pump cavitation, other respondents noted "[a] limiting RVP of 10 psia was reported as typical for crude oils transported by pipeline where pumping is required."[65] However, the subject tank permits require no monitoring of RVP to determine compliance with VOC emission limits.

The tank permits limit VOC emissions from the tanks based on the vapor pressure of material stored in the tank. Tank permit Condition 6 limits the RVP of "liquid introduced, placed, or stored in the tank." Condition 35 further requires daily and annual records of throughput and annual tank emissions "if any liquid is introduced, placed, or stored in the tank that has an RVP greater than 8.3 psia." Thus, the permit is clear that the RVP limit applies to the tank, not the rail car, pipeline, shipper, or oil field. However, the permits do not require RVP to be measured or reported anywhere, rendering the tank VOC limits unenforceable.

A shipper published assay for a crude oil from a given field, or for a given shipment, does not satisfy this permit language. These shipper assays are typically average or typical assays for a field, not assays for materials "introduced, placed, or stored" in the Terminal tanks. Even if the shipper assay were based on a specific unit train, substantial variability could occur among the cars, as a unit train contains 104 rail cars, each containing about 30,000 gallons of oil. Each rail car could contain oil from a different source, with a different vapor pressure.

Further, only a portion of each unit train load, 2,940,000 gallons per day or 42% on average, is routed through the tanks.[66] The balance, 7,056,000 gallons per day, is sent directly to the pipeline. The pipeline portion would have to meet pipeline vapor pressure limits, which are

[64] Dangerous Goods Transportation Consulting, Inc., May 14, 2014, p. 20.
[65] Dangerous Goods Transportation Consulting, Inc., May 14, 2014, p. 20.
[66] E-mail from Michael C. Ernst, HDR Inc. to Ashley Dahlstrom, SJVAPCD, Re: Additional Information Required, June 1, 2012 12:15 PM.

in the range of 8.2 to 8.3 psia,[67] much lower than the tank vapor pressure limit of 11.0 psia. Thus, it is reasonable to expect that higher vapor pressure material would be routed to the tanks for blending.

Further, as only a portion of each load is stored in the tanks, and given the substantial demonstrated variability in crude oil vapor pressure, the vapor pressure must be measured at the tank itself. To assure compliance with daily limits, the vapor pressure must be measured every day. The tank permits do not require any vapor pressure measurements, anywhere, let alone at the emission point, the tanks themselves, on a daily basis.

Under these permits, the actual vapor pressure of the stored material in the tanks would never have to measured or be used to estimate tank emissions. Thus, the VOC emission limits in Condition 5 of the tank permits are not enforceable.

2. *VOC Emission Calculation*

Conditions 7 of the tank permits require that if any shipment with an RVP greater than 8.3 psia is "introduced, placed, or stored in this tank in any calendar year, compliance with annual combined emission limit for tanks listed on S-8165-1 and '-2 shall be demonstrated by calculating and maintaining an annual emission summary using the EPA's TANKS program." The combined limit is 18,920 lb-VOC/yr in Condition 5. This limit was calculated by the District using the TANKS program, run in the annual mode with an RVP of 8.3 psia and many other input assumptions. However, at the Terminal, the RVP varies from day to day. The District expressed concern, noting "the only issue we would have is how the actual averaging of vapor pressure would be calculated for the annual emissions."[68] The permits are silent on how this calculation should be made. Further, the tank permits do not limit any of the other TANKS input variables. Thus, Condition 7 cannot be used to enforce Condition 5.

First, the tanks combined VOC limit of 18,920 lb/yr was calculated using the TANKS model for a specific set of input values, including crude oil characteristics (RVP of 8.3 psia; molecular weight of 207) and tank characteristics, including tank dimensions, paint characteristics, rim-seal system, deck characteristics, and deck fitting/status. One simple change in these inputs, from a roof condition of "good" to "poor," for example, was sufficient to tip the VOC emissions over the major source threshold in the District's emission calculations.[69] The tank permits do not require that the roof be maintained in "good" condition, nor do they require that the tanks be built to meet the specifications assumed in the TANKS model run used to estimate the VOC emission limit. Thus, the combined tanks VOC limit of 18,920 lb/yr is not enforceable via calculation with the TANKS model as all of the inputs are not limited by permit conditions.

[67] E-mail from Michael C. Ernst, HDR Inc, to Kristopher Rickards, SJVAPCD, Re: Bakersfield Crude Terminal, LLC, July 11, 2012 12:37.
[68] E-mail from Kristopher Rickards, SJVAPCD, to Michael Ernst, HDR Inc., Re: Bakersfield Crude Terminal, LLC, July 16, 2012 3:21 PM.
[69] See E-mail from Michael Ernst, HDR Inc. to Kristopher Rickards, SJVAPCD, June 27, 2012.

Second, Condition 7 does not explain how the TANKS model would be used to demonstrate compliance. The TANKS model calculates annual or monthly VOC emissions for a single vapor pressure input and tank throughput (number of turnovers), but not for other time steps with varying vapor pressures and throughputs.[70] The dual vapor pressure limit, a maximum of 11.0 psia and an annual average of 8.3 psia, requires a non-standard use of the TANKS model that is not specified in the permit, granting the applicant discretion as to how compliance will be determined.

The TANKS model does not calculate annual average VOC emissions under varying flow and vapor pressure conditions, as required here to determine compliance with dual vapor pressure limits. This is a novel use of the TANKS model that has never been used in a District permit and that has not been demonstrated to yield reliable, enforceable results. The applicant and the District considered various approaches including: (1) use of daily throughputs to calculate a rolling average RVP to show the average RVP is less than 8.3 for any 12 months;[71] (2) use of volume-weighted average RVP; and (3) run the entire year's throughput for each tank through TANKS to show that the annual emissions are below permitted levels.[72] However, the permit is silent on the approach that must be used to demonstrate compliance.

The lack of a tested method to calculate compliance using the TANKS model is discussed in e-mail correspondence between the applicant and the District. The District advised as follows: "…for ongoing annual compliance I'm not sure this [an average RVP] would be feasible for the facility to do, and I would have to run this by our compliance department to see if that's something they could enforce as well. To my knowledge (and after searching permit condition language of District permits) using an average TVP [total vapor pressure] hasn't been written into any permits here, but if we could find a way to make it work we could go from there."[73] Thus, e-mail correspondence acknowledges that using the TANKS model to determine compliance with the vapor pressure limit is not straightforward and that there is no precedent for an annual average vapor pressure limit. However, the permit fails to specify a method.

The tank permits do not explain how the TANKS program would be used to determine compliance with the volume-weighted VOC limit in Condition 5. Conditions 5 and 7 are not enforceable without specifying a calculation method. An inspector, for example, could not determine on the spot whether the facility was in compliance, except at the end of each year when the annual average is calculated. Compliance could not be determined at all during the first year of operation. And the inspector would not know how to make the calculation.

The District permit engineer noted: "Keeping daily records of the throughput and RVP should allow us to verify compliance over any twelve month period. Let me know if this works

[70] U.S. EPA, User's Guide to Tanks, September 30, 1999, Section 5.0, Available at: http://www.epa.gov/ttn/chief/software/tanks/tank4man.pdf.
[71] E-mail from Michael C. Ernst, HDR Inc. to Kristopher Rickards, SJVAPCD, Re: Bakersfield Crude Terminal, LLC, July 17, 2012 12:33 PM.
[72] E-mail from Kristopher Rickards, SJVAPCD, to Michael Ernst, HDR Inc., Re: Bakersfield Crude Terminal, LLC, July 18, 2012, 16:14:20 GMT.
[73] E-mail from Kristopher Rickards, SJVAPCD, to Michael C. Ernst, HDR Inc., Re: Bakersfield Crude Terminal, LLC, July 17, 2012 17:28:30 GMT.

for you."[74] I agree. The most accurate method to calculate annual VOC emissions under varying throughput and RVP conditions would be to measure/record daily tank throughput and daily vapor pressure for each tank and run the TANKS model for each day. This would yield 365 estimates of daily emissions, which could be summed to yield annual VOC emissions. This approach is consistent with the use of the TANKS model to estimate VOC emissions when the tank stores different liquids during the year. The EPA recommends to "[e]stimate emissions for the time period over which each liquid was stored, and sum the emissions to obtain the annual emissions."[75]

The tank permits do not require that adequate data be collected to determine compliance with the annual VOC limit, regardless of how the VOC limit is expressed or calculated. Tank permits Condition 35 only require daily and annual "records" (not measurements) of tank throughput and annual emissions only if liquid with an RVP greater than 8.3 psia is introduced. However, to make the annual calculation required to determine compliance, daily measurements of RVP and throughput are required regardless of the RVP.

Throughput measurements and annual emissions are only required to be "maintained" (not measured) if vapor pressure is less than 8.3 psia. Thus, the throughput information required to adjust the TANK output does not have to be collected or recorded, leaving it to the discretion of the applicant as to how these throughputs and vapor pressures would be determined. Condition 35 should be modified to require daily and annual measurement and recording of tank vapor pressure and throughput, regardless of the vapor pressure. Finally, the tank permits should be modified to require that all of the data is reported to the District on a quarterly basis.

3. *Fixed Roof Tanks Are Required*

Condition 6 of the tank permits limits the RVP of liquid stored in the tanks to 11.0 psia. District Rule 4623 does not allow the use of floating roof tanks if the total vapor pressure (TVP) of the stored material is greater than or equal to 11.0 psia. Pressure vessels or fixed roof tanks vented to vapor recovery are required. Rule 4623, Sec. 5.1.1. The TVP corresponding to an RVP of 11.0 psia varies depending upon the temperature of the stored liquid. An RVP of 11.0 psia corresponds to a TVP of 11.0 psia at a temperature of about 78 F.[76] Higher temperatures, which are feasible on a hot summer day in Bakersfield, would exceed the TVP limit for floating roof tanks. For example, the District predicted the following tank surface temperature and corresponding TVPs for a crude oil RVP of 11.0 psia for a modification at the Terminal:[77]

- May: 82.17^{o}F, TVP =11.96 psia
- June: 86.51^{o}F, TVP = 12.75 psia
- July: 88.94^{o}F, TVP =13.20 psia
- August: 87.00^{o}F, TVP = 12.84 psia

[74] E-mail 7/17/12 Ernst to Ricards.
[75] TANKS Software Frequent Questions: "My tank stores different liquids during the year. How do I account for this variability?" Available at: http://www.epa.gov/ttn/chief/faq/tanksfaq.html#18.
[76] AP-42, Section 7.1, Organic Liquid Storage Tanks, Figure 7.1-13a, Available at: http://www.epa.gov/ttn/chief/ap42/ch07/final/c07s01.pdf.
[77] SJVAPCD, Authority to Construct Application Review, Fixed Roof Tanks, April 24, 2014, Appendix C, pdf 29.

- September: 82.28°F, TVP = 11.98 psia

The 2012 Application, Attachment B, asserts the maximum storage temperature will be 65 F. However, the tank permits do not limit the storage temperature of the tanks (or the material that can be stored) or require tank temperature measurements.

B. Unloading Rack Permit Conditions Are Not Enforceable

The District's potential to emit calculations for the unloading rack are based on two sources of VOC emissions: (1) disconnect losses (455 lb/yr) and (2) fugitive emissions (617 lb/yr). The unloading rack ATC permit (8165-3) does not limit either source of VOC emissions to the assumed levels.

1. *Disconnect Emissions*

The unloading rack is individually connected to each rail car with a 4-inch Todo-Matic drybreak connector by NovaFlex.[78] When the loading rack is attached and disconnected from the rail cars, some of the crude oil within the connector spills to the ground and evaporates, releasing VOCs.

The VOC emissions from hooking up each rail car with the loading rack and disconnecting it were calculated from the number of railcars per day (208), the average volume of spilled oil per disconnect (3.2 mL), and the density of the crude oil (7.1 lb/gal).[79] This resulted in 1.2 lb/day and 455 lb/yr of VOCs.[80] To make these VOC emissions enforceable, and assure they remain below the major source threshold (20,000 lb/day) and the public notice threshold (100 lb/day), the unloading rack permit would have to limit each of these factors to the levels assumed in the Application Review calculations (208 disconnects/day, 3.2 mL/disconnect, 7.1 lb/gal) and require measurement and recording of each factor on a daily basis. The permit fails this test.

The unloading rack permit (S-8165-3) does not limit disconnect VOC emissions to either 1.2 lb/day or 455 lb/yr as assumed in the Application Review nor does it require that all three factors required to calculate disconnect VOC emissions are measured daily. These factors are: number of disconnects per day, volume of each disconnect, and density of spilled material.

There is no limit at all on VOC emissions, e.g., the permit does not contain a condition limiting disconnect VOC emissions to 1.2 lb/day and 455 lb/yr. Rather than limiting VOC emissions, the permit takes the approach of limiting inputs to the VOC calculation. However, the permit fails to specify how the VOC emissions should be calculated to demonstrate compliance. Even if the permit required compliance by calculation, and specified the calculation

[78] E-mail from Joe Jenderson, RPM Engineers to Michael C. Ernst, SJVAPCD, Re: Follow-up on Tank Question for Crude Oil Terminal, June 26, 2012 7:23 AM.
[79] 7/25/12 Application Review, p. 4.
[80] From 7/25/12 Application Review, p. 4: Annual disconnect VOC emissions = (208 disconnects/day)(365 day/yr)(3.2 mL/disconnect)(0.000264 gal/mL)(7.1 lb/gal) = 455 lb VOC/yr.

method, there would be no obligation to meet any specific emission level, as the permit contains no target, e.g., 1.2 lb/day and 455 lb/yr.

There are additional problems with the undisclosed calculated method hinted at in the unloading rack permit. This calculation method is assumed to be that used in the 7/25/12 Application Review. However, the unloading rack permit fails to limit all three calculation inputs and only requires monitoring for one of them.

First, Condition 5 limits spill volume to 3.2 milliliters per disconnect based on the use of drybreak couplers. This value was selected "to keep the potential facility emissions below 20,000 lb/years (results in 19,991 lb-VOC/year). This would work but would leave very little margin for compliance."[81]

However, the permit does not require the use of drybreak couplers, nor any testing of disconnects to determine if 3.2 milliliters per drop is a reasonable estimate or is achievable at all. Further, the unloading rack permit is silent on methods that would be used to measure the disconnect volume from "3 consecutive disconnects". Thus, Condition 5 is not enforceable. Daily spill volume could be simply determined by locating a collection sump beneath the connection points and periodically measuring the accumulated volume.

Second, the number of disconnects is limited to 208 per day and 75,920 per year in Condition 2 and recordkeeping for the number of disconnects is required in Condition 15. However, spills could occur when the unloading rack arm is connected to the rail car and again when it is disconnected. Thus, up to two spills are possible for each rail car, which would double disconnect VOC emissions, compared to the potential to emit calculations, exceeding the major source threshold. Total VOC emissions would increase from 19,992 lb/yr, just under the major source threshold, to 20,447 lb/yr, which is over the threshold if drops during connects were included. This would not be discovered as the permit does not require any monitoring of either the number or volume of connection spills.

Third, the unloading rack permit does not limit the density of the spilled material. The 7/24/12 Application Review assumed a default crude density of 7.1 lb/gal from AP-42, Table 7.1-2.[82] However, the permits do not limit either the density or type of crude oil that will be unloaded at the facility. There are many cost-advantaged crudes available for transport by rail that have higher densities than assumed in these calculations, such as Canadian tar sands DilBit crudes.[83] The current owner of the Terminal, Plains, has rail access to the Bakersfield area from Canada, North Dakota, the midcontinent, the Permian Basin, and the Eagle Ford Basin. Further, it has pipelines that can move crudes to refineries in both northern and southern California.[84] Thus, crudes with a wide range of densities (as well as vapor pressures) could be handled at the

[81] E-mail from Kristopher Rickards, SJVAPCD, to Michael C. Ernst, Re: Bakersfield Crude Terminal, LLC, June 27, 2012 4:08 PM.
[82] 7/25/12 Application Review, p. 3.
[83] See, for example, heavy sour unconventional (density: 7.71 – 7.75 lb/gal) and heavy sour synbits (density: 7.77 – 7.82 lb/gas), Available at: http://www.crudemonitor.ca/home.php.
[84] http://california.maps.arcgis.com/apps/OnePane/basicviewer/index.html?appid=928033ed043148598f7e511a95072b89.

Terminal. If a Canadian tar sands DilBit crude were handled at the facility, for example, disconnect VOC emissions would increase from 455 lb/yr to 493 lb/yr. This small change alone would be sufficient to increase the potential to emit from 19,992 lb/yr to 20,030 lb/yr.[85]

In sum, the unloading rack permit does not limit the VOC emissions from disconnect losses to 1.2 lb/day or 455 lb/yr due to inadequate monitoring and recordkeeping. The permit as written would allow a substantial increase in VOC emissions from disconnect losses above those assumed in the potential to emit calculations, enough to classify the Terminal as a major source under rule 2201.

2. *Fugitive Emissions*

The VOC emissions relied on by the District to conclude this is not a major source include 617 lb/yr of fugitive emissions. Fugitive emissions are equipment leaks. The Application Review estimated these VOC emissions assuming 350 valves, 19 pump seals, and 800 connectors "per tank".[86] All of the fugitive emissions were included in the unloading rack permit, even though some of them are associated with the tanks.

Condition 3 of the permit limits VOC emissions from these components to 1.7 lb/day and 617 lb/yr, consistent with the District's potential to emit calculations. These VOC emission limits are not enforceable and they fail to limit the potential to emit VOCs from fugitive components.

First, the unloading rack permit (S-8165-3) is for "organic liquid transfer operation with light crude oil railcar unloading rack and associated offloading, transfer and booster pumps." Many of the fugitive components are associated with the connecting pipelines and tanks. The e-mails in which fugitive emissions are calculated, for example, lump some of the components with the tanks. Thus, there is ambiguity as to which fugitive components are regulated under the unloading rack permit.

Second, Conditions 3 and 16 require that compliance is determined by counting the number of components of each type (valve, pump, connector) and multiplying by EPA emission factors. The fugitive emission potential to emit calculations were based on 350 valves, 19 pump seals and 800 connectors. However, as some of these components are associated with the tanks and pipelines, they may not all be counted for the unloading rack permit.

The permit does not place any limit on the number or type of components, even though the permit engineer stated: "The component counts will be on the permit though as they account for emissions and must be accounted for under New Source Review (recordkeeping of

[85] VOC emissions if crude with a density of 7.7 lb/gal were unloaded: 19,992 – 455 + (7.7/7.1)(455) = **20,030 lb/yr**.
[86] 7/25/12 Terminal Application Review, p. 5, Table: "Fugitive Emissions from Components", second column: "Number of Components per Tank".

components will be required)."[87] Other similar permits issued by the District require the Permittee to submit a count of all fugitive emission sources to the District.[88]

Thus, the potential exists to underestimate fugitive emissions by excluding some of the fugitive components.

Second, the permit does not require any reporting of either fugitive VOC emissions or component counts to the District, precluding the District and citizens from discovering violations and enforcing the permit. See, for example, Pentland Pump Station Permit to Operate, Condition 10: "The operator shall submit reports of any required monitoring at least every six months unless a different frequency is required by an applicable requirement."

Third, it appears that the District may have underestimated fugitive emissions. The 7/25/14 Application Review uses the "number of components per tank" to calculate VOC emissions of 617 lb/yr. However, if the component count column heading is correct, this calculation is only for a single tank. The emissions from both tanks would be double this amount or 1,234 lb/yr. Revised total potential to emit would be 20,609 lb/yr,[89] which exceeds the major source threshold.

Fourth, Condition 8 requires that components be maintained in a "leak-free condition." However, the permit does not require periodic monitoring of the components to assure they are "leak-free". Other permits issued by the District have been modified to require that components be inspected annually for gas and liquid leaks pursuant to District Rule 2520, Sec. 9.3.2 to assure they are enforceable.[90]

Finally, in the November 2014 Application Review for Emergency Firewater Pumps, the District alleges for the first time that fugitive emissions are not included in major source determination calculations as the facility is not one of the source categories specified in 40 CFR 51.165.[91] However, fugitive emissions must be included for "petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels." 40 CFR 51.165(a)(iv)(C)(22). The ATCs do not limit the capacity of the tanks that would be installed. Further, the pipeline system itself serves as storage as well as conveyance. Thus, the storage capacity exceeds 300,000 barrels, qualifying the Terminal as one of the listed sources in 40 CFR 51.165.In addition, fugitive emissions must be included under 40 CFR 51.165 for stationary sources regulated under EPA's New Source Performance Standards (NSPS), 40 CFR 51.165(a)(iv)(C)(27). The facility includes organic liquid storage tanks, for which EPA has issued NSPS standards in 40 CFR Park 60, Subpart Kb. Thus, fugitive emissions were properly

[87] E-mail from K. Rickards to Michael C. Ernst, RE: Follow-up on Tank Question for Crude Terminal, June 25, 2012 9:48 AM.

[88] SJVAPCD, Permit to Operate, Plains Pipeline LP, Pentland Pump Station, July 28, 2011, condition 45, Available at: http://www.valleyair.org/notices/Docs/2011/07-28-11%20%28S-1091242%29/Public%20Notice%20Package.pdf.

[89] Revised Terminal emissions = 2x617 + 2x9,460 + 455 = **20,609 lb/yr.**

[90] Notice of Preliminary Decision – Federally Mandated Operating Permit, District Facility # S-1337, June 22, 2012, pdf 43, Condition 16, Available at: http://www.valleyair.org/notices/Docs/2012/06-22-12%20%28S-1112449%29/Public%20Notice%20Pkg.pdf.

[91] November 2014 Application Review, p. 5, footnote to table: "Rule 2201 Major Source Determination."

included by the Air District when calculating Terminal emissions in the 2012 Application Review.

3. *Other Unloading Emissions*

Finally, Condition 6 of the unloading rack permit (S-8165-3) sets a VOC emission limit for "transfer operations" of 0.08 pounds per 1000 gallons transferred. This is the ONLY condition limiting total VOC emissions from the unloading rack. Emissions from this rack may include other emission sources, not otherwise included in potential to emit calculations, such as emissions from open rail car hatches, rail car fitting leaks, pump sump emissions, etc.

E-mail correspondence indicates that the total Terminal throughput is 7,056,000 gallons per day.[92] Thus, this condition would allow 0.08 lb/1000 gal x 7,056,000 gal/day = 564.5 lb/day of VOC emissions or 206,035 lb/yr. Therefore, this condition does not limit the potential to emit VOCs to the level assumed in the Application Review to classify the Terminal as a minor source. This limit would allow the Terminal to exceed both the public notice limit of 100 lb/day and the major source limit of 20,000 lb/yr. While it is a generic limit applied to transfer of organic liquids under District Rule 4624, in this case, it would allow the major source threshold to be exceeded as the permit contains no enforceable limits to otherwise control total Terminal VOC emissions.

This limit is not enforceable, as the permit does not limit the amount of organic liquid that can be transferred and it does not require any testing to determine compliance, as specifically required by Rule 4624, Sec. 6.2.1.3.2 A.

4. *Loading Into Tanker Trucks*

The rail cars could be unloaded directly into tanker trucks, rather than the tanks or pipeline and shipped to market, bypassing both the tanks and pipeline. This is currently being practiced at several rail terminals in California, including the Kinder Morgan Terminal in Richmond, the Interstate Terminal in Sacramento, and the Paloma Terminal in Bakersfield. This would increase VOC emissions above those included in the VOC limits in the permits. Thus, to assure emissions remain below the VOC emission limits, which are calculated, rather than measured, the permits should be conditioned to prohibit loading into tanker trucks.

IV. Reporting Requirements Are Not Adequate To Assure Compliance

The permits do not require any reporting of collected data to the District, except Condition 33 in permits S-8165-1 and -2, which requires reporting of floating roof tank inspections. Thus, there is no way for either the District or citizens to determine if the Terminal

[92] E-mail from Michael C. Ernst, HDR Inc. to Ashley Dahlstrom, SJVAPCD, Re: Additional Information Required, June 1, 2012 12:15 PM.

is in compliance. Permits for similar facilities typically require periodic reporting of conditions set to limit emissions, as well as prompt reporting of deviations.[93]

[93] *See, e.g.*, South Coast Air Quality Management District Annual Emission Reporting Program, available at http://www.aqmd.gov/home/regulations/compliance/annual-emission-reporting; SJVAPCD, Permit to Operate, Plains Pipeline LP, Pentland Pump Station, July 28, 2011, Available at: http://www.valleyair.org/notices/Docs/2011/07-28-11%20%28S-1091242%29/Public%20Notice%20Package.pdf.