John R. Kasich, Governor
Mary Taylor, Lt. Governor
Scott J. Nally, Director

12/23/2013

Certified Mail

No	TOXIC REVIEW
Yes	PSD
No	SYNTHETIC MINOR TO AVOID MAJOR NSR
Yes	CEMS
Yes	MACT/GACT
Yes	NSPS
Yes	NESHAPS
Yes	NETTING
No	MAJOR NON-ATTAINMENT
Yes	MODELING SUBMITTED
Yes	MAJOR GHG
No	SYNTHETIC MINOR TO AVOID MAJOR GHG

Paul Logsdon
Lima Refining Company
1150 South Metcalf Street
Lima, OH 45804

RE: FINALAIR POLLUTION PERMIT-TO-INSTALL
Facility ID: 0302020012
Permit Number: P0114527
Permit Type: Initial Installation
County: Allen

Dear Permit Holder:

Enclosed please find a final Ohio Environmental Protection Agency (EPA)Air Pollution Permit-to-Install (PTI) which will allow you to install or modify the described emissions unit(s) in a manner indicated in the permit. Because this permit contains several conditions and restrictions, we urge you to read it carefully. Because this permit contains conditions and restrictions, please read it very carefully. In this letter you will find the information on the following topics:

- **How to appeal this permit**
- **How to save money, reduce pollution and reduce energy consumption**
- **How to give us feedback on your permitting experience**
- **How to get an electronic copy of your permit**

How to appeal this permit

The issuance of this PTI is a final action of the Director and may be appealed to the Environmental Review Appeals Commission pursuant to Section 3745.04 of the Ohio Revised Code. The appeal must be in writing and set forth the action complained of and the grounds upon which the appeal is based. The appeal must be filed with the Commission within thirty (30) days after notice of the Director's action. The appeal must be accompanied by a filing fee of $70.00, made payable to “Ohio Treasurer Josh Mandel," which the Commission, in its discretion, may reduce if by affidavit you demonstrate that payment of the full amount of the fee would cause extreme hardship. Notice of the filing of the appeal shall be filed with the Director within three (3) days of filing with the Commission. Ohio EPA requests that a copy of the appeal be served upon the Ohio Attorney General’s Office, Environmental Enforcement Section. An appeal may be filed with the Environmental Review Appeals Commission at the following address:

Environmental Review Appeals Commission
77 South High Street, 17th Floor
Columbus, OH 43215

How to save money, reduce pollution and reduce energy consumption

The Ohio EPA is encouraging companies to investigate pollution prevention and energy conservation. Not only will this reduce pollution and energy consumption, but it can also save you money. If you would like to learn ways you can save money while protecting the environment, please contact our Office of Compliance Assistance and Pollution Prevention at (614) 644-3469. Additionally, all or a portion of the capital expenditures related to installing air pollution control equipment under this permit may be eligible for financing and State tax exemptions through the Ohio Air Quality Development Authority (OAQDA) under Ohio Revised Code Section 3706. For more information, see the OAQDA website: www.ohioairquality.org/clean_air

How to give us feedback on your permitting experience

Please complete a survey at www.epa.ohio.gov/survey.aspx and give us feedback on your permitting experience. We value your opinion.

How to get an electronic copy of your permit

This permit can be accessed electronically via the eBusiness Center: Air Services in Microsoft Word format or in Adobe PDF on the Division of Air Pollution Control (DAPC) Web page, www.epa.ohio.gov/dapc by clicking the "Search for Permits" link under the Permitting topic on the Programs tab.

If you have any questions, please contact Ohio EPA DAPC, Northwest District Office at (419)352-8461 or the Office of Compliance Assistance and Pollution Prevention at (614) 644-3469.

Sincerely,

Michael W. Ahern

Michael W. Ahern, Manager
Permit Issuance and Data Management Section, DAPC

Cc: U.S. EPA
Ohio EPA-NWDO; Indiana

Response to Comments

Facility ID:	0302020012
Facility Name:	Lima Refining Company
Facility Description:	Petroleum Refinery and Storage
Facility Address:	1150 South Metcalf Street Lima, OH 45804 Allen County
Permit:	P0114527, Permit-To-Install - Initial Installation
A public notice for the draft permit issuance was published in the Ohio EPA Weekly Review and appeared in the The Lima News on 8/27/2013. The comment period ended on 10/07/2013.	
Hearing date (if held)	**10/1/13**
Hearing Public Notice Date (if different from draft public notice)	

The following comments were received during the comment period specified. Ohio EPA reviewed and considered all comments received during the public comment period. By law, Ohio EPA has authority to consider specific issues related to protection of the environment and public health. Often, public concerns fall outside the scope of that authority. For example, concerns about zoning issues are addressed at the local level. Ohio EPA may respond to those concerns in this document by identifying another government agency with more direct authority over the issue.

In an effort to help you review this document, the questions are grouped by topic and organized in a consistent format. PDF copies of the original comments in the format submitted are available upon request.

1. Topic: The permit applicant, Lima Refining Company, submitted a total of 76 written comments, with suggested language changes and rule clarifications.

Comment #1: typographical error in Table 1 of the Staff Determination document for emissions unit P050 listed NOx increase as 0.01 tpy, but should be 0.10 tpy. Total NOx in this table is correct.

Response #1: Ohio EPA concurs with the applicant. However, since the total NOx in this table is correct, and NOx was already triggered for Prevention of Significant Deterioration review, the error does not affect the calculations.

Comment #2: Page 12, term B.2 and B.3 – emissions unit P040 (existing SRU) is currently subject to NSPS Subpart J because of specific language in Federal Consent Decree Addendum, civil action No. SA07CA0683RF. The unit is also subject to the newer NSPS Subpart Ja due to it being modified. The unit is therefore subject to both J and Ja.

Response #2: Ohio EPA concurs with the applicant, and revised the applicability for NSPS, Subpart J and Ja to include P040.

Comment #3: Page 12, term B.5 – there is a typographical error in 2nd paragraph, should read "VVa", not VV

Response #3: Ohio EPA concurs with the applicant, and corrected the typographical error.

Comment #4: Page 13, term B.7 – NSPS Subpart GGGa will not apply to emissions unit P005 because the changes do not meet the definition of "modification". The small number of new components added to the Coker is not enough to trigger NSPS Subpart GGGa.

Response #4: Ohio EPA concurs with the applicant, and deleted P005 from this term.

Comment #5: Page 13, term B.7 - there is a typographical error in 2nd paragraph, should read "GGGa", not "GGG".

Response #5: Ohio EPA concurs with the applicant, and corrected the typographical error.

Comment #6: Page 14, term B.10 – MACT Subpart CC applies to the rich amine flash drum that is part of the SRU 1 & 2 (P040) and the new SRU 3 (P049). Please add clarifying language to state that these conditions only apply to the rich amine flash drum vent.

Response #6: Ohio EPA concurs with the applicant, and added "rich amine flash drum vents" to the term.

Comment #7: Page 14, term B.11 – Refinery MACT II Subpart UUU does not apply to the new acid gas flare (emissions unit P050). MACT Subpart UUU applies to the new SRU (Claus 3), but this rule does not specify any situations where a flare is to be used as a control device for an SRU. The flare can serve as a point of emergency release of acid gas during an SRU upset – but this is not regulated by MACT Subpart UUU. The BAT and BACT language which was cited and cover NSPS 60.18 requires the same performance and monitoring standards for flares, thus removing the reference for UUU does not result in a practical change in its performance or monitoring requirements.

Response #7: Ohio EPA concurs with the applicant, and deleted P050 from this term.

Comment #8: Page 18, term C.1.b)(1)d., emissions unit B001 – change language "large gaseous fuel" to "in the unit designed to fire Gas 1 fuel" consistent with the final (current) Boiler MACT rule source categories.

Response #8: Ohio EPA concurs with the applicant, and revised the language accordingly.

Comment #9: Pages 18 and 19, term C.1.b)(1)g. and 1.b)(1)k., emissions unit B001 – the NOx limits for this heater (B001) should be based on BAT, not BACT, because the reconstruction of this heater does not increase the emissions of NOx above baseline levels. Thus, move all the NOx emissions limits (0.03 lb/million Btu of actual heat input, based upon a 365-day rolling average; 0.04 lb/million Btu of actual heat input based upon a 30-day rolling average; and 13.44 tons/rolling, 12-month period) to b)(1)g. under OAC rule 3745-31-05(D).

Response #9 Ohio EPA concurs with the applicant, and moved all NOx emissions limits to b)(1)g.

Comment #10: Pages 21 and 22, term C.1.b)(2)g. and 1.b)(2)l., emissions unit B001 – consistent with comment #9, delete the BACT requirements for NOx in 1.b)(2)l. and move two emissions limits (0.03 lb/million Btu of actual heat input, based upon a 365-day rolling average; and 13.44 tons/rolling, 12-month period) to b)(2)g.iii.

Response #10: Ohio EPA concurs with the applicant, and moved the two NOx emissions limits to b)(2)g.iii.

Comment #11: Page 21, term C.1.b)(2)h. and 1.b)(2)I., emissions unit B001 - consistent with comment #9,delete NOx from 1.b)(2)h. and add NOx to 1.b)2)i.

Response #11: Ohio EPA concurs with the applicant, and deleted NOx from 1.b)(2)h. and added NOx to 1.b)2)i..

Comment #12: Page 22, term C.1.c)(2) and 1.c)(3), emissions unit B001 – the Boiler MACT rule provides different tune-up frequencies for different types of circumstances. Additional language from 40 CFR 63.7540 should be added to account for other possible cases, with a 5-year frequency instead of annually if the process heater is defined as limited-use or has continuous oxygen trim systems.

Response #12: Ohio EPA concurs with the applicant, and added the 5-year inspection frequency as requested.

Comment #13: Page 23, term C.1.d)(2), emissions unit B001 - there is a typographical error, the paragraph under d)(2)b. should be a new permit condition d)(3) which makes all of the paragraphs after that advance one number.

Response #13: Ohio EPA concurs with the applicant, and advanced each paragraph one number.

Comment #14: Page 25, term C.1.d)(7)(d), emissions unit B001 – add language to heater design documents…"demonstrating the use of heat recovery and O2 monitoring"

Response #14: Ohio EPA concurs with the applicant, and added the language.

Comment #15: Page 30, term C.1.f)(1)h., emissions unit B001 – the draft compliance demonstration language for the SO2 emissions limit of 11.09 tons SO2 per 12-month rolling period, does not include reference to the non-H2S sulfur concentration used in the application to estimate the SO2 emissions limit. Since the limit was calculated using both H2S and non-H2S values, the compliance demonstration language should also use both. Revise the first sentence to: "Compliance shall be based upon the fuel flow and H2S monitoring and record keeping requirements specified in sections d)(2) through d)(5) plus a 50 ppmv allowance for non-H2S sulfur based on EPA published refinery test data, or more recent test value if future testing is performed."

Response #15: Ohio EPA concurs with the applicant, and revised the language accordingly.

Comment #16: Page 31, term C.1.f)(1)l., emissions unit B001 – there is a typographical error, "GHG MMR rule" should read "GHG MRR rule".

Response #16: Ohio EPA concurs with the applicant, and corrected the typographical error.

Comment #17: Page 33, term C.2, emissions unit B004 – Operations, Property and/or Equipment Description, this heater is not only being rebuilt, it is also being enlarged, thus add, "and modification" to the description.

Response #17: Ohio EPA concurs with the applicant, and added "and modification" to the description.

Comment #18: Page 33, term C.2.b)(1)d., emissions unit B004 – same as Comment #8, change language "large gaseous fuel" to "in the unit designed to fire Gas 1 fuel" consistent with the final (current) Boiler MACT rule source categories.

Response #18: Ohio EPA concurs with the applicant, and revised the language accordingly.

Comment #19: Pages 37 and 38, term C.2.c)(2) and 2.c)(3), emissions unit B004 – same as Comment #12, the Boiler MACT rule provides different tune-up frequencies for different types of circumstances. Additional language from 40 CFR 63.7540 should be added to account for other possible cases, with a 5-year frequency instead of annually if the process heater is defined as limited-use or has continuous oxygen trim systems.

Response #19: Ohio EPA concurs with the applicant, and added the 5-year inspection frequency as requested.

Comment #20 Page 39, term C.2.d)(6), emissions unit B004 – Please delete the date "…by December 31, 2013…" from this condition. This requirement of the Consent Decree will not apply to this existing heater until it is modified (which will be later than the date listed here). Consequently, the new NOx CEMs will be installed once the heater has been reconstructed.

Response #20 Ohio EPA concurs with the applicant, and deleted the date.

Comment #21 Page 41, term C.2.d)(9), emissions unit B004 – similar to Comment #20,Please delete the date "…by December 31, 2013…" from this condition. This requirement of the Consent Decree does not apply to the existing heater and a new O2 CEMs will be installed once the heater has been reconstructed.

Response #21 Ohio EPA concurs with the applicant, and deleted the date.

Comment #22 Page 42, term C.2.d)(12)d., emissions unit B004 – same as Comment #14, add language to heater design documents…"demonstrating the use of heat recovery and O2 monitoring"

Response #22: Ohio EPA concurs with the applicant, and added the language.

Comment #23 Page 47, term C.2.f)(1)h., emissions unit B004 – similar to Comment #15,the draft compliance demonstration language for the SO2 emissions limit of 67.62 tons SO2 per 12-month rolling period, does not include reference to the non-H2S sulfur concentration used in the application to estimate the SO2 emissions limit. Since the limit was calculated using both H2S and non-H2S values, the compliance demonstration language should also use both. Revise the first sentence to: "Compliance shall be based upon the fuel flow and H2S monitoring and record keeping requirements specified in sections d)(2) through d)(5) plus a 50 ppmv allowance for non-H2S sulfur based on EPA published refinery test data, or more recent test value if future testing is performed."

Response #23: Ohio EPA concurs with the applicant, and revised the language accordingly.

Comment #24: Page 47, term C.2.f)(1)i., emissions unit B004 – same as Comment #16, there is a typographical error, "GHG MMR rule" should read "GHG MRR rule".

Response #24: Ohio EPA concurs with the applicant, and corrected the typographical error.

Comment #25: Page 51, term C.3.c)(1)m., emissions unit J011 – typographical error, permit condition "c)(1)m." should be "c)(1)a." Also, please revise the annual throughput limit to 76,650,000 gallons based on a 12-month summation. (Likewise, please update the cumulative throughput allowed in the first 12 months.) The proposed emission limit of 1.74 tpy VOC, which is the PTE for this new source is based on this annual throughput, not the 57,855,420 gallons listed in the draft permit. That number (57,855,420 gallons/yr) is equivalent to 3774 BBL/day and relates to the projected increased throughput of the existing decanted oil DO tanks.

We believe the permit limit for the railcar loading should represent the loading rack PTE (76,650,000 gallons/yr).

Response #25: Ohio EPA concurs with the applicant, corrected the typographical error, and revised the annual throughput and cumulative throughput gallons.

Comment #26: Page 53, term C.3.f)(1)a., emissions unit J011 – consistent with Comment #25, the applicable compliance method should be updated. The emissions limit (PTE) given in the permit of 1.74 tpy VOC is based on a maximum throughput of 76,650,000 gallons per year. Please replace 57,855,420 with 76,650,000 for consistency.

Response #26: Ohio EPA concurs with the applicant and revised the annual throughput.

Comment #27: Page 54, term C.4., emissions unit P005 – Please revise the description of the emissions unit to "Delayed Coking process unit including two Coker Drums…" EU P005 includes the entire Coker unit, not just the modified equipment.

Response #27: Ohio EPA concurs with the applicant and changed the emissions unit description.

Comment #28: Page 55, term C.4.b)(1)j., emissions unit P005 – consistent with Comment #4, please delete the permit reference to NSPS, Subpart GGGa. The requirements of NSPS, Subpart GGGa do not apply to this emissions unit because the changes planned do not meet the definition of modification in NSPS, Subpart GGGa. This rule applies to emissions sources, not just new components, so these requirements do not only apply to the new components. They will not apply at all.

Response #28: Ohio EPA concurs with the applicant and deleted the rule.

Comments #29: Page 55, term C.4.b)(1)l., emissions unit P005 – Please revise reference to "See b)(2)k" instead of "See b)(2)l"

Response #29: Ohio EPA concurs with the applicant and changed to reference to "See b)(2)k".

Comment #30: Page 55, term C.4.b)(2)a., emissions unit P005 – The exemption in this draft permit condition to the requirements of OAC 3745-17-11 applied to P005 before the COF project, but after COF, the new coke handling portion of P005 will become subject to the 17-11 requirements. However, the proposed BAT emissions limits under OAC 3745-31-05(D) are more stringent than the limits estimated per the 17-11 requirements. With an estimated 20.4 ton/yr Process Weight Rate from the Coker, the hourly limit from 17-11 Appendix A would be approximately 30.5 lb/hr PM, which is less stringent than the 11.6 tons/yr BAT limit. Therefore, we request this condition be replaced with the following language: "The PE emissions limits proposed under OAC 3745-31-05(D) are more stringent than the emission limit pursuant to OAC rule 3745-17-11; therefore, compliance with 17-11 shall be demonstrated by compliance with 31-05(D)."

Response #30: The emissions unit is not subject to OAC rules 3745-17-11(B) and 3745-17-07(A) (no stack particulate emissions). It is, however, subject to OAC rules 3745-17-08(B) and 3745-17-07(B), but there are no emission limitations and/or control measures/requirements established because the facility is not located within the areas identified in "Appendix A" of OAC rule 3745-17-08 (it is located in Allen County). Therefore, the requirements of OAC rule 3745-17-08(B) do not apply to this emissions unit. Also, this emissions unit is exempt from the visible particulate emission limitations specified in OAC rule 3745-17-07(B), pursuant to OAC rule 3745-17-07(B)(11)(e).

Comment #31: Page 55, term C.4.b)(2)b., emissions unit P005 – Similar to Comment #30, the exemption in this draft permit condition to the requirements of OAC 3745-17-07(A) will no longer apply after the modifications proposed in the COF project. Therefore, 17-07 will apply but the proposed visible VE limit under OAC 3745-31-05(D) is more stringent than the limit estimated per the 17-07(A). Therefore, we request this condition be replaced with the following language: "The visible PE emissions limits proposed under OAC 3745-31-05(D) are more stringent than the emission limit pursuant to OAC rule 3745-17-07(A); therefore, compliance with 17-07(A) shall be demonstrated by compliance with 31-05(D).

Response #31: See response to comment #30 above..

Comment #32: Pages 55 and 56, term C.4.b)(2)d, emissions unit P005 – We request the following clarification language: Add the following language to the third paragraph of this condition: "…the permittee has committed to perform the following control measure(s) when the unit is in operation to ensure…" Also, when the coke product drop out of the coke drum, it is hydro blasted and therefore, is inherently wet. For this reason, we request that the control measure for the coke product drop be revised as follows: "Inherently wet coke product from saturation during removal" ~~*(Saturate coke product with water)*~~In addition, we request that the control measure for the removal of coke product from coke pit with front-end loader be clarified as follows: "Inherently wet coke product from saturation (apply water if necessary)"

Response #32: Ohio EPA concurs with the applicant, and added the suggested clarification language.

Comment #33: Page 56, term C.4.b)(2)e., emissions unit P005 – Consistent with Comments #4 and #28, we request the following deletions from this permit condition to clarify that the requirements of NSPS, Subpart GGGa do not apply to the Coker Unit after the COF modifications: Paragraph 1 – "The Coker process unit (~~actual vessel~~) is not…"; Paragraph 2 – "New and modified piping components associated with this emissions unit are subject to ~~LDAR requirements in 40 CFR, Part 60, Subpart GGGa, specifically 40 CFR 60.640a through 60.679a. In addition, the new and modified piping components are subject to~~ the appropriate provisions…"

Response #33: Ohio EPA concurs with the applicant, and deleted the strikeout sections.

Comment #34: Page 57, term C.4.b)(2)j. and C.4.b)(2)k., emissions unit P005 – Permit condition 4.b)(2)k is actually the BACT requirement for this emissions unit. For this reason, we request that permit condition 4.b)(2)k be deleted/moved and this BACT requirement instead listed in condition 4.b)(2)j. as follows: ~~Use of good combustion practices~~ The permittee shall depressurize each coke drum to 5 pounds per square inch gage (psig) or less prior to venting the coke drum steam exhaust to the atmosphere. When the pressure exceeds 5 psig, vent gases must be routed to the refinery fuel gas system, the FCC/coker flare (emissions unit P006), or other control device prior to opening the vent to the atmosphere." (Note: No combustion occurs in the coke drums thus good combustion practices is incorrect)

Response #34: Ohio EPA concurs with the applicant, deleted the strikeout section, and moved the term to b)(2)j.

Comment #35: Pages 55 and 57, term C.4.b(1)l. and C.4.b)(2)k., emissions unit P005 – Draft permit condition b)(1)l (NSPS Ja) references b)(2)l, but there is no permit condition b)(2)l. for this reason, we request that this reference be changed to b)(2)k, and that a new b)(2)k be added with the following language: "Compliance with permit condition b)(2)j demonstrates compliance with requirements of 40 CFR 60 Subpart Ja."

Response #35: Ohio EPA concurs with the applicant, and added the new term b)(2)k.

Comment #36: Page 57, term C.4.d)(1), emissions unit P005 - The coke product dropped into the coke pit operation is inherently wet because the coke is hydro-cut from the coke drum and visible dust emissions would not be expected from this operation. For this reason, we request that no inspection be required for this particular coke handling operation and that this reference be deleted. (Note: the subsequent coke handling steps will still be inspected regularly).

Response #36: Ohio EPA concurs with the applicant, and deleted this inspection requirement.

Comment #37: Page 58, term C.4.d)(3), emissions unit P005 – Currently, the draft permit does not include any monitoring or record keeping requirements to demonstrate compliance with NSPS Ja or the BACT requirement proposed for GHG's. We request that a new permit condition, referenced as 4.d)(3) be added to the permit to demonstrate compliance with the BACT limit and the NSPS Ja requirement for minimum depressuring requirement. This condition may read as follows: "The permittee shall record the pressure inside the coke drum prior to discharging the coke drum to the atmosphere."

Response #37: Ohio EPA concurs with the applicant, and added the suggested monitoring term 4.d)(3).

Comment #38: Page 58, term C.4.e)(1), emissions unit P005 – Consistent with Comment #37, we request that a new permit condition, referenced as 4.e)(1) be added to the permit to demonstrate compliance with the BACT limit and the NSPS Ja requirement for minimum depressuring requirement. This condition may read as follows: "c. All periods when the blow down vent vapors were vented to the atmosphere without first depressuring the coke drum to less than 5.0 psig; and the actual coke drum pressure prior to venting, for each such event."

Response #38: Ohio EPA concurs with the applicant, and added the suggested reporting term 4.e)(1)c.

Comment #39: Page 63, term C.5.b)(2)c., emissions unit P037 – typographical error, 37435-17-11(B) should read 3745-17-11(B).

Response #39: Ohio EPA concurs with the applicant, and corrected thetypographical error.

Comment #40: Page 63, term C.5.c)(1)a., emissions unit P037 – We propose the following clarification to indicate the averaging period for the total dissolved solids limit. "The permittee shall not exceed a total dissolved solids (TDS) content of 5,600 mg/l (monthly average) in the cooling water for this emissions unit; and"

Response #40: Ohio EPA concurs with the applicant, and added "as a monthly average" to the TDS limit.

Comment #41: Pages 63 and 65, terms C.5.d)(2), C.5.d)(7) and C.5.e)(2), emissions unit P037 – Currently, this condition is the only reference under the permit terms and conditions to the requirements of the heat exchanger requirements in 40 CFR 63.654. We request that the monitoring and record keeping requirements be added to the permit terms and conditions.

We propose adding condition 5.d)(2) to read as follows: "Perform monitoring to identify leaks of total strippable volatile organic compounds (VOC) from each heat exchange system subject to the requirements of 40 CFR 63.654 according to the procedures in paragraphs (c)(1) through (6) of 63.654." Adding condition 5.d)(2) will increase the numbering for existing sections 5.d)(2) – 5.d)(5) by one each to 5.d)(3) – 5.d)(6). We propose adding condition 5.d)(7) as follows: "If a leak is detected, during the monitoring performed per d)(2) above, repair the leak to reduce the measured concentration to below the applicable action level as soon as practicable, but no later than 45 days after identifying the leak, except as specified in paragraphs 40 CFR 63.654(e) and (f). Repair includes re-monitoring at the monitoring location where the leak was identified according to the method specified in paragraph 40 CFR 63.654(c)(3) to verify that the measured concentration is below the applicable action level." We propose adding condition 5.e)(2). "Comply with the reporting requirements for heat exchange systems subject to 40 CFR 63.654 requirements in 40 CFR 63.655."

Response #41: Ohio EPA concurs with the applicant, and revised the terms accordingly.

Comment #42: Pages 68 and 69, term C.6.b)(1)e., emissions unit P040 – The CO limits that are included in this draft permit condition are not correct. The modification to the SRU for O2 enrichment will not change the existing CO performance on these emissions units. In addition, the netting analysis and the modeling in the permit application submitted for the COF permit were based on the existing CO limits for this source. For these reasons, we request that the CO lb/hr and tpy limits be revised back to the existing CO limits for the existing SRU as follows: "1.88 ~~1.55~~ lb of carbon monoxide (CO)/hr and 8.23 ~~6.77~~ tons of CO/rolling, 12-month period."

Response #42: Ohio EPA concurs with the applicant, and changed the CO emission limits back to the original limits.

Comment #43: Pages 68 and 69, term C.6.b)(1)e., emissions unit P040 – In order to clarify the averaging period, we request the following revisions to the language referencing the SO2 limits: 19.18 lbs of sulfur dioxide (SO2)/hr, as a 12-hr rolling average; 84.02 tons of SO2/rolling, 12-month ~~hour~~ period; and 250 parts per million by volume (dry basis) of SO2 at 0% excess air as a 12-hr rolling average.

Response #43: Ohio EPA concurs with the applicant, and added the clarifying averaging periods.

Comment #44: Page 69, term C.6.b)(1)f., emissions unit P040 – In order to clarify which vent is subject to the miscellaneous Group 1 process vent provisions of 40 CFR 63 Subpart CC, please revise the description under the "Applicable Rule/Requirements" column to read as follows: [In accordance with 40 CFR 63.640, the rich amine flash drum that is part of this emissions unit is an affected source since it contains a Group 1 process vent~~s~~ that is ~~are~~ routed…"

Response #44: Ohio EPA concurs with the applicant, and added the clarifying language.

Comment #45: Page 69, term C.6.b)(1)h., emissions unit P040 - The Consent Decree (CD) requires that this unit be subject to the requirements of NSPS J until the CD expires; however, with the COF project modification to this unit, the SRU requirements of newer NSPS Ja are also triggered. Therefore, the SRU requirements of both NSPS J and Jaapply to the SRU. We request that both be referenced. (Note: the emissions limit of 250 ppm SO2 is the same for both J and Ja).

Please add the requirements of NSPS Ja: 40 CFR, Part 60, "Subpart Ja, 40 CFR 60.102a(f)(1)" and please clarify the averaging time "250 parts per million by volume (dry basis) of SO2 at 0% excess air, as a 12-hour rolling average" (Note: The tail gas incinerator is not being modified by COF project and will not trigger the fuel gas combustion device H2S requirements of NSPS Ja. Instead, the fuel H2S requirements of NSPS J will continue to apply to the incinerator fuel. These are stated in 6.b(1)(u) and 6.b(2)q.)

Response #45: Ohio EPA concurs with the applicant, and added the clarifying language to reference both NSPS, Subparts J and Ja.

Comment #46: Page 70, term C.6.b)(1)r., emissions unit P040 – In order to clarify which parts of the SRU are subject to the requirements of 40 CFR, Part 61, Subpart FF, please revise the description under the "Applicable Rules/Requirements" column to read as follows: "[In accordance with 40 CFR 61.340, the sour water components of this emissions unit are an affected source…"

Response #46: Ohio EPA concurs with the applicant, and added the clarifying language.

Comment #47: Page 71, term C.6.b(2)b., emissions unit P040 - Please include the following paragraph in this condition for clarification: "The OAC rule 3745-18-08 SO2 limit of 100 lb SO2/1,000 lb sulfur processed is less stringent than the limit established under OAC rule 3745-31-10 through 31-20, and less stringent than the standard required by 40 CFR 60 Subpart Ja. Compliance with this limit will be demonstrated through compliance with OAC rule 3745-31-10 through 31-20 and NSPS Ja." (Note: The 18-08 limit equates to about 95% recovery of sulfur in the SRU whereas the NSPS Ja limit of 250 ppm in the stack equates to over 99% recovery.)

Response #47: Ohio EPA concurs with the applicant, and added the clarifying paragraph.

Comment #48: Page72, term C.6.b(2)i., emissions unit P040 – The limit in the draft permit of 1.55 CO/hr is different from the current limit on this emissions unit of 1.88 lb/hr. We request that the current limit of 1.88 lb/hr be retained. The modification of this unit will not change the maximum potential emissions of CO (or any other pollutant) and there is no need to change this limit. The CO PSD netting and modeling all were based on the net increase from baseline up to the current limit/PTE of 1.88 lb/hr (8.23 tons/yr). The lower number appears to have inadvertently been presented in the application as a projected future rate for this unit, but it is not PTE and was not used in the permit evaluation. The language below represents the requested changes: "1.88 ~~1.55~~ lb of CO/hr;"

Response #48: Ohio EPA concurs with the applicant, and will retain the 1.88 lb of CO/hr limit.

Comment #49: Page 73, term C.b)(2)l. and 6.b)(2)m., emissions unit P040 – Please add the following clarifying language to this permit condition to specify which part of the SRU is subject to the Group 1 miscellaneous process vent requirements in 40 CFR 63.641: "…meets the requirements of 40 CFR 63.11(b) of Subpart A for emissions from the rich amine flash drum." "…Subpart CC are applicable for the ~~each~~ Group1 process vent that is part of this emissions unit, the rich amine flash drum, and is route to either…" (Note: this is not a change associated with this project, but merely an opportunity to provide this clarifying language.)

Response #49: Ohio EPA concurs with the applicant, and added the clarifying language.

Comment #50: Page 74, term C.6.b)(2)p., emissions unit P040 – Please add the following language to clarify which parts of this emissions unit are subject to the benzene waste operations program: "The permittee shall include the sour water components of this emissions unit, SRU 1 & 2, in the current site benzene waste operations program"

Response #50: Ohio EPA concurs with the applicant, and adding the clarifying language.

Comment #51: Page 76, term C.6.d)(3)c., emissions unit P040 – (Consistent with Comment #46 regarding requested insert on Page 75 regarding OAC rule 3745-18-08) Please delete this recordkeeping requirement from the permit. As mentioned above, compliance with this 18-08 requirement can be demonstrated through compliance with the requirements of NSPS Ja and the SO2 tpy annual emissions limit. Separate record keeping for 18-08 is unnecessary.

Response #51: Ohio EPA concurs with the applicant, and deleted this recordkeeping requirement.

Comment #52: Pages 80 and 81, term C.6.f)(1)e., emissions unit P040 - Consistent with previous Comment #47 regarding page 76 CO limit, we request that the existing limit for CO emissions for the SRU 1 & 2 be retained (i.e.: not changed in this permitting). Additionally, the original permit limit, and the calculations used in the COF permitting used a vendor performance factor of 100 ppm, not the standard AP-42 factor (although they are very similar). Please make the following changes to this draft permit condition: "Emission Limitation: 1.88 ~~1.55~~ lbs of CO/hr and 8.23 ~~6.77~~ tons of CO/rolling, 12-month period, combustion emissions from the tail gas incinerator. Applicable Compliance Method: The ~~permittee~~ CO emissions limitation was derived from a vendor guarantee of a maximum CO emissions rate of 100 ppm. ~~may demonstrate compliance with the hourly limitation by multiplying the appropriate CO emission factor of 84 pounds per million standard cubic feet, from AP-42 Chapter 1.4 (7/98), by the maximum fuel flow rate of 18,431 standard cubic feet/hr.~~

Response #52: The company referred to Comment #47, when it is actually Comment #48 for CO emissions limit. Regardless of that typographical error, Ohio EPA concurs with the applicant, and changed the compliance demonstration language based on vendor guarantee of 100 ppm CO for 1.88 lbs of CO/hr and 8.23 tons of CO/rolling, 12-month period.

Comment #53: Page 81, term C.6.f)(1)g., emissions unit P040 – Please include the clarification that this emissions limit is a 12-hr rolling average. These emission limits are based on the NSPS required 250 ppm SO2 standard, which is based on 12-hr rolling average.

Response #53: Ohio EPA concurs with the applicant, and added the clarifying language for rolling limit.

Comment #54: Page 82, term C.6.f)(1)h., emissions unit P040 – Please include the clarification that this emissions limit is a 12-hr rolling average.

Response #54: Ohio EPA concurs with the applicant, and added the clarifying language for rolling limit.

Comment #55: Page 82, term C.6.f)(1)i., emissions unit P040 – Please delete this less stringent requirement from the permit. As mentioned above, compliance with this requirement can easily be demonstrated through compliance with the requirements of NSPS Ja and the SO2 tpy annual emissions limit.

Response #55: Ohio EPA concurs with the applicant, and deleted this permit term.

Comment #56: Page 84, term C.7.b)(1)a., emissions unit P049 – We request clarifying language be added to clarify which part of the SRU is subject to Subpart CC. Also, please delete reference to OAC rule 3745-18-08(C)(3). The requirements in 18-08(C)(3) are only in reference to the existing SRU (P040) in the Ohio SIP. This requirement will not apply to the new SRU 3 (although it's permitting emissions are significantly below the requirement of this SIP standard. Requested change: "…Subpart CC (for the rich amine flash drum); 40 CFR 60.104(a) ~~and OAC rule 3745-18-08(C)(3)~~."

Response #56: Ohio EPA concurs with the applicant, added the clarifying language and deleted reference to OAC rule 3745-18-08(C)(3).

Comment #57: Page 85, term C.7.b)(1)e., emissions unit P049 – Please clarify that the short-term SO2 limits included in this permit condition are 12-hour rolling averages instead of 12-hour block averages.

Response #57: Ohio EPA concurs with the applicant, and added the clarifying language for rolling limit.

Comment #58: Page 85, term C.7.b)(1)f., emissions unit P049 – Please revise the description under "Applicable Rules/Requirements" to clarify which portion of the unit is subject to Subpart CC"…"Miscellaneous Group 1 process vent provisions for the new rich amine flash drum"

Response #58: Ohio EPA concurs with the applicant, and added the clarifying language.

Comment #59: Page 86, term C.7.b)(1)q., emissions unit P049 - Please revise the description under "Applicable Rules/Requirements" to clarify which portion of the unit is subject to the referenced rule: "[In accordance with 40 CFR 63.340, the sour water components of this emissions unit are ~~is~~ an affected source…"

Response #59: Ohio EPA concurs with the applicant, and revised the description.

Comment #60: Page 87, term C.7.b)(2)g., emissions unit P049 – Please add clarifying language to the BACT emissions limits for CO2 to clarify where the low-carbon fuel is used: "…as supplemental fuel in the tail gas incinerator"

Response #60: Ohio EPA concurs with the applicant, and added the clarifying language.

Comment #61: Page 88, term C.7.b)(2)k., emissions unit P049 – Please add the following clarifying language to the second paragraph of the permit condition: “The burning of gaseous fuels in the tail gas incinerator is the only source of PE from this emissions unit.”

Response #61: Ohio EPA concurs with the applicant, and added the clarifying language.

Comment #62: Page 89, term C.7.b)(2)m., emissions unit P049 – In the regulatory reference table, next to the requirements for 63.1570(a), please add the following clarifying statement: “Compliance with Non-opacity Standards during times specified in 40 CFR 63.6(f)(1).”

Response #62: Ohio EPA concurs with the applicant, and added the clarifying language.

Comment #63: Page 89, term C.7.b)(2)o., emissions unit P049 – Please add the following language to clarify which parts of this emissions unit are subject to the benzene waste operations program: “The permittee shall include the sour water components of the new Claus 3 sulfur recovery unit in the current site benzene waste operations program”

Response #63: Ohio EPA concurs with the applicant, and added the clarifying language.

Comment #64: Page 95, term C.7.f)(1)a., emissions unit P049 – (Typo) The emission factor under the Applicable Compliance Method is incorrect. Please correct the emission factor from emissions of PE/PM10/PM2.5 from combustion to 7.6 pounds per million standard cubic feet instead of 1.9 lb/mmscf. (Note: The incorrect 1.9 factor matches the AP-42 “filterable” factor. The correct 7.6 factor includes both filterable and condensable, and is the value used in determining the emission limit.)

Response #64: Ohio EPA concurs with the applicant, and corrected the emission factor to 7.6 pounds per million standard cubic feet.

Comment #65: Pages 97 and 98, term C.7.f)(1)f., emissions unit P049 – The draft permit’s applicable compliance method for the emissions limit of CO2 is not exactly consistent with the emissions calculations in the COF permit application. We propose the following revisions to clarify the calculation methodology to make it consistent with the basis of the limits: “The rolling, 12-month limitation represents ~~the potential to emit~~ estimated emissions at the ~~see b)(2)f. based on a~~ maximum design sulfur load ~~ratio~~ of 195 long tons per day which is estimated to result in 21,098 scfm of stack gas flow and an assumed 6.3% CO2 concentration in the stack based on past stack testing of the existing SRU unit ~~to 160 long tons per day (21.875 percent higher operating rate for emissions unit P049 compared to P040. Thus,~~ the resulting calculated GHG emissions are 40,512 tons per rolling, 12-month period. Compliance shall be demonstrated by ~~maintaining the fuel flow rate at less than or equal to 22,000 standard cubic feet per hour on a 12-month rolling average~~ use of actual stack flow rates and an assumed 6.3% CO2 concentration in the stack (for other more recent test data, if available).

Response #65: Ohio EPA concurs with the applicant, and revised the applicable compliance method.

Comment #66: Page 98, term C.7.f)(1)g. and C.7.f)(1)h., emissions unit P049 – Please add language to clarify that these limits are 12-hour rolling averages instead of 12-hour block averages.

Response #66: Ohio EPA concurs with the applicant, and added the clarifying language for rolling limit.

Comment #67: Page 101, term C.8.b)(1)a., emissions unit P050 - Please add language to clarify that the emissions limits established for PE/PM10/PM2.5 and VOC are from the combustion of the pilot and sweep gases only. This flare is an emergency only flare, and does not receive any other routine flare load and the COF project does increase the likelihood or frequency of any emergency, Startup, Shutdown or Malfunction emissions.

Response #67: Ohio EPA believes a word was omitted from this comment, that it should read, "the COF project does ***not***increase the likelihood…" Regardless, Ohio EPA concurs with the applicant, and added the clarifying language for pilot and sweep gases only, as the agency understands this flare is an emergency only flare.

Comment #68: Page 102, term C.8.b)(1)e. and C.8.b)(1)f., emissions unit P050 - (Consistent with Comment #7 regarding MACT UUU on page 14) Please delete these permit citations. Even though the acid gas flare is used to control Startup/Shutdown/Malfunction emissions from the SRUs, this is not required for compliance with 40 CFR 63 Subpart UUU. This rule does not apply to the new Acid Gas flare and we request that it not be referenced here.

Response #68: Ohio EPA concurs with the applicant, and deleted the MACT, Subpart UUU rule citations.

Comment #69: Page 102, term C.8.b)(1)j., emissions unit P050 – Similar to above comment regarding VOC and PM, please clarify that these emissions limits are from the combustion of the pilot and sweep gases only and do not apply to the SSM events for this flare.

Response #69: Ohio EPA concurs with the applicant, and added the clarifying language.

Comment #70: Page 102, term C.8.b)(2)b.i., ii. and iv., emissions unit P050 – Please add the following language to clarify which emissions limits are from the combustion of pilot and sweep gases and which are for SSM events. i. From pilot and sweep gas firing only – 0.02 ton PE/PM10/PM2.5/rolling, 12-month period, ii. From pilot and sweep gas firing only – 0.32 ton VOC/rolling, 12-month period; iii. 1.00 ton of NOx/yr during periods of process unit start-up and shutdown; and iv. 100.00 tons of SO2/yr during periods of process unit start-up and shutdown. The emission limitations for NOx and SO2 during start-up and shutdown were established to alleviate reporting requirements associated with reportable quantities (RQ)…

Response #70: Ohio EPA concurs with the applicant, and added the clarifying language.

Comment #71: Page 103, term C.8.b)(2)c., emissions unit P050 – Please clarify that the requirement to use clean gaseous fuel related to the pilot and sweep gases only and do not apply to the SSM events for this flare.

Response #71: Ohio EPA concurs with the applicant, and added the clarifying language.

Comment #72: Pages 103 and 104, term C.8.b)(2)g., emissions unit P050 – (Consistent with Comment #7 and Comment #67 regarding UUU non-applicability) Please revise this permit condition. Even though the acid gas flare is used to control Startup/Shutdown/Malfunction emissions from the amine units covered by P049 and P040, this is not required for compliance with 40 CFR 63 Subpart UUU. "This flare will be used to control H2S emissions ~~from each~~ in the feed stream to the sulfur recovery units (Claus 1, Claus 2 and Claus 3 units) emissions units P040 and P049, during periods of start-up, shutdown and malfunction of those emissions units and associated equipment. The Claus sulfur recovery units are subject to MACT standards in 40 CFR, Part 63, Subpart UUU, but this flare as a control device for the amine units that feed the Claus units is not an affected source subject to the requirements of Subpart UUU."

Response #72: Ohio EPA concurs with the applicant, and revised the permit term.

Comment #73: Page 104, term C.8.b)(2)i.i., emissions unit P050 – Please add the following regulatory reference to the flare management plan requirement: "i. Develop and implement a written flare management plan in accordance with 40 CFR 60.103a(a)(1) through (7);"

Response #73: Ohio EPA concurs with the applicant, and added the regulatory reference.

Comment #74: Page 104, term C.8.b)(2)j., emissions unit P050 – Please clarify that the BACT requirement to use low-carbon gaseous fuels are regarding the fuel used as pilot and sweep gases.

Response #74: Ohio EPA concurs with the applicant, and added the clarifying language.

Comment #75: Page 105, term C.8.c)(3), emissions unit P050 – Please add the following clarifying since the requirements of 60.18 would not apply independently to the new acid gas flare:

"(3) This flare shall be operated using good combustion practices as BACT which shall be demonstrated by complying with the following flare requirements of 40 CFR 60.18 (although 40 CFR 60.18 is not otherwise applicable)."

Response #75: Ohio EPA concurs with the applicant, and added the clarifying language.

Comment #76: Pages 107 through 109, terms C.8.f)(1)a., C.8.f)(1)b., C.8.f)(1)f., C.8.f)(1)g.,C.8.f)(1)h. and C.8.f)(1)i., emissions unit P050 – Please add language to the "Applicable Compliance Method" and the emissions limitations in these specific permit conditions to clarify that these limits and the "maximum heat input" in the Applicable Compliance Method are from the combustion of the flare's pilot and sweep gases only. This flare is used occasionally for SSM events, but those emissions are regulated by separate limits (8.f)(1)c, d & e).

Response #76: Ohio EPA concurs with the applicant, and added the clarifying language.

2. Topic: The Alliance for the Great Lakes (The Alliance) submitted a total of three written comments regarding the potential for discharges into Lake Erie from the project, since the facility discharges water into the Ottawa River, located adjacent to the refinery, which flows into Lake Erie.

Comment #1: New cooling water discharge: The Lima Refining/Husky draft permit includes a reference to increased cooling tower water circulation in Cooling Tower LIU. According to Ohio EPA, Lima Refining/Husky will seek an additional outfall in a revised NPDES permit to accommodate the increased non-contact cooling water cooling. Ohio EPA has not yet received a formal modification request from the facility.

The Alliance believes that it is imperative that any new discharges and any new proposed outfall be subject to requirements under the Clean Water Act and limits at least as protective as in the existing NPDES permit. Granting the air pollution permit does not have a specific bearing on whether the NPDES will be modified, however, granting the permit and allowing construction makes it all the more likely.

In addition, the Alliance would appreciate additional information concerning the location of the proposed new cooling water outfall as well as whether the increased use of cooling water will require additional intakes and/or increase the volume and/or velocity of intake water.

Response #1: The crude oil flexibility project involves the modification of the LIU cooling tower, emissions unit P037. However, air pollution permits-to-install only regulate air pollutant emissions (particulate and volatile organic compounds) from the cooling tower itself, not the cooling water discharge. The wastewater permitting is done by Ohio EPA, Division of Surface Water.

Information on the type of wastewater permit required for the crude oil flexibility project, along with cooling water outfall location, can be obtained from the Division of Surface Water, Ohio EPA, Northwest District Office, 347 N. Dunbridge Rd., Bowling Green, OH 43402.

Comment #2: Benzene Wastewater: According to the Lima Refining/Husky draft permit, the facility is an affected source due to processing of wastewater containing benzene. The Alliance urges Ohio EPA to explain whether modifications to the air permit would have an effect on this program, in addition to any potential effects on a modification to the existing NPDES permit. U.S. EPA has issued guidance on National Emission Standards for Hazardous Air Pollutants (NESHAP) and all applicable requirements should be reflected in the permit.

Response #2: The benzene NESHAPS program regulations are found in 40 CFR, Part 63, Subpart FF. Ohio EPA has full delegation of authority from U.S. EPA to administer these regulations, with the exception of section 40 CFR 61.353 – Alternate Means of

Emission Limitation. Two emissions units in this air permit-to-install are subject to the benzene NESHAPS program, P040 and P049, which are the three Claus sulfur recovery units (P040 is Claus 1 and Claus 2, P049 is Claus 3). The following terms in the air permit-to-install state that P040 and P049 have the applicable requirements in 40 CFR 61.340 through 61.358, and that the facility must comply with all applicable requirements in these regulations: Facility-wide term B.9., and Emission Unit terms C.6.b)(1)r., C.6.b)(2)p., C.7.b)(1)q. and C.7.b)(2)o.

Comment #3: According to the Toxic Report Inventory for 2012, Lima Refinery discharged 6.25 pounds of mercury from its air stack and 0.3 pounds of mercury into the water. The draft air pollution permit does not discuss any potential increases of mercury as a result of the increased operations. The Alliance urges Ohio EPA to explain how mercury releases will be minimized as a result of increased operations. EPA's NESHAP program also includes provisions for mercury monitoring and compliance which should be reflected in permit as applicable.

Response #3: Ohio EPA requested supporting documentation from the company for mercury releases as reported in the Toxic Release Inventory for 2012 (not the Toxic Report Inventory as noted by commenter). They submitted an itemized list with the annual mercury releases to air for each emissions unit. The majority of mercury release to the air does not occur from emissions units in the crude oil flexibility project, but rather from the Fluid Catalytic Cracking Unit (FCCU) and associated electrostatic precipitator for the FCCU (4.08 lbs of the total 6.25 lbs reported).

Mercury Releases to Air: Existing emissions units associated with the project had the following reported annual mercury releases to air in 2012:

B001: 0.07 lb

B004: 0.60 lb

B027: 0.00 lb (amount is rounded down to 0.00 lb)

P040: 0.02 lb

Total: 0.69 lb

In addition, the company stated that two new emissions units in the project, P049 - Claus 3 sulfur recovery unit and P050 – acid gas flare for sulfur recovery units, will have estimated emissions very similar to the P049, existing sulfur recovery unit, since the same emission factor is used. Thus, each of these two new emissions units will have an estimated maximum of 0.02 lbs of mercury released to air.

Thus, the expected additional mercury release to air would be 0.04 lbs/yr. This level of emissions is insignificant, and mercury monitoring would be cost prohibitive.

Mercury Releases to Water: The company stated that the 0.3 lbs of mercury released to water is incorrect. The correct amount is 0.03 lbs in 2012. Since the air pollution permit-to-install does not regulate wastewater discharges, this comment is unrelated to the permit-to-install. Any concerns about mercury in wastewater would need to be addressed separately with the Division of Surface Water.

3. **Topic: A total of 11 other letters were received with written comments during the public comment period. All of the commenters were in favor of the project, with no response required from Ohio EPA. The commenters included:**

   Jim Jordan, United States Congressman, Ohio 4th District

   Jeff Sprague, President & CEO, Allen Economic Development Group

   Russ Holly, Dave Belton and Chris Seddelmeyer, Shawnee Township Board of Trustees

   Matt Huffman, State Representative, 4th Ohio House District

   Patricia Smith, Director/Executive Secretary, Allen County Museum/Allen County Historical Society

   Jed Metzger, President/CEO, Lima/Allen County Chamber of Commerce

   Aubree Kaye, Executive Director, Downtown Lima, Inc.

   Robert Baxter, President & CEO, St. Rita Health Partners

   Todd Truesdale, Fire Chief, Shawnee Township Fire Department

   Brian Rockhold, Superintendent, Allen County Educational Service Center

   Judith Cowan, President & CEO, Ohio Energy & Advanced Manufacturing Center

4. **Topic: Testimony at October 1, 2013 public hearing:** a total of 8 people testified at the public hearing, and all were in favor of the project, with no response required from Ohio EPA. Those testifying included:

   Dave Berger, Lima Mayor

   Mike Knisley, President, Lima Building Trades Council

   Roy Warnock, Vice President and General Manager, Husky U.S. Refining

   Jed Metzger, President/CEO, Lima/Allen County Chamber of Commerce

   David Belton, Shawnee Township Board of Trustees

   Nell Lester, Lima/Allen County Neighborhoods and Partnership

   Jeff Sprague, President & CEO, Allen Economic Development Group

   Jay Begg, Allen County Commissioner

5. Topic: U.S. EPA, Region V, submitted a total of 21 written comments as follows:

Comment #1: The cost analysis for selective catalytic reduction (SCR) as Best AvailableControl Technology (BACT), as provided on p. 5-10 of the permit application,has several discrepancies from the Office of Air Quality and Planning StandardsCost Control Manual (CCM) which is referenced in various sections as the basisfor calculations. The CCM indicates that for SCR, there should be no additionallabor costs, no additional supervisory labor, no property taxes, minimal insurance,insignificant administrative costs, and no overhead costs; however, the permitapplication's SCR analysis includes significant costs for all of these items. TheCCM indicates that for an SCR, the equipment life should be 20 years, but thepermit application uses 15 years. The cost of catalyst replacement incorrectlyuses a cost recovery factor instead of a future worth factor. It is unclear why thepermit application includes one percent of the cost of natural gas for the proposedheater toward the BACT cost analysis. Please provide an explanation fordeviating from the recommendations in the CCM or reevaluate the SCR BACT consistent with the CCM recommendations.

Response #1: After receiving this comment, Ohio EPA again reviewed our analysis of BACT for SCR plus ultra low-NOx burner (ULNB) cost effectiveness. We also asked Lima Refining Company to revise the cost effectiveness analysis provided in the application to align it with U.S. EPA's "Office of Air Quality Planning Standards Cost Control Manual (CCM)." Based on the second review, Ohio EPA concludes that the BACT described for NOx emissions sources was correct.

This conclusion is based, in part, on the following:

1. The revised cost-effectiveness study for add-on controls demonstrated that it was not cost effective to require add-on NOx controls. See the revised BACT study from URS, attached as Exhibit 1.

2. The original BACT analysis used generic factors for control device cost, however, in the revised BACT analysis, the company used the recommended factors from the CCM.

3. In the original BACT analysis, a 1 percent increased natural gas usage was assumed to reflect cost to overcome SCR increased stack pressure. In the revised BACT analysis, that approach was changed to the methods in the CCM, where the increased fan electricity cost is used to overcome the stack pressure.

Comment #2: The heater firing rate of 615.4 MMBtu/hr on p. 5-10 of the permit application isincorrect; it should be 624 MMBtu/hr as stated on p. 5-9.

Response #2: Ohio EPA recognized that the 615.4 mmBtu/hr heater firing rate was incorrect when reviewing the permit application and discussed this with Lima Refining Company. It was determined that 615.4 mmBtu/hr is the heater firing rate for the existing Crude II Heater. The correct heater firing rate is 624 mmBtu/hr after reconstruction of the emissions unit is completed for the crude oil flexibility project and was used to calculate the appropriate emissions limitations. In the SCR cost analysis, 615.4 mmBtu/hr was used erroneously, however, when the revised SCR cost analysis was submitted, the resulting cost analysis was minimally affected.

Comment #3: According to the calculations in Appendix A, Table A-6, the NOx baselineemissions for unit B004 is 0.029 lb/MMBtu, based on an average of all availablestack tests and the final 2013 consent decree NOx limit of 0.035 lb/MMBtu.However, the 0.035 lb/MMBtu limit was not in LRC's Title V permit until July15, 2013 (permit no. PO113610). Prior to that, the Title V NOx emission limit was0.10 lb/MMBtu (permit no. P0086638, issued January 11, 2012).

It would bemore appropriate to use the latter number to calculate the NOx baseline emissionsso that LRC is not taking credit for emission reductions resulting from the consentdecree limit. Please revise the calculations so that 0.10 lb/MMBtu is used insteadof 0.035 lb/MMBtu.

Response #3: In response to this comment, Lima Refining Company submitted stack test data for six stack tests for NOx conducted between September 14, 2004 and May 12, 2010 for emissions unit B004. The results indicated the following NOx emissions rates:

Test Date	NOx (lb/mmBtu)
September 14, 2004	0.032
May 25, 2005	0.029
May 24, 2006	0.030
May 2, 2008	0.026
April 29, 2009	0.030
May 12, 2010	0.027

These results indicate that NOx emissions are consistent, with an average emissions rate of 0.029 lb/mmBtu. Ohio EPA concurs that 0.029 lb NOx/mmBtu is appropriate to provide an estimate of past actual emissions, based on the large data set, and is a conservative approach. Thus, the allowable emissions rate of 0.10 lb NOx/mmBtu should not be used to classify past actual emissions for the baseline. Further, if the 0.10 lb/mmBtu value was used to calculate past actuals, the results would tend to lower the impact from the COF project, which is not representative.

U.S. EPA also commented about the 0.035 lb NOx/mmBtu final consent decree emissions limitations. The consent decree was issued final in 2007, not 2013. There have been no changes to the Crude II burners, nor any change in how the Crude II heater operates. Compliance with the 0.035 lb NOx/mmBtu emissions limit has been consistently demonstrated, including the time period three years before the consent decree was issued in 2007. Mention of the 0.035 lb NOx/mmBtu limitation in the permit application for the COF project was for informational purpose, and used to note that the company was not trying to take advantage of any past actual NOx emissions that would be above allowable level. They were also not trying to take credit for emissions reductions resulting from the consent decree (i.e. – there are no actual emissions reductions in this situation). In addition, the consent decree prohibits use of emissions reductions for the Crude II heater to avoid PSD/nonattainment area new source review permitting, and the COF project does not avoid PSD for NOx.

Comment #4: The permit application states that the SCR cost analysis for NOx is based on abaseline of 40 ppm that is required by New Source Performance Standards(NSPS) Subpart Ja. The cost analysis should not use 40 ppm as a baseline since itis required by NSPS; instead, the analysis should use 0.10 lb/MMBtu from TitleV permit no. P0086638, issued on January 11, 2012. Please revise the costanalysis so that 0.10 lb/MMBtu is used instead of 40 ppm.

Response #4: Ohio EPA disagrees with this comment. There are several reasons listed below that 0.04 lb NOx/mmBtu should be used as the baseline instead of 0.10 lb NOx/mmBtu:

- The Crude II heater has historically achieved NOx emissions rates much less than the 0.04 lb/mmBtu value. The six stack test results listed in Comment #3 response above indicate the average emission rate of 0.029 lb/mmBtu. In fact, the highest single hourly NOx emission rate measured during any of the six stack tests was 0.0342 lb/mmBtu. Use of a 0.04 lb/mmBtu value as the baseline represents a conservative approach and the company is maintaining compliance with an adequate margin without the need for additional controls;

- Stack test results support use of 0.04 lb/mmBtu, but this is not solely because this is an equivalent limit to the NSPS Subpart Ja required level. The NSPS Subpart Ja is not, by itself, sufficient for a particular numerical value to be used for BACT baseline;

- 0.04 lb/mmBtu does not take advantage of required controls in the consent decree. Crude II heater performance consistently has been better than 0.04 lb/mmBtu as shown through six stack tests. The heater performance pre-dates the consent decree, in fact. There have been no changes to the burners in the Crude II heater resulting from the consent decree;

- Basing the cost analysis section for BACT for adding SCR to the reconstructed Crude II heater on a hypothetical uncontrolled emission rate not representative of demonstrated compliant performance is inappropriate. If the heater were to achieve the suggest 0.10 lb/mmBtu emission rate, that would worsen performance by more than 345 percent (0.10 lb/mmBtu divided by 0.029 lb/mmBtu); and

- The original permit for this emissions unit has a limit of 0.10 lb NOx/mmBtu. However, this limit will no longer be used in the permit being issued for the COF project. This emissions limit is now obsolete, and any further use of this value is not a realistic emissions scenario, given that six stack tests show less emissions.

Comment #5: The NOx BACT analysis for unit B004 on p. 5-8 of the permit applicationconsiders combustion controls (ultra low-NOx burners, or ULNB) and thecombination of ULNB with SCR. The BACT analysis should also consider SCRwithout ULNB.

Response #5: Lima Refining Company submitted a revised BACT analysis for NOx considering use of SCR without ULNB (See Exhibit 1). This revised BACT analysis considers four case types, with a "top-down" approach:

Technology	Emissions (ppm)	Emissions (lb/mmBtu)
SCR + ULNB	4	0.004
SCR (without ULNB)	5.3	0.0053
ULNB	30	0.03
Baseline only*	40	0.04

* the baseline is performance of the existing uncontrolled heater

Also, see the comment responses to U. S. EPA comments #14 and #15 – the external flue gas recirculation (FGR) and selective non catalytic reduction (SNCR) are both considered as inferior control to the proposed control and thus, were not carried over into the BACT cost evaluation values.

Comment #6: The SCR cost effectiveness analysis on p. 5-10 of the permit application uses apower of 0.6 in its calculation for total capital investment. The "six-tenths-factorrule" is generally an oversimplification that should only be used in the absence ofother information. Please revise the cost capacity factor so that it accuratelyrepresents the equipment at LRC and provide justification for it or explain why noother information is available for calculating the cost capacity factor.

Response #6: This comment refers to the Crude II heater and the total capital investment for SCR for modifying theheater. Lima Refining company informed Ohio EPA that it used this equipment cost scaling technique to estimate the cost of adding SCR to the reconstructed Crude II heater, since detailed actual installation costs were readily available from recently installingSCR on a heater similar in size and configuration as the Crude II heater.

The company stated, and Ohio EPA agrees, that basing the SCR cost estimate on actual costs from controlling a similar heater at the same facility is a more accurate method than using other available methods. The Crude II heater is approximately 25 percent smaller than the Ultraformer Heater at the facility, which has actual SCR costs available. Thus, it is expected that the SCR costs for the smaller heater would be less than SCR for the larger heater, if all other design information is equal. Use of a six-tenths factor indicates that the cost of SCR for the slightly smaller heater would be approximately 16 percent lower than the costs for the larger heater.

Since there is a relatively minor difference in thesetwo heater sizes, this scaling factor does not result in a large cost adjustment, and thus, any inaccuracies in this method would be minimal, and have little effect on the cost analysis.

The company stated that, in this circumstance, the use of this simple cost scaling technique is reasonable to account for the differences in heater sizes. They also conducted further review, and proceeded to make other adjustments in the cost estimate that improve its accuracy. Each change is discussed below. Also, other similarities and differences between the Crude II Heater and the Ultraformer Heater are discussed as these relate to the cost for SCR.

- Heater Size: The original capital cost estimate adjusted the costs assuming that the Ultraformer Heater had a maximum heat input capacity of 824 mmBtu/hr. However, this was a data input error and the value should have been 843.4 mmBtu/hr. The revised/correct value has been used in the attached, revised cost analysis.
- Retrofit Costs: The original cost estimate assumed that the only difference in the capital cost of SCR between the Ultraformer Heater and the Crude II Heater were their heat input capacities (mmBtu/hr). Upon further evaluation, the company stated, and Ohio EPA agrees, that although both heaters are existing heaters and will be retrofitted, the retrofit costs for the Ultraformer Heater are likely more than those needed for retrofitting the Crude II Heater. This is due to the Crude II Heater already undergoing significant upgrades, including new structural components, ductwork and a new stack. Thus, the incremental cost to add SCR to the modified Crude II Heater should be similar to adding SCR to a new heater.

Accordingly, the updated capital cost estimate then subtractsone million dollars from the actual capital costs for SCR on the Ultraformer Heater, before scaling, to deduct the retrofit costs that will likely not occur on the Crude II Heater.

Attached is Exhibit 2, which is an updated Table 5-5 from the original permit application showing a revised summary of the Crude II Heater NOx BACT cost analysis.

The updated analysis continues to show ULNB for this particular heater is appropriate as BACT. The average and incremental costs of both SCR cases are not believed to be economically feasible.

Comment #7: The permit application states on p. 1 that the nominal throughput crude capacitywill not be increased, and p. 1-2 states that the reconstructed Vacuum Furnace(B001) will have roughly the same rated heat input. However, p. 2-8 states that the reconstructed Crude Distillation Unit II Heater (B004) will have aslightlylarger capacity. Please explain the need for increasing the capacity for B004when throughput crudecapacity will remain the same.

Response #7: The crude oil processing capacity of the refinery will not increase (current capacity is 160,000 barrels per day). The reason for needing a higher heat input for B004 is that the new crude oil type is heavier than existing crude oil at the facility and requires a larger amount of heat to vaporize in the Crude Tower. There will be no physical change to existing equipment that brings crude oil into the facility for processing.

Comment #8: The coker cycle time is being decreased from 19 hours to 12 hours, but the permitapplication does not mention what effect this will have on emissions. Pleaseexplain the effect that the decreased cycle time will affect emissions.

Response #8: Emissions calculations included in the permit application take into account the reduction in cycle time of the coker unit from 19 hours to 12 hours. The direct effect is that the number of times the coke drums open will increase. As a result, small amounts of emissions to ambient air occur due to the drums being under slight pressure when opened. However, the emissions are minor due to steaming out each drum, and the drum is cooled significantly and depressured prior to it being opened.

These emissions increases (for VOC, HAP and greenhouse gases) are discussed on page 2-11 of the application, and used emission factors from Table 5-5 ("Average Vent Concentrations and Emission Factors for Delayed Coking Units Vents") from U.S. EPA's Refinery Emissions Protocol document. Potential emissions were based on a maximum 8,760 hours per year of operation with 12 hours per coke cycle. Table A-18 in the permit application contains the calculations and resultant emissions increases.

Lima Refining Company also informed Ohio EPA that an upstream effect of decreasing the coke cycle time to 12 hours is a possible increase to the Coker feed rate, which in turn, increases the firing at the preheat furnace. The company estimated that this would result in an increase to the Coker feed rate and furnace duty by 30 percent above baseline level, and included these increases in Tables A-3 through A-9 of Appendix A in the permit application.

One downstream effect is that the coke product handling increases, and these increases were included in Table A-19 of Appendix A in the permit application.

Comment #9: The permit application states on p. 1-3 that the new and existing sulfur recoveryunits (SRUs) will be equipped to allow oxygen enrichment and that oxygenenrichment is planned for use only as a backup when an SRU fails. However, thedraft permit does not restrict oxygen enrichment to SRU failure incidents. Pleaseexplain why the draft permit does not limit the usage of oxygen enrichment.

Response #9: Design of the SRU automatically uses oxygen enrichment when the feed header pressure or flow is above a specified value. Typically, oxygen enrichment will occur when one of the SRU's trips off and acid gases must be redirected to the other SRUs which are operating. Table A-11 in the permit application shows the maximum emissions for operating in both modes – with and without oxygen enrichment. As a conservative approach, the company requested permit limits based on the higher emissions assuming use of oxygen enrichment. Thus, there is no need to establish an operational restriction limiting the use of oxygen enrichment. 40 CFR, Part 60, Subpart Ja allows slightly higher sulfur dioxide (SO2) emissions from the SRU incinerator stack when using oxygen enrichment, however, the permit will require compliance with the 250 parts per million SO2 limit, on a 12-hour average basis, regardless of whether oxygen enrichment is being used.

Comment #10: The permit application states on p. 4-33 that Linde Corporation, which will supplyLRC with steam, hydrogen and oxygen, is not considered part of LRC. Linde isadjacent to the refinery but not owned or controlled by Husky LRC. Linde hascustomers besides LRC.

Please provide us an estimate of how much of Linde'sproducts go to LRC or other facilities owned or operated by LRC or Husky andhow much Linde's emissions will increase as a result of LRC's Crude OilFlexibility project.

Response #10: Immediately upon receipt of the application Ohio EPA made a determination that LRC and the construction and installation of a prospective hydrogen plant which would most likely be owned and operated by Linde Corporation ("Linde") would not constitute a single stationary source for purposes of new source review permitting. OAC rule 3745-31-01(RRRRR) contains the following definition:

"Stationary source" means all of the emissions units that belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel and those emissions resulting directly from an internal combustion engine for transportation purposes or from a non-road engine or non-road vehicle as defined in Section 216 of the Clean Air Act. Emissions units shall be considered as part of the same industrial grouping if they belong to the same major group (i.e., that have the same two-digit code) as described in the "Standard Industrial Classification Manual."

LRC and Linde Corporation do not have the same two-digit Standard Industrial Classification (SIC) code and do not involve common control. LRC has SIC code 2911 for petroleum refining and Linde has SIC code 2813 for Industrial gases. The only connection between LRC and Linde is the contract between the two entities which is a supply/service contract, not a contract providing any ownership interest. Location on contiguous or adjacent properties is the only single stationary source criteria that has been met and as such examination of the interrelatedness regarding the amount of product provided by Linde is not necessary for this evaluation.

Comment #11: A Leak Detection and Repair program (LDAR) is being required under NSPS, Subpart GGGa for volatile organic compounds. Please include an analysis ofusing LDAR for the control of fugitive methane emissions from equipment leakspertaining to the proposed new piping and emission units ofthe project.

Response #11: The permit application includes a discussion of LDAR for all VOC components. Methane is not a VOC, so normally it would not be subject to regulation. However, since greenhouse gas (GHG) regulations are now in place, methane is regulated as a GHG. New and modified equipment with methane emissions is subject to GHG BACT.

For BACT, the company proposes that their current LDAR program will be updated to include leak detection monitoring for all new and modified piping components in natural gas service (they are already monitoring components in refinery fuel gas service since there are other organic compounds present). The existing LDAR program complies with 40 CFR, Part 60, Subpart GGGa and 40 CFR, Part 63, Subpart CC. Three emissions units in the crude oil flexibility project have planned new or modified natural gas piping: the new SRU 3 unit (P049), reconstructed vacuum unit II heater (B001) and reconstructed/modified crude II heater (B004). A permit term has been added for each of these emissions units that includes the requirement to conduct LDAR fornew or modified natural gas piping components.

Comment #12: The permit application on p. 1-4 and the calculations in Appendix A only accountfor the replacement flare's emissions with regard to the pilot and purging, statingthat "The new and old units will operate under a balanced operation such that the[pressure] swings should not be as severe and the units will be able to betterhandle and treat the gas without flaring. As a result, process upset emissions atthis flare are notanticipated to increase as a result of this project." EPA hasobjected to Title V refinery permits whose flaring emission calculations do notinclude emergency or malfunction situations. *See, In the Matter of BP ProductsNorth America, Inc., Whiting Business Unit,* Petition No. 089-25488-00453(October 16, 2009).Please revise the calculations to include flaring emissionsduring emergencies and malfunctions or provide more detailed justification foromitting such calculations.

Response #12: Ohio EPA concurs with the USEPA, Region V that the permit review needs to consider all emissions that result from the COF project. This should include emissions due to emergencies and malfunctions, if these are affected by the project. With regard to the acid gas flare, the company included increased emissions from routine operation (i.e. larger pilot and sweep gas rates). Likewise, the company evaluated whether the project would result in any increases to non-routine flaring (i.e.: malfunction or emergency events). Historically, the acid gas flare is rarely used and total emissions from upsets and/or malfunctions are relatively modest, typically only resulting from a few of these events per year with total sulfur dioxide emissions of approximately two to five tons per year. Based on a detailed review, the company determined that the COF project was not expected to result in any increases to these emergency/malfunction emissions. Some discussion of this issue was included in the original application, however, a more detailed justification is provided with this document as Exhibit 3.

Besides quantifying the emissions impacts of the project, there are three particular areas of the permit review for which emergency emissions might be considered.
Each is discussed below and in Exhibit 3.

One instance that emergency emissions might be considered in the permit is in the BACT analysis for a project that triggers PSD. The BACT analysis included in the original COF permit application did consider emergency malfunction emissions from the acid gas flare. Likewise, the draft permit included, among other requirements, a BACT work practice standard requiring development and use of a sulfur load shedding plan to minimize the amount and duration of any acid gas flaring during upsets. Regardless, in response to U.S. EPA's comment, the company re-visited the BACT analysis and identified additional work practice standards that will help minimize emissions from flaring. Many of these additional requirements are already required for the acid gas flare through the applicability of NSPS Subpart Ja to the acid gas flare. A revised BACT analysis for the Acid Gas flare (P040) which more fully considers malfunction and emergency flaring is attached as Exhibit 4. These additional BACT work practices are proposed to be included in the final permit.

Another instance for emergency emissions to be considered in a permit review is in the PSD applicability determination. For that purpose, it is important that all emissions increases resulting from the COF project be included. As stated above (and supported by Exhibit 3), the company included increased routine flare emissions in the PSD applicability determination and did not need to include emergency emissions because these would not change as a result of the project. Additionally, it is worth noting that this project triggered PSD for sulfur dioxide (the only significant potential emissions from this flare) regardless of any potential emissions from this emissions source. Thus, any potential emergency emissions from this emissions source have no bearing on this project's PSD applicability determination.

Another area where emergency emissions might be considered in a permit review is as a possible numeric permit limit. However, imposing a numeric permit limit on emergency emissions from this flare is not required as part of this permitting action for the following reasons:

- First, since the project will increase the routine emissions (from pilot and sweep gas combustion), emission limits for the routine emission are included in the draft permit. However, the project will not increase emissions from emergency events (as discussed above and in Exhibit 3). Rather, the project's impact on emergency emissions is to directionally decrease the emissions. Had the company requested taking netting credits for that decrease, an emissions limit would be appropriate to make the decrease creditable. Since no credits were required (in fact PSD was triggered), there is no need to impose a new limit.

- Second, and most important, emissions from such events are not predictable. Besides the pilot and sweep gas combustion, there is <u>zero</u> flaring from normal operating conditions. The acid gas flare at the facility is truly an "emergency" flare in the standard context of that term. Flaring only occurs from startups, shutdowns, malfunctions or upsets. As discussed previously, acid gas flaring events are infrequent and generally result in only modest levels of annual emissions. The frequency and magnitude of such events are impossible to predict – and thus developing an appropriate emissions limit is difficult.

- Finally, rather than establish a numeric limit for emergency emissions, a more appropriate and useful permit requirement related to emergency emissions is the use of work practice standards and reporting requirements. The revised and attached BACT analysis for this flare shows several of these requirements including:

- Develop and implement a sulfur load shedding plan.
- Develop and implement a written flare management plan; and
- Conduct a root cause analysis and a corrective action plan whenever flared sulfur dioxide emissions exceed 500 lbs/day or the flow to the flare exceeds 500,000 standard cubic feet above baseline in any 24-hour period.

For these reasons stated above, the final permit, as amended with the attached updated BACT analysis and expanded justification of the emissions estimates, properly considers emergency and malfunction emissions from the acid gas flare.

Comment #13: The draft permit has carbon dioxide (CO2) as a surrogate for GHG emissionsincluding GHG CO2 BACT limits for several emission units. Even though CO2may make up the majority of the GHG emissions for this proposed project, theregulated pollutant is GHG not CO2. Therefore, the GHG emission limits shouldbe expressed in terms of CO2 equivalent (C02e) so that they account for allGHGs. Please also clarify how compliance with each of the GHG emission limitswill be demonstrated.

Response #13: Lima Refining Company has calculated GHG emissions for all components of the GHG (i.e. – carbon dioxide, methane, nitrous oxides and CO2e), thus it has informed Ohio EPA that is will be able to comply with greenhouse gas emission limits whether the limits are expressed in CO2 or CO2e for rolling, 12-month periods.

Thus, the permit terms have been changed so that all GHG emission limits are established for CO2e, not CO2.

Comment #14: On p. 5-7 of the permit application, flue gas recirculation (FGR) is rejected asBACT due to "operational constraints and the high cost of the additional fan andductwork." Please explain the operational constraints in detail and why theymake FGR technically infeasible. Also, the fan and ductwork cost should beconsidered in the economic feasibility part of the analysis, not the technicalfeasibility part. Please address the cost effectiveness of the fan and ductwork inan economic feasibility analysis that is separate from the technical feasibilityanalysis.

Response #14: The BACT analysis for NOx contained within the application has been revised to address the comments associated with FGR. Please refer to the BACT analysis revisions included with these response to comments.

Comment #15: On p. 5-8 of the permit application, selective non-catalytic reduction (SNCR) isrejected as BACT. The technical feasibility analysis states that "SNCR systems,in some instances, achieve approximately 40% reduction of NOxbut require veryspecific temperature and residence time characteristics of the heater to befeasible." Please explain whether and to what extent the specific temperature andresidence time requirements of SNCR make the technology infeasible. Also, thecomparable emission reduction of other control technologies and the lack ofSNCR on similar sources listed in the RACT/BACT/LAER Clearinghouse are notappropriate reasons to reject SNCR as BACT. Please omit these justifications forSNCR rejection from theanalysis.

Response #15: The BACT analysis for NOx contained within the application has been revised to address the comments associated with SNCR. Please refer to the BACT analysis revisions included with these response to comments.

Comment #16: The only control technology mentioned in the refinery heater SO2 BACT analysison p. 5-14 of the permit application is methyl diethanolamine scrubbers for theremoval of H2S sulfur. Please explain what other control technologies have beenconsidered. Also, there should be a technical feasibility and cost effectiveanalysis specific to LRC for non-H2S sulfur removal technologies. The currentanalysis, rather than providing this, mentions EPA's finding of such technologiesto be prohibitively expensive in its NSPS Subpart Ja Regulatory Impact Analysis.

Response #16: Lima Refining Company revised the SO2 BACT analysis for the Crude II and Vacuum II heaters (emissions units B001 and B004) in response to this comment. Their revised SO2 BACT analysis provided more detail on alternative control technologies, and also provided a site-specific cost estimate for total sulfur, including non-hydrogen sulfide sulfur. A five step, top-down approach was used for the revised analysis, and is “Revised Section 5.2”

Comment #17: The modeling analysis for the new SRU utilizes EPA's policy for intermittentoperating units. The policy, provided in EPA's March 1, 2011 memorandumtitled "Additional Clarification Regarding Application of Appendix W ModelingGuidance for the 1-hour NO2 National Ambient Air Quality Standard," isintended for sources that operate very infrequently, e.g., emergency generators,and are therefore not expected to contribute to the modeled design value. The application ofthe policy to the new SRU appears to result in modeling annualizedactual emissions rather than allowable emissions. Please revise the modelinganalysis so that it does not utilize the policy or provide quantitative operationaldata that justifies application of the policy to the new SRU.

Response #17: U.S. EPA modeling guidance for comparison to short-term ambient air quality standards[1] allows special treatment of emissions sources with infrequent operation (for example - emergency generators, various startups/shutdowns, etc.) since these types of events and their resultant emissions are highly unlikelyto match all other worse case modeling assumptions (operating rates, worse case meteorological conditions, etc.). This guidance also allows special treatment of emissions sources such as annualizing these emissions for short-term modeling, or in some cases, even ignoring them.

[1] EPA's March 1, 2011 memorandum"Additional Clarification Regarding Application of Appendix W ModelingGuidance for the 1-hour NO2 National Ambient Air Quality Standard"

The Air Quality Analysis for the COF project takes into account that the new SRU has infrequent events that emit at levels close to the allowable emissions.This operation is similar to the intermittent sources addressed by U.S. EPA's modeling guidance. Although the new SRU will have continuous operation, and sulfur dioxide emissions that are allowed by NSPS Ja can approach 250 parts per million in the stack, past operating data for existing SRU's at the facility indicates that average actual emissions from SRUs are much less. The company's existing SRU units (Claus 1 and 2) typically average 70 parts per million from the stack. Table 17-1 below shows the most recent stack data with emissions concentrations for the existing SRU units (January 2012 through September 2013).

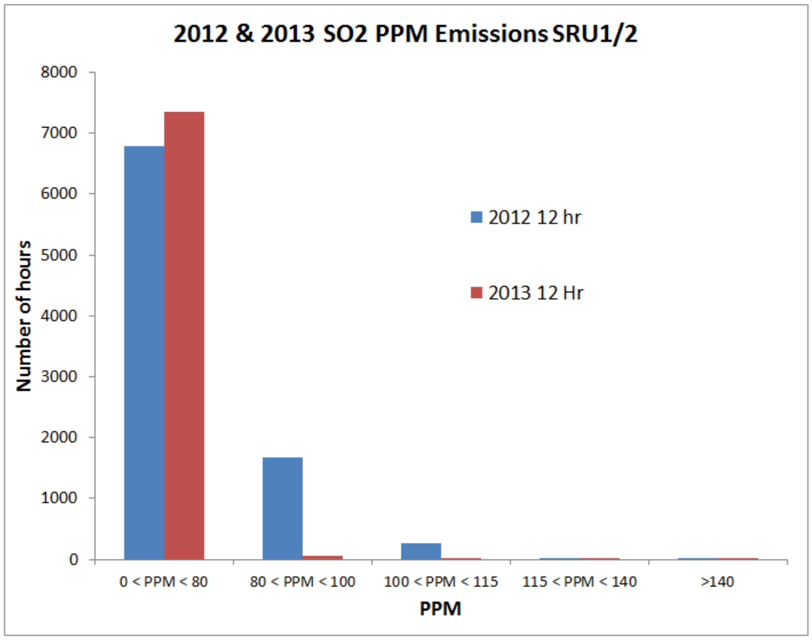
Table 17-1

LRC SRU1/2 Stack SO2 PPM	2012 12 hr avg PPM	2013 YTD 12 hr avg PPM
Annual Average (ppm)	66.5	34.5
Total hours over 115 PPM	36	26
Number of separate events with hours >115 PPM	6	3

The company has stated that concentrations as high as 250 parts per million sulfur dioxide can occur, but those events are rare and are related to process upset conditions. Thus, the new SRU can be considered as if were operating as two types of sources: first - it operates year round at 70 parts per million sulfur dioxide; and second – it has intermittent operation on an infrequent basis, at levels up to 250 parts per million sulfur dioxide.

The data in Table 17-1 shows, that typically, operation is less than ½ percent of the total operating hours when the SRU performance exceeds 115 parts per million sulfur dioxide, for a total of less than 40 hours per year. Table 17-2 below shows the typical distribution of SRU performance data over for the past few years. This table demonstrates the concentration in the existing SRU stack is less than 80 parts per million sulfur dioxide, as a 12-hr average, for the large majority of the operating hours.

Table 17-2



The company conducted short term dispersion modeling of the new SRU (Claus 3)using emissions rates corresponding to the approximate 115 parts per million sulfur dioxidein the stack at maximum process rates. This is virtually double the typical expected concentration for sulfur dioxide under normal operations and, thus, is already a conservative value. Emissions above this level would only occur on an intermittent basis as shown in the historic sulfur dioxide concentration data from the two existing SRUs.

Although U.S. EPA's standard guidelines for air quality modeling in Appendix W recommend use of maximum allowable emissions in most circumstances; these guidelines are not intended to be strict modeling instructions. Instead, case-by-case analysis and professional judgment are frequently allowed to determine the most appropriate data for use in a modeling analysis. As shown in Table 17-2, the company stated that operation of the new SRU Claus 3 emitting at 250 ppm sulfur dioxide continuously is not a realistic emission scenario, and would result in a gross over-estimation of the COF project's actual impacts. Instead, the company stated that use of 115 ppm sulfur dioxide as representative of the worst-case concentration is a conservative and reasonable approach for the modeling analysis.

Comment #18: The modeling for short-term National Ambient Air Quality Standards requiresrepresentative short-term emissions as described in 40 CFR Part 51, AppendixW, Table 8-2. Many of the modeled emission rates appear to be based on longtermaveraged emissions. Representative short-term emissions should be used orfurther explanation and justification of the emissions should be provided.

Response #18: Similar to the response for U.S. EPA comment #17, the modeling approach of the SRU Claus 3 unit was unique, and none of the modeling for the other emissions sources was treated in that manner. U.S. EPA comment #18 does not state which of the emissions sources U.S. EPA may be inquiring about for long-term averaged emissions. The following paragraphs show each of the emission sources for which the company believes this comment mightbe referenced. This response addresses NOx for the two re-constructed heaters and sulfur dioxide emissionsfor several other emission sources. A brief summary is presented in the next two bullet items, followed by a more detailed response:

- **NOx Modeling for B001 and B004:** Upon further review, the company discovered that the NOx modeling for the reconstructed Crude II and Vacuum II unit heaters (emissions units B001 and B004) did use annual emission rates in the 1-hr NOx modeling. However, total project 1-hr NOx modeling impacts were less than 20% of the significance impact level (SIL), and would still be well below the SIL even with maximum short-term emissions as demonstrated in the detailed discussion below. All other short-term modeling for these emissions sources used the maximum short-term emissions increase expected for the COF project.

- **Other SO_2 modeling (Affected Heaters, SRU1/2, and FCCU):** U.S. EPA may have an impression that annual emissions were used for short-term modeling when the short-term modeled rate was close to, or sometimes less than the modeled annual emissions. However, this is not as a result of improperly calculated short-term emissions. Rather, such instances are due to calculation of annual emissions being conservative, or other differences in the calculation basis of short-term versus long-term emissions.

NOx Emissions from B001 and B004

The Crude II heater (B004) and Vacuum II unit heater (B001) will be reconstructed as part of the COF project.

The draft permit for these heaters specifies a NOx BACT limit of 0.03 lb/mmBtu (rolling 365-day average) and short-term NSPS limit of 0.04 lb/mmBtu (rolling 30-day average). Annual emissions from the project from these heaters are calculated correctly using the 0.03 lb NOx/mmBtu emission factor; however, the short-term NOx modeling inadvertently used this same emissions rate. This rate will be correct most of the time, but short-term emissions may be up to 33% higher (0.04/0.03 = 133%).

As originally modeled, maximum impact from the project from all emissions sources for the 1-hr NOx ambient averaging period was shown to be 1.7 $\mu g/m^3$. This value is only 17% of the PSD significant impact level (SIL) of 10 $\mu g/m^3$. Thus, the under-estimation of these two heaters maximum short-term NOx is expected to have only a small impact.

To confirm that the COF project would not exceed the acceptable ambient air impact for NOx, even with the increase, the company modeled the two reconstructed heaters individually to identify the maximum potential ambient air concentration from each heater and then added this to the original modeling impact result to verify that the result was still under the SIL. The detailed approach and results are discussed below.

The same AERMOD model used in the original permit application was run with an emissions rate of 1 lb/hr from each of the reconstructed heaters. Each heater was set up as an individual source group in AERMOD. This identified the maximum unitized impact value (µg/m^{3}per lb/hr of emissions) from each heater. Table 18-1 below provides a summary of the analysis. The original modeled emissions rate in column D from these heaters is shown, along with, the corrected short term emissions rate in column E, using an actual short-term allowable of 0.04 lb NOx /mmBtu. The change in emissions in column F was then multiplied by the model-determined maximum unitized impact value in column G to determine the maximum possible increased impact in column H for these emissions.

The maximum potential increase impact from each heater is summed in column I, and then added to the original modeling result in column J to determine the maximum possible modeling result in column K if the model was run with the revised emissions units B001 and B004 short-term emissions. This revised maximum impact value in column K is still well less than the SIL of 10 mg/m^3 for the one-hour NOx standard. Table 18-1 results are also conservative due to the location of the unitized maximum impact of each of the two heaters may not be at the same location as each other, or at the location of the maximum impact of the other facility emissions sources. The location of the maximum impact was not taken into consideration in this analysis.

Table 18-1

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
	Maximum Design	Original NOx Factor	***Correct NOx factor***	Original Modelled	***Correct Modelled***	***Change in Emissions***	Max. 1 hr impact	***Maximum increased impact***	
	MMBtu/hr	lb/mmbtu	***lb/mmbtu***	lb/hr	***lb/hr***	***lb/hr***	ug/m3 per lb/hr	**µg/m^3**	
B001	102.3	0.03	***0.04***	3.069	***4.092***	***1.023***	0.813	***0.832***	
B004	624	0.03	***0.04***	18.72	***24.96***	***6.24***	0.280	***1.747***	
					Sum of max. possible increase			***2.579***	(I)
					Original Modeling Result			1.654	(J)
					Max. Possible revised modeling			***4.233***	(K)
					Significant Impact Level			**10**	

The data in Table 18-1 confirms that the COF project's 1-hr NOx modeling impact would still be less than the SIL using the revised short-term NOx emissions rate 0.04 lb NOx/mmBtu for emissions units B001 and B004.

<u>SO_2 Emissions from Project Affected Heaters</u>
The COF project is expected to result in increased firing rates of six existing refinery process heaters. The maximum emissions rates of SO_2 from heaters may be variable for short-term (lb/hr) vs. long-term (tons/yr) since NSPS Subpart Ja allows

162 parts per million (ppm) H_2S in refinery fuel gas on a short-term basis (3-hr avg.) compared to 60 ppm H_2S on a long-term (annual average) basis.

For the short-term modeling, the company properly used the short-term allowable H_2S level of 162 ppm to calculate future maximum short-term emissions rate for these heaters. The company accounted for an additional 50 ppm of non-H_2S sulfur in the fuel gas to represent other possible sulfur species not regulated or monitored by NSPS Subpart Ja. This resulted in a total reduced sulfur (TRS) concentration of 212 ppm (162 ppm +50 ppm) used to estimate the maximum short-term emissions rate for the affected heaters. This information is reflected in the post-project emissions rates shown in the permit application emissions calculations, Appendix A (Table A-23 “Basis for Short-Term Emissions Rates use in Modeling”).

However, it is important to note that for SIL modeling of existing un-modified heaters; the modeling is conducted using the “increased” emissions due to the project instead of the future maximum emissions rate. To summarize, the SO_2 emissions rates modeled for the COF project for un-modified heaters were the difference between the future post-project maximum emissions rate and the past actual rate.

For modeling against the short-term (1-hr) standard, the past actual emissions considered were the maximum past actual rate for each heater for each relevant short-term averaging period (1-hr, 3-hr and 24-hr). For example, the 24-hr SO_2 SIL modeling for each emissions source was based on the difference between the future projected emissions (based on 212 ppm TRS) minus the past actual maximum 24-hr average emissions rate based on each heater’s baseline period actual operating data. The past actual firing rates, sulfur levels and resultant emissions used as the basis of the 1-hr, 3-hr and 24-hr SO2 modeling analysis are shown in the permit application, Appendix A, Table A-23 referenced above.

The above described approach results in a conservative estimate of the expected increased short term emissions from each heater due to the COF project. It assumes worst case short-term future emissions (not annualized emissions). Also, results obtained using this method are more conservative than other methods that could be used.

<u>SO_2 Emissions from Existing SRUs – Claus 1 and 2</u>
The existing SRUs are currently operating close to maximum capacity on an annual average basis, and on a short-term basis theseoperate at capacity frequently. As a result, the maximum possible short-term emissions increase for these units is expected to be rather small.

The company calculated the maximum possible short-term emissions increase in a manner similar to the estimation of the modeled rates for increased utilization of the existing heaters previously discussed. Specifically, the increased short-term emissions rate of the existing SRUs was calculated as the difference between the maximum future short-term emissions rate minus the maximum past actual emissions estimated during the baseline period. These short-term emissions were for the 1-hr, 3-hr and 24-hr SO_2 averaging periods being modeled.

Since the existing SRUs are already operating close to capacity, and as such, have SO_2 ppm performance in the stack at or near the maximum regulatory allowable rate of 250 ppm SO_2, the maximum past actual short-term emissions modeled (18.71 lbs SO_2/hr) are almost equal to the unit's allowable emissions rate of 19.18 lbs SO_2/hr). Thus, the project related maximum short-term emissions increase that was modeled from this existing source is relatively small (0.47 lb SO_2/hr).

This value is the maximum short-term increase that could be attributed to the COF project. The company did not use annualized emissions for modeling against the short-term standards.

<u>SO_2 Emissions from Fluid Catalytic Cracking Unit (FCCU)</u>
SO_2 emissions from the FCCU are calculated using the stack flow rate along with SO_2 ppm levels. The short-term emissions rate for SO_2 modeling was based on the maximum allowable Federal Consent Decree level of 25 ppm SO_2 in the stack. Although this is an annual allowable value in ppm, the flow rate used in the short-term emissions calculation was extremely conservative by assuming that the stack flow rate increases from past actual average levels to maximum potential (PTE) levels. Further, stack flow rate increases for the COF project are expected to be much lower due to this project, and readily account for any short-term variability in the stack SO_2 concentration as demonstrated in the following two indented paragraphs. Lower emissions estimates would have resulted if the company would have used an alternative calculation using a maximum SO2 concentration and actual project expected flow rate increases:

Original Calculation: On a potential to emit basis, the flow rate in the FCCU stack was assumed to increase 41 percent above average past actual rates. This increased flow rate (22,305 dscf/m at 0 percent oxygen) and the assumed SO2 concentration in the stack (25 ppm SO_2 at 0 percent oxygen) resulted in an estimated increase emissions rate of 5.65 lbs SO_2/hr; and

Alternative Calculation: On a projected future actual basis, the stack flow is expected to increase no more than 7,362 dscf/m at 0 percent oxygen due to the COF project. Even assuming peak SO_2 concentration levels of 50 ppm SO_2, based on past actual data, this results in a maximum short-term emissions rate of only 4.10 lbs SO_2/hr. This is smaller than the emissions rate actually modeled. Therefore, the modeled value is conservative, even for short-term project impacts.

Comment #19: The modeling analysis does not include an ozone analysis. NOx is a precursor toozone. 40 C.F.R. § 52.21(b)(50)(i). As NOx emissions are above 40 tons peryear, an ozone analysis is required. Ohio Administrative Code 3745-31-16(B).

Response #19: Ozone is a photochemical pollutant normally not emitted directly from emissions sources, but rather, is created through complex reactions involving precursor pollutants such as oxides of nitrogen (NO_x). Assessing the NOx emissions impact from single facilities for ozone formation has historically presented significant challenges.

Ozone formation occurs over tens to hundreds of kilometers downwind from emissions sources and the chemical interactions of ozone and the precursor pollutants are complex. Currently, there is no EPA-approved model for ozone impact assessment for individual sources, although regional models are available.

Even without a modeling demonstration, the companystated that the NOx emissions of 110 tons/yr from the COF project should not have a discernable impact on ozone formation. To confirm this, the following ozone analysis was performed using data from U.S. EPA regional ozone modeling.

U.S. EPA has developed regional models to simulate ozone levels over large areas. These models have been used effectively by state and federal agencies to develop strategies for reducing ozone precursor emissions and to advance attainment of the ozone National Ambient Air Quality Standards (NAAQS). The company has used data from these regional models to understand the relative impacts to ozone levels based on changes to emissions rates of precursors.

In this analysis, when the COF project emissions were compared with the amount of NOx emission reductions realized by the Cross State Air Pollution Rule (CSAPR) and corresponding modeling results for the 8-hour ozone standard, the impacts from the COF project on nearby ozonemonitors were determined to be below detectable levels and should not have an effect on the attainment status of any area.

<u>Ozone Analysis for COF Project using U.S. EPA's CSAPR Modeling</u>

The CSAPR was developed to assist states in meeting the NAAQS. The development of this rule included extensive modeling to determine the emissions reductions necessary in each state to achieve the ozoneNAAQS in the downwind eastern U.S. Although this rule focused on addressing electric generating units (EGUs), the data is informative and shows the relative impact of the precursors on regional ozone levels.

The regional model, Comprehensive Air Quality Model with extensions (CAMx), and the Air Quality Assessment Tool (AQAT) were used during CSAPR development to determine levels of reduction from EGUs necessary to achieve compliance with the ozone NAAQS. The documentation from the rule development includes extensive tables showing impacts at all ozone monitors in the eastern U.S. and emission reduction levels necessary to achieve those results.

To examine the possible impact of the COF project, the company used the U.S. EPA modeling conducted to establish the final 2014 budgets in CSAPR as found on the website http://www.epa.gov/crossstaterule/techinfo.html. Information regarding the NO_x emission reductions necessary to achieve the modeled design values can be found in the EmissionsSummaries.xlsx" spreadsheet under the <u>Emissions Inventory Final Rule TSD</u> section at the same website. The spreadsheet shows the base case annual NO_x emissions for Ohio in 2014 at 522,450 tons NOx and remedy control scenario annual NO_x emissions at 508,054 tons NOx. Thus, the total NO_xemission reduction modeled for Ohio to meet the CSAPR goals for 2014 is 14,396 tons NOx.

A review of the surrounding states shows similar significant reductions are necessary. Table 1 below shows the Ohio NOx emissions scenarios modeled for 2014 for CSAPR.

Table 1 CSAPR Modeled Ohio NOx Emissions

State	NOx TPY 2014 Base	NOx tpy 2014 Remedy	2014 Remedy minus 2014 Base	
			Difference	% Difference
Ohio	522,450	508,054	-14,396	-2.8%

The company's COF project NOx emissions increases are expected to be 110 tons per year. This is an emissions increase less than 1% of the CSAPR modeled Ohio emissions change. As a result, the COF project ozone impacts would be expected to be proportionally smaller than the CSAPR ozone impacts (discussed next).

8-Hour Ozone Modeling Results
The nearest ozone monitor to the Lima Refining Company is the Allen County monitor located in Bath Township northeast of the City of Lima, Ohio. This monitor is representative of the current ozone levels in this part of Ohio. In the CSAPR analysis, the maximum 8-hour ozone modeled concentration for Allen County is 70.4 parts per billion (ppb) for the 2014 base case and 70.2 ppb for the 2014 remedy scenario as shown in Table 2.

Table 2 CSAPR Ozone modeled impacts for Allen County, Ohio

8-Hour Ozone (ppb)					
Monitor ID	State	County	2014 Base Case Maximum Values	2014 Remedy Maximum Values	Max. Decrease
390030009	Ohio	Allen	70.4	70.2	0.2

Note: Data from EPA's CSAPR website in a spreadsheet called "CSAPR_Ozone and PM2.5_Design Values.xlsx". This spreadsheet shows the projected base case 2014 ozoneconcentrations at surrounding monitoring sites versus control strategy (remedy) ozoneconcentrations.

The 2014 CSAPR modeling shows an ozone reduction of 0.2 ppb in Allen County as a result of NO_x emission reductions from CSAPR. In order for this modeled annual concentration reduction from CSAPR to occur, Ohio's 2014 NO_x emissions were reduced by 14,396 tons of NO_x. The company has used this information to assess the impact of the significantly smaller COF project emissions changes.[2]

[2]This analysis is conservative because it assumes that 100% of the CSAPR modeled change to Ohio ozone levels are caused by Ohio emissions reductions. In reality, although some of the Ohio emissions reductions may be at locations that would have minimal impact on the Allen County ozone monitor; this is more than offset by the tens of thousands of tons of NOx reductions for upwind states (e.g. Indiana, Illinois, Missouri, Iowa, etc.) included in the CSAPR modeling (but ignored here) which will impact the Allen County monitor.

To estimate the impact of the COF project NOx emissions change to modeled concentrations, the CSAPR modeled NOx change (ppb) was multiplied by the ratio of the COF project NOx emissions increase (tpy) to the CSAPR 2014 NO_x emission reductions (tpy). This provides an indication of the relative impact of the COF project as shown below:

*COF project ozone impact (ppb) = CSAPR Ozone impact (0.2 ppb) * [COF NOx increase (110 TPY) / CSAPR NOx decrease (14,396 TPY)]:*

0.2 * 110 / 14,395 = 0.0015 ppb ozone due to COF project
The predicted COF project ozone impact (0.0015 ppb) is only 0.002% of the current ozone 8-hour NAAQS (75 ppb), and is less than the minimum detection level for typical ozone monitors. This impact would not be measurable and would not cause or significantly contribute to a NAAQS violation.

Comment #20: The analysis modeled negative emissions of NO2. Because the NO-to-N02conversion approaches are screening techniques, they tend to overestimate theeffects of negative emissions. An alternative approach may be available given thesimilarity of the before-and-after source characterizations. Please contact RandyRobinson for information on possible alternative approaches.

Response #20: No alternative modeling is necessary since the project NOx modeling results, shown below in Table 7.4-2 from the original permit application were well below the Prevention of Significant Deterioration SIL levels. The original values used the default ratio of 0.8 for NO-NO_2, which is applied after the modeling. Even without this 20 percent deduction, results would still be well below the SIL.

The “negative” emissions in the modeling analysis are associated with emissions sources for each of the two reconstructed heaters (Crude II and Vac II Unit heaters, emissions units B001 and B004) since the stack locations will change due to the COF project. The post project new total future emissions were modeled as positive emissions from the new stacks and the old past actual emissions were modeled as negative emissions from the old stacks.

Table 7.4-2

NO_2 Project Modeling Impacts Compared with PSD Significant Impact Levels and Monitoring Concentrations

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$)	Class II Significant Impact Level (SIL) ($\mu g/m^3$)	Significant Monitoring Concentration SMC) ($\mu g/m^3$)
NO_2	1 hour	1.7	10	NA
	Annual	0.01	1	14

Comment #21: Page 12 of the draft permit states that emission unit P040, the existing SRUs undergoing modification, is subject to NSPS Subpart J. Please determine whether P040 is also subject to Subpart Ja and either include Subpart Ja as an applicable requirement in the permit or explain why P040 is not subject to Subpart Ja.

Response #21: Emissions unit P040 is also subject to 40 CFR, Part 60, Subpart Ja and the permit has been updated [in section 6.b)(1)h.] to include this applicable regulation.

Exhibit 1 – Revised BACT Analysis from URS

Revised Section 5.1

The following BACT analysis replaces the original NOx BACT section 5.1 of the COF Permit Application.

5.1 BACT for NO_X from Crude Distillation Unit (CDU) II Heater

Step 1 – Identify All Control Technologies

Nitrogen oxides (NO_X) are formed during the combustion of fuel in the heater and are generally classified as either thermal NO_X or fuel-related NO_X. Thermal NO_X results when atmospheric nitrogen is oxidized at high temperatures to yield NO, NO_2 and other oxides of nitrogen. Fuel-related NO_X is formed from the chemically bound nitrogen in the fuel. For natural gas or refinery fuel gas combustion, thermal NO_X formation is the dominant mechanism since there is little or no nitrogen bound in the fuel.

The rate of formation of thermal NO_X is a function of residence time and free oxygen, and is exponential with peak flame temperature. "Front-end" NO_X control techniques are aimed at controlling one or more of these variables. The most efficient front-end combustion controls for heaters include low NO_X burners. "Add-on" controls attempt to chemically reduce the NO_X emissions after they are created through catalytic or non-catalytic techniques.

In order to identify possible NO_X control technologies and resulting emission rates, a review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) was conducted. The RBLC search showed several entries within the past ten years for similar refinery-fuel gas fired heaters. Table 5-1.1, Database Survey -- Available NO_X Control Technologies, summarizes the information found. The data search results were filtered to leave only BACT determinations on refinery-fuel gas heaters and boilers, and to show only those with lb/MMBtu limits to allow for comparison.

For heaters and boilers with a heat input capacity greater than 100 MMBtu/hr, there are examples of Ultra Low NO_X Burners (ULNB), Flue Gas Recirculation (FGR) and Selective Catalytic Reduction (SCR). BACT determinations range from a low of 0.0125 lb/MMBtu (w/SCR) to 0.4 lb NO_X/MMBtu (w/Low-NOx Burners).

Table 5-1.1

Snapshot of Database Survey Results – NO_x Emission Controls for RFG-fired Heaters

Unit	Company	Capacity	Emission Limit	Control Method	State	Basis	Permit No. Date
Vac Heater	Valero Delaware City Refinery	240 MMBtu/hr	0.04 lb/MMBtu (3-hr rolling avg)	SCR	DE	RACT	AQM-003/00016 2/26/2010
Crude Heater		456 MMBtu/hr	0.04 lb/MMBtu (3-hr rolling avg)	SCR		RACT	
Boiler 1 at Delaware City Power Plant		618 MMBtu/hr	0.015 lb/MMBtu (24-hr rolling avg)	SCR with modifications to burners, overfire-air, installation of induced flue gas recirculation and other improvements		BACT-PSD	
Boiler 3 at Delaware City Power Plant		618 MMBtu/hr	0.015 lb/MMBtu (24-hr rolling avg)				
Boiler No. 1	Marathon Petroleum Co. LLC Garyville Refinery	525 MMBtu/hr	0.4 lb/MMBtu (annual avg)	Ultra Low NO_x Burners (ULNB) and Flue Gas Recirculation (FGR)	LA	BACT-PSD	PSD-LA-719 12/27/2006
A&B Crude Heaters, Coker Heater		368 to 480 MMBtu/hr	0.0125 lb/MMBtu (annual avg)	Ultra Low NO_x Burners and SCR (Voluntary)			
Multiple Refinery Heaters		74-540 MMBtu/hr	0.03 lb/MMBtu (annual avg)	Ultra Low NO_x Burners without air preheat			
Three Boilers	Valero Refining LLC, St. Charles Refinery	715 MMBtu/hr each (3)	0.04 lb/MMBtu	Ultra Low NO_x Burners with air preheat	LA	BACT-PSD	PSD LA-619 (M5) 11/17/2009
Refinery Heater		644 MMBtu/hr	0.08 lb/MMBtu (three 1-hr test avg)	Low NO_x Burners			
Multiple Refinery Heaters		86-135 MMBtu/hr	0.03 to 0.04 lb/MMBtu (three one-hour test avg)	Ultra Low NO_x Burners			

Table 5-1.1

Snapshot of Database Survey Results – NO_X Emission Controls for RFG-fired Heaters

Unit	Company	Capacity	Emission Limit	Control Method	State	Basis	Permit No. Date
Process Heater	ConocoPhillips Co, Alliance Refinery	138 MMBtu/hr	0.04 lb/MMBtu (annual avg)	ULNB and internal Flue Gas Recirculation (FGR)	LA	BACT-PSD	PSD-LA-696(M1) 7/21/2009
Process Heater	Chevron Products Co, Pascagoula Refinery	160 MMBtu/hr	0.03 lb/MMBtu (annual avg)	Ultra Low NO_x Burners	MS	BACT-PSD	1280-00058 5/8/2007
Unit 40 Boiler	Conoco-Phillips Borger Refinery	598 MMBtu/hr	0.02 lb/MMBtu (3-hr avg)	Low NO_x Burners with 35% FGR or Fuel Dilution	TX	BACT-PSD	9868A 12/20/2006

Although not identified in this RBLC search results, selective non-catalytic reduction (SNCR) has also been considered in this BACT analysis. Therefore, the following potential NO_X control technology options are evaluated in this BACT analysis:

- Low NO_X (or ultra-low NO_X) Burners;
- Flue Gas Recirculation
- Selective Catalytic Reduction (SCR); and
- Selective Non-Catalytic Reduction (SNCR).

A description of each technology and its potential application to the new heaters is included in the following section.

Step 2 – Eliminate Technically Infeasible Options

Combustion Controls (Low NO_X burners) - Combustion modifications, such as low-NO_X burners reduce the concentration of NO_X emissions in the heater exhaust gas by decreasing combustion temperature or decreasing the quantity of oxygen available for combustion. The most commonly used burner in process heaters is the direct flame type, where combustion is performed in the open space within the heater's firebox. Typical low NO_X combustors achieve 0.04 to 0.07 lb NO_X/MMBtu on an annual average basis. More advanced "next generation ultra-low NO_X burners" can, in some circumstances, be designed to achieve as low as 0.02 lb NO_X/MMBtu on an annual average basis on some types of fuels and heaters.

The ultimate performance of advanced low-NO_X burners depends on the exact composition of gaseous fuel and the configuration and operating conditions of the specific heater. Although some PSD BACT entries in the RBLC database for heaters show predicted annual emissions performance of 0.03 lb NO_X/MMBtu. In the proposed heater service, and with Husky refinery fuel gas, Husky estimates that the lowest consistently achievable emissions rate with ultra-low NO_X burners is 0.04 lb NO_X/MMBtu fuel input on a short term maximum basis, which is the level required by NSPS Ja. However, on a longer term basis (e.g. – annual), these burners are expected to average 0.03 lbs/MMBtu NOx. The use of next generation ultra-low NO_X burner technology is a feasible option and is carried forward to Step 3 in the BACT analysis.

FGR - Flue gas recirculation (FGR) is a combustion control technology used to reduce NOx, typically on large utility boilers. FGR involves the recycling of flue gas into the fuel-air mixture at the burner to help cool the burner flame. (Note: Internal FGR is a feature in some low NO_X burners in which hot O_2-depleted flue gas from inside the heater is drawn into the combustion zone using burner design features. This feature, internal FGR, is considered under Combustion Controls/Low NOx burners, above.) External FGR requires the use of hot-side fans and ductwork to route a portion of the flue gas in the stack back to the burner windbox. External FGR is typically not considered a stand-alone NO_X technique.

Additionally, external FGR has had limited success with process heaters, mainly due to operational constraints. It has had limited success with process heaters and is expected to be less effective than the ULNB proposed. For these reasons, "external" FGR is considered a technically inferior control technology and is not carried forward as a NO_X control option. "Internal" FGR, incorporated into ULNB is already, separately, included in the analysis.

Selective Catalytic Reduction (SCR) – Selective catalytic reduction (SCR) systems involve the post-combustion removal of NO_X from flue gas with a catalytic reactor. Depending on the NO_X inlet concentration, SCR can reduce NO_X 80% or more and achieve levels, in some cases, as low as approximately 4 ppm NO_X (~0.004 lb NO_X/MMBtu). SCR systems selectively reduce NO_X by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. NO_X, ammonia, and oxygen react on the surface of the catalyst to form molecular nitrogen (N_2) and water. The primary chemical reactions are shown here.

$$4NO + 4NH_3 + O_2 => 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 => 3N_2 + 6H_2O$$

A SCR system is relatively expensive to build and operate and is composed of an ammonia storage tank, an injection grid consisting of a system of nozzles that spray ammonia into the exhaust gas ductwork, a SCR reactor, which contains the catalyst, instrumentation and electronic controls.

The heater exhaust gas must contain a minimum amount of oxygen and be within a particular temperature range in order for the selective catalytic reduction system to operate properly. The typical temperature range for base-metal catalysts is 600°F to 800°F. Keeping the exhaust gas temperature within this range is important. If it drops below 600°F, the reaction efficiency becomes too low and increased amounts of NO_X and ammonia will be released out the stack. If the reaction temperature gets too high, the catalyst is not as effective and the ammonia begins to decompose. The use of SCR is technically feasible and is carried forward to Step 3 in the BACT analysis.

Selective Non-Catalytic Reduction (SNCR) - Selective non-catalytic reduction (SNCR) systems are similar to SCR, except no catalyst is used. SNCR may use urea, aqueous ammonia, or anhydrous ammonia, which is usually vaporized and mixed with the hot flue gases from the combustion device. SNCR systems, in some instances, achieve approximately 40% reduction of NO_X but require very specific temperature and residence time characteristics of the heater to be feasible. Also, the effectiveness of SNCR decreases significantly in applications where the NO_X is already low. For this reason, SNCR is most commonly used in applications where the uncontrolled NO_X typically ranges from 200 ppm – 600 ppm. The base NO_X performance of the proposed burners is substantially lower (<40 ppm) than the level typically controlled by SNCR. To our knowledge, SNCR with combustion controls has never been used on a process heater.

Since SNCR achieves less emissions reductions than achieved with use of the proposed ultra-low NO_X burners, SNCR, if even feasible, is considered technically inferior and is not evaluated further in Step 3.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

From Step 2, there are two control technologies that are considered technically feasible, ultra-low NO_X burners and SCR. These available technologies, used separately or together, are ranked in order of effectiveness as shown in Table 5-1.2.

Table 5-1.2
BACT Control Hierarchy for NO_X

(Original BACT Table 5-3 Revised)		
BACT Control Hierarchy for NOx		
	Emission Level used in Analysis	
Technology	approx. ppmv	lb/MMBtu
SCR + ULNB	4	0.004
SCR (w/o ULNB)	5.3	0.0053
ULNB	30	0.03
Baseline (existing uncontrolled heater performance)	40	0.04

Step 4 - Evaluate Most Effective Controls and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each feasible control technology.

Costs: A cost estimate was generated for the CDU II Heater (624 MMBtu/hr) for each of the control options for this specific heater. Tables 5-1.4 through 5.1.6 presented at the end of this section show the basis of each of these capital and operating cost estimates. (Note: Updates to the cost methodology suggested by US EPA in their comment letter regarding the draft permit are highlighted with shading in the attached tables.) Table 5-1.3 summarizes the cost-effectiveness comparison of each of the control options.

Table 5-1.3

Summary of Top-down BACT Impact Analysis for NOx Controls

Emissions Unit	Control Alternative	NOx Emissions (tpy)	Emissions Reduction vs Baseline (tpy)	Total Insalled Capital Cost ($)	Total Annualized Cost ($/yr)	Average Cost Effectivness ($/ton vs Baseline)	Incremental Cost Effectiveness ($/ton vs Proposed ULNB)
Crude II Heater (B004) 624 MMBtu/hr	SCR + ULNB	10.9	98.4	$19,754,340	$1,983,303	$20,157	$27,169
	SCR (w/o ULNB)	14.6	94.7	$19,196,340	$1,906,804	$20,125	$27,502
	ULNB (Proposed)	82.0	27.3	$558,000	$52,675	$1,927	n/a
	Baseline (existing heater performance - regular burners)	109.3					

Other Toxic/Environmental/Energy Impacts: The ammonia used as a reagent in SCR has some direct and indirect negative environmental impacts. Ammonia is very hazardous if accidently released. Consequently, many users of SCR instead use aqueous ammonia (dissolved in water). The use of aqueous ammonia requires extra energy for vaporization of the ammonia. That extra energy creates additional emissions. Also, for maximum SCR effectiveness, some amount of excess ammonia must be added which results in a small amount released out the stack. (This is commonly referred to as ammonia "slip".) This creates emissions of this toxic pollutant that would not otherwise occur. Also, a portion of the ammonia can react with sulfur in the stack forming ammonium sulfate or bisulfate solids, which increase particulate emissions. In many cases, these effects can be reasonably managed and their overall impacts can be small. None of the control options has significant enough toxic or environmental impacts to preclude its use.

Step 5 – Select BACT for NO_X Control

The final step in the top-down analysis process is to select BACT. For this case, the final selection of BACT comes down to a question of the cost-effectiveness of the control options. Cost effectiveness is the economic criterion used to assess the potential for achieving an objective. Cost-effectiveness in a BACT determination is usually measured in terms of annualized cost (dollars) for using the candidate air pollution control device per tons of pollutant emissions removed by the control device each year. While there is no specific published value, a control technology costing approximately $10,000 per ton of pollutant controlled is a common cut-off for cost-effectiveness for NOX. Based on the data presented in Table 5-1.3, neither SCR with ULNB nor SCR without ULNB is considered to be reasonably cost-effective for the CDU II Heater.

The next highest control option, if reasonable, is selected as BACT. Combustion controls utilizing next-generation ultra-low NOx burner technology is the next most effective option. Based on use of Husky internally produced fuel gas, such burners are expected to achieve compliance with NSPS subpart Ja requirement of 0.04 lb NOX/MMBtu (30 day average). Additionally, the burners are expected to achieve 0.03

lb NOx/MMBtu on an annual average basis. This level of control is proposed as BACT for NO_X for the modified CDU II Heater.

Compliance can be demonstrated using the NOx CEM required by NSPS Subpart Ja.

As discussed previously, the VDU II Heater is not technically required to meet BACT for NOx because its NOx emissions will not increase. However, it is noteworthy that Husky is proposing the same type of next-generation ultra-low NOx burners with the same proposed performance for the VDU II heater as is being proposed for the CDU II Heater.

Table 5-1.4 Crude Heater SCR +ULNB Cost-Effectiveness

Husky COF Project Cost Effectiveness Analysis for SCR

SCR System + ULNB for NOx removal			
Unit Characteristics			Crude II Heater
Heater Firing Rate	MMBtu/hr	=	624
H	= annual operating hours	=	8,760
Nox Performance without SCR	Upper bound of existing operations (lb/MMBtu)		0.0400
NOx Performance with SCR	SCR with ULNB		0.0040
Catalyst Cost for one charge	URS Estimate		180,000
NO_x removal by SCR control	= tpy NO_x	=	98.39
N (Ammonia requirement, ton/yr)	= (tpy NO_x removed) (MW NH_3, 17/ MW NO_x, 46)	=	36.36
Costs			
A. Total capital investment, $	Estimated Cost for ULNBs ($9K each, approx. 62 burners)	=	$558,000
	Estimated SCR Cost = Actual Husky TCI forSCR on similar size UF Reformer furnace, cost adjusted for Crude heater differences.	=	$19,196,340
	Total Capital Investment		**$19,754,340**
B. Direct Annual Costs, $/yr			
1. Operating labor	Revised per EPA comment. $0 per OAQPS	=	$0
2. Supervisory labor	Revised per EPA comment. = (0.15) x (operating labor)	=	$0
3. Maintenance labor and materials	= (0.015 * TCI)	=	$8,370
4. Catalyst replacement	Revised per EPA comment. = Cost x FWF (OAQPS Eq 2.52); 7% x [1/(1 + 7%)^5 years -1)]	=	$31,300
5. Catalyst disposal		=	$0
6. Ammonia (anhydrous)	= (N) x ($425/ ton)	=	$15,454
7. Electrical	Revised from natural gas estimate to CCM electrical. Power * Cost elect * t op; Eq 2.49 CCM (from "electrical CCM worksheet")	=	$80,361
TOTAL DIRECT COSTS			**$135,485**
C. Indirect Annual Costs, $/yr			
1. Overhead	Revised per EPA comment.	=	$0
2. Property Taxes, insurance, admin.	Revised per EPA comment.	=	$0
3. Capital recovery	Revised per EPA comment. = (0.0944) x [total capital investment - catalyst replacement cost)]; OAQPS Eq 2.52: 7% x [1/(1 + 7%)^20 years -1)]	=	$1,847,818
TOTAL INDIRECT COSTS			**$1,847,818**
Total Annual cost	**= (Direct Annual Costs) + (Indirect Annual Costs)**	=	**$1,983,303**
Cost Effectiveness			
NOx Emissions from Unit without SCR	= tpy NOx	=	109.3
NOx Removal from SCR	= tpy NOx, 90% of uncontrolled	=	98.4
Cost Effectiveness	***$/tons NOx***	=	***$20,157***

- The capital recovery factors assumes a 20 year equipment life, catalyst replaced every 5 yrs, and 7% interest.

Electricity Costs based on Eq. 2.48 and 2.49 of EPA CCM and assuming $0.07/kWh and 4inch pressure drop in Catalyst + Ductwork.

Table 5-1.4 Crude Heater SCR Capital Cost Estimate

Cost Estimate for Capital Costs of SCR on the Crude II Heater (B004)

Actual TCI Cost of SCR on slightly larger heater (Ultraformer Heater)	
	$24,000,000
Portion of cost that was associated with retrofit installation.	
	$1,000,000
Total cost excluding retrofit	**$23,000,000**
Ultraformer Heater Size	843.4 mmbtu/hr
=	
Modified Crude Heater Size	**624 mmbtu/hr**
Estimated costs using Ultraformer as basis and scaled using six-tenths rule.	
	$19,196,340

Reference:
Six-tenths rule scaling factor

$$\text{Cost}(Q) = \text{Cost}(Q_0) * (Q/Q_0)^n$$

Such that:

Cost (Q) = construction cost, $million
Q = design flow, mmbtu/hr
Q_0 = base design flow based on another reference
n = emperical scaling factor (assumed to be 0.6)

LRC used the six-tenths factor equipment cost scaling technique to estimate the cost of adding SCR to the reconstructed Crude II Heater because detailed actual installation costs were available from the recent installation of SCR at LRC on a heater which is similar in size and configuration to the CCrude II Heater. Basing the SCR cost estimate on actual costs from controlling a similar heater at the same facility is more accurate than any other available technique. Since the Crude II Heater is about 25% smaller than the Ultraformer Heater for which the actual SCR costs are available, it is expected that the costs for SCR for the smaller heater would we somewhat less than SCR for the larger heater, all else equal. Since there is not a large difference in the heaters sizes, this scaling factor does not result in a large adjustment to the costs, and any inaccuracies in this technique would have minimal effects on the cost analysis.

Note: The capital cost estimate has been revised from the original estiamte based on the following two issues.

• Heater Size: The original capital cost estimate had adjusted the costs assuming that the Ultraformer heater was 824 MMBtu/hr. However, this was a data input error and the value should have been 843.4 MMBtu/hr. The revised/correct value has been used in this revised cost analysis.
• Retrofit Costs: The original cost estimate assumed that the only difference in the capital cost of SCR between the Ultraformer Heater and the Crude II Heater were their sizes (MMBtu/hr). Upon further evaluation, we recognized that although both heaters are existing heaters and will be retrofitted, the retrofit costs for the Ultraformer heater are likely larger than those needed for retrofitting the Crude II Heater. This is because the Crude II Heater will already be undergoing significant upgrades, including new structural components, ductwork and a new stack. In this respect, the incremental cost to add SCR to the modified Crude II heater should be similar to adding SCR to a new heater. Accordingly, the updated capital cost estimated subtracted $1 million dollars from the actual capital costs for SCR on the Ultraformer heater, before scaling, to deduct the retrofit costs that will likely not occur on the Crude II Heater.

Additionally, it should be noted that adding SCR to the Crude II heater could be problematic due to lack of available spacing for this extra control equipment. Even if possible, there would likely be additional costs due to spacing issues. However, for the purposes of this analysis, no additional costs have been added.

Table 5-1.5 Crude Heater SCR w/o ULNB Total Costs

Husky COF Project Cost Effectiveness Analysis for SCR

SCR System w/o ULNB for NOx removal			
Unit Characteristics			Crude II Heater
Heater Firing Rate	MMBtu/hr	=	624
H	= annual operating hours	=	8,760
Nox Performance without SCR	Upper bound of existing operations (lb/MMBtu)		0.040
NOx Performance with SCR	SCR without ULNB		0.0053
Catalyst Cost for one charge	URS Estimate		180,000
NO_x removal by SCR control	= tpy NO_x	=	0.00
N (Ammonia requirement, ton/yr)	= (tpy NO_x removed) (MW NH_3, 17/ MW NO_x, 46)	=	0.00
Costs			
A. Total capital investment, $			
	Estimated SCR Cost = Actual Husky TCI forSCR on similar size UF Reformer furnace, cost adjusted for Crude heater differences.	=	$19,196,340
	Total Capital Investment		**$19,196,340**
B. Direct Annual Costs, $/yr			
1. Operating labor	Revised per EPA comment. $0 per OAQPS	=	$0
2. Supervisory labor	Revised per EPA comment. = (0.15) x (operating labor)	=	$0
3. Maintenance labor and materials	= (0.015 * TCI)	=	$0
4. Catalyst replacement	Revised per EPA comment. = Cost x FWF (OAQPS Eq 2.52); 7% x [1/(1 + 7%)^5 years -1)]	=	$31,300
5. Catalyst disposal		=	$0
6. Ammonia (anhydrous)	= (N) x ($425/ ton)	=	$0
7. Electrical	Revised from natural gas estimate to CCM electrical. Power * Cost elect * t op; Eq 2.49 CCM (from "electrical CCM worksheet")	=	$80,361
TOTAL DIRECT COSTS			**$111,661**
C. Indirect Annual Costs, $/yr			
1. Overhead	Revised per EPA comment.	=	$0
2. Property Taxes, insurance, admin.	Revised per EPA comment.	=	$0
3. Capital recovery	Revised per EPA comment. = (0.0944) x [total capital investment - catalyst replacement cost)]; OAQPS Eq 2.52: 7% x [1/(1 + 7%)^20 years -1)]	=	$1,795,142
TOTAL INDIRECT COSTS			**$1,795,142**
Total Annual cost	**= (Direct Annual Costs) + (Indirect Annual Costs)**	**=**	**$1,906,804**

- The capital recovery factors assumes a 20 year equipment life, catalyst replaced every 5 yrs, and 7% interest.

Electricity Costs based on Eq. 2.48 and 2.49 of EPA CCM and assuming $0.07/kWh and 4inch pressure drop in Catalyst + Ductwork.

Table 5-1.6 Crude Heater SCR w/o ULNB Total Costs

Husky COF Project Cost Effectiveness Analysis for ULNB

ULNB only for NOx removal

Unit Characteristics			Crude II Heater
Heater Firing Rate	MMBtu/hr	=	624
H	= annual operating hours	=	8,760
NOx Performance without ULNB	Upper bound of existing operations (lb/MMBtu)		0.0400
NOx Performance with ULNB	ULNB performance, lb NOx/ MMBtu annual average		0.0300
Costs		=	
A. Total capital investment, $	Estimated Cost for ULNBs ($9K each, approx. 62 burners)	=	$558,000
B. Direct Annual Costs, $/yr			
1. Assume no additional operating Costs for ULNB		=	$0
TOTAL DIRECT COSTS			**$0**
C. Indirect Annual Costs, $/yr			
3. Capital recovery	(0.0944) x [total capital investment]; OAQPS Eq 2.52: 7% x [1/(1 + 7%)^20 years -1)]	=	$52,675
TOTAL INDIRECT COSTS			**$52,675**
Total Annual cost	**= (Direct Annual Costs) + (Indirect Annual Costs)**	**=**	**$52,675**

- The capital recovery factors assumes a 20 year equipment life, catalyst replaced every 5 yrs, and 7% interest.

Revised Section 5.2

The following BACT analysis replaces the original SO_2 BACT section 5.2 of the COF Permit Application.

5.2 BACT for SO_2 from Refinery Heaters

SO_2 is generated when sulfur-bearing fuels such as refinery fuel gas are combusted, and the H2S and other sulfur species (such as COS and mercaptans) are oxidized to SO_2.

Step 1 – Identify All Control Technologies

Emission control technology for refinery gas is primarily treatment of the refinery fuel gas to remove H_2S prior to the gas being combusted. H_2S is the major sulfur species in refinery fuel gas. Amine-based gas cleanup is a reduction type scrubbing process, commonly used for "gas sweetening" processes in refinery fuel gas or tail gas treatment settings where H_2S in the process gas may be treated before use as a fuel or release to the atmosphere. There are a few different amine-based technologies (with slightly different amine/chemical solutions) however, all use the same basic principles and achieve comparable levels of sulfur removal.

In addition to sulfur in the form of H_2S, refinery fuel gas contains a lesser amount non-H_2S species of sulfur, principally mercaptans (e.g.; ethyl mercaptan, C_2H_5SH). Amine-based solvents typically do not remove these other sulfur species as effectively as they treat H_2S. The level of other sulfur species is assumed to be equal to approximately 50 ppm at LRC. In order to lower the fuel gas content of non-H2S sulfur, additional fuel treatment would be required. Technologies that are expected to be effective for mercaptan removal include some combination of a caustic wash tower, Merox caustic wash tower, and or a sponge oil absorber.

Rather than treating the fuel to remove sulfur before combustion, in some situations, SO_2 can be scrubbed from the exhaust stack gases. Flue Gas Desulfurization (FGD) is an established technology for SO_2 removal from the exhaust of coal-fired boilers.

In order to identify other possible SO_2 control technologies and resulting emission rates, a review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) was conducted. The RBLC search showed several entries for refinery-fuel gas fired heaters. BACT levels identified in the database ranged from a low of 25 ppm H_2S annual average to 218 ppm average total sulfur. The variation is due to site specific situations. Multiple determinations indicated BACT as compliance with NSPS Ja (i.e.: 60 ppm H_2S annual average in the fuel gas or 8 ppm SO_2 in the stack). The RBLC does not explicitly list the fuel gas treating technology used by the permitted sources. However, based on our industry experience, virtually all refineries use an amine-based solvent scrubbing fuel gas treatment system, such as MDEA, to remove H_2S from the fuel gas.

Table 5-2.1 RBLC for Refinery Heaters and Boilers SO2 Emissions

RBLC ID	Basis	Date	State	Facility	Process Description	Emission Limit
WY-0071	BACT	10/15/2012	WY	Sinclair Wyoming Refining Co. Sinclair Refinery	Heaters: 50 to 233 MMBtu/hr	(60 ppmvd annual average 162 3-hour average - H2S)
LA-0213	BACT	11/17/2009	LA	Valero Refining - New Orleans, LLC St. Charles Refinery	Heaters/Boilers (various sizes)	Use of NG or RFG with H2S < 100 ppmv (annual average)
LA-0234	BACT	1/26/2009	LA	Citgo Petroleum Company Lake Charles Complex - Cat Gas Hydro	Reboiler/Furnace (various sizes)	218.4 ppm average; 475 ppm max sulfur conc.
LA-0211	BACT	12/27/2006	LA	Marathon Petroleum Co LLC Garyville Refinery	Heater 155.2 MMBtu/hr	25 ppmv as H2S annual average
OH-0329	N/A	8/7/2009	OH	BP Products, North America, Inc. BP-Husky Refining LLC	519 MMBtu/hr Reformer Heater	8 ppmvd (SO2) @ 0% O2, 365-day rolling avg. 20 ppmvd (SO2) @ 0% O2, 3-hr rolling avg.
TX-0539	BACT	7/22/2009	TX	Total Refining - Port Arthur Total Port Arthur - SRU and Crude Handling	Coker Unit Heaters 211 MMBtu/hr	75 ppmv H2S annual average

Based on our knowledge of refinery systems, the RBLC, US EPA rulemaking, and other literature review, the following SO_2 technologies have been identified and evaluated in this BACT analysis:

1. Amine-based scrubbing of refinery fuel gas
2. Flue Gas Desulfurization, and
3. Merox/Caustic Scrubbing and Oil Absorber to lower Total Sulfur to < 40 ppm.

Step 2 – Eliminate Technically Infeasible Options

Amine-based solvent scrubbing of refinery fuel gas: This control technology is used throughout the refining industry and is extremely effective at removing H_2S. There are other similar solvents for H_2S removal, but they all result in similar levels of sulfur removal and have no inherent advantages. The LRC refinery utilizes MDEA (methyl diethanolamine) scrubbers to remove H_2S from the refinery fuel gas prior to combustion in any of the facility's heaters and boilers. H_2S in the untreated fuel gas is by far the dominant sulfur species present. Therefore, for the purposes of this analysis, continued use of the refinery's existing and effective MDEA scrubbing system is the only H_2S scrubbing system considered.

Refineries, including the LRC facility, have long been required to meet NSPS J which requires treatment of the fuel gas to remove H_2S below 162 ppm on a 3-hr average. Achieving this minimal fuel sulfur quality is considered the baseline level of control for this BACT analysis.

The use of MDEA at LRC typically achieves H_2S concentrations well below this level. Accordingly, two levels of H_2S removal are evaluated in this BACT analysis:

- Treatment to <162 ppm H_2S, as a 3-hr average. (NSPS J)
- Treatment to <60 ppm H_2S, as an annual average (NSPS Ja)

The use of MDEA amine-based solvent scrubbing to treat to either of these levels are technically feasible control options. (Neither control option is assumed to control non-H_2S sulfur species in the fuel gas, which is assumed to be an additional 50 ppm TRS at LRC).

Flue Gas Desulfurization (FGD)

Flue gas desulfurization systems are typically comprised of either of a spray dryer that uses lime as a reagent followed by particulate control or a wet scrubber that uses limestone as a reagent. The concentration of SO_2 in the exhaust gas is the driving force for the reaction between SO_2 and the reagent. Therefore, removal efficiencies are significantly reduced with lower inlet concentrations of SO_2. FGD systems are often used for SO_2 control of coal boilers or combustion of high sulfur fuel oil. Those systems have high concentrations of SO_2 in the exhaust. To our knowledge FGD has never been used for SO_2 control on combustion of relatively low sulfur gaseous fuels as is the case with LRC refinery fuel gas. FGD is not expected to be effective in this service because of the low driving force for reaction with the reagent. Consequently, it is not considered technically feasible for these LRC heaters.

Merox/Caustic Scrubbing and Oil Absorber

As described previously, amine-based solvents do not effectively remove other sulfur species (assumed to be equal to approximately 50 ppm at LRC). In order to further lower fuel gas total reduced sulfur (TRS), additional fuel treatment is required. Technologies that are expected to be effective for mercaptan removal include some combination of the following processes:

- Once through caustic wash tower (H2S and some mercaptan removal),
- Merox caustic wash tower (to remove mercaptan and convert them to disulfide oil), and
- Sponge oil absorber (to remove the disulfide oil).

Use of these technologies, along with effective amine (MDEA) treatment, is expected to result in total fuel sulfur levels below 40 ppm (sum of H_2S and other non-H_2S sulfur species). This is a technically feasible control option.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The control technologies discussed above in Step 2 that are considered technically feasible are the use of MDEA (to various levels of control) and use of TRS treatment steps of merox/caustic wash and oil absorber. As discussed above, FGD is not considered technical feasible. These available technologies are next ranked in order of effectiveness as shown in the below Table 5-2.2 along with the resulting SO_2 total emissions rates from B001 and B004.

Table 5-2.2
Control Technology Ranking

Control Option	Fuel Treatment Control Technology	Fuel Sulfur Species	Total Fuel Sulfur	Total Emissions (B001/4) Tons/yr
TRS Treatment	MDEA + Merox/ Caustic wash + Oil Absorber.	40 ppm total Sulfur	40 ppm	15.74
NSPS Subpart Ja (Proposed)	MDEA	60 ppm H2S + 50 ppm other Sulfur	110 ppm	78.71
Baseline (NSPS J)	MDEA	162 ppm H2S + 50 ppm other Sulfur	212 ppm	151.69

Step 4 - Evaluation of Control Technologies

This step involves the consideration of energy, environmental, and economic impacts associated with each feasible control technology.

For this economic analysis, the baseline emissions level assumes that average fuel gas sulfur levels merely comply with NSPS J (162 ppm H_2S). Based on the assumption that the LRC fuel gas has an additional 50 ppm of non-H_2S sulfur species, this baseline level is equivalent to 212 ppm total reduced sulfur (TRS). The next lowest level of control is compliance with 60 ppm H_2S as required by NSPS Ja. (which corresponds to an estimated 110 ppm TRS?) LRC's current refinery fuel gas performance already achieves the next level of control. Accordingly, there are no expected incremental costs to comply with the NSPS Ja level of control proposed.

The highest level of control is to control total reduced sulfur to <40 ppm. This will require significant additional expenses as shown in below Table 5.2-3.

Table 5-2.3
Cost-Effectiveness Analysis of Technically Feasible SO2 Controls

Control Option	Total Fuel Sulfur	Total Emissions Tons/yr	Total Capital Costs $	Annualized Capital Recovery $/yr	Annual Operating Costs $/yr	Total Annual Costs $/yr	Average Cost Effectiveness (vs baseline) $/Ton	Incremental Cost Effect. (vs. NSPS Ja) $/Ton
TRS Treatment	40 ppm	15.74	$21,000,000	$1,982,000	$420,000	$2,402,000	$17,700	$38,100
NSPS Subpart Ja	110 ppm	78.71	$0	$0	n/a	n/a	n/a	n/a
Baseline (NSPS J)	212 ppm	151.69						

Notes:

- Capital Recovery calculation assumes a 20 year life and 7% interest. (The resultant Capital Recovery Factor (CRF) is 0.0944.)
- For conservatism, the TRS treatment option above is assumed to achieve up to 80% reduction of total sulfur in fuel gas vs NSPS Ja allowed levels.

The cost estimate for the Total Capital Investment for the TRS treatment option was developed to reflect a new treatment system on the fuel gas to these two LRC heaters (B001 and B004 which have a combined maximum fuel gas design flow rate of 13,000 scfm). This site-specific cost estimate was based on literature review findings and primarily utilized the lowest cost of such treatment found in literature.[3] Cost estimates by others (i.e.; letters to US EPA in response to proposed NSPS Ja) suggest even higher costs. Therefore, this estimate is believed to be conservative.

Total annual operating and maintenance costs for TRS treatment are assumed to be equal to 2% of total capital investment (TCI). This is at the lower end of the range of costs indicated by our literature review (sources indicate operating costs ranging from 2 to 5% of TCI).

[3] Letter from BP to Washington State Depart. of Ecology, June 25, 2008, "Response to Questions and Issues Related to Cherry Point BART Technical Analysis Report"

Step 5 – Select BACT for NO_X Control

The final step in the top-down analysis process is to select BACT. For this case, the final selection of BACT comes down to a question of the cost-effectiveness of the control options. Cost effectiveness is the economic criterion used to assess the potential for achieving an objective. While there is no specific published value, a control technology costing approximately $10,000 per ton of pollutant controlled is a common cut-off for cost-effectiveness for SO_2. Based on the site-specific estimates presented in Table 5-2.3, both the average and incremental cost-effectiveness for adding TRS controls to these heaters is significantly more than this level. These costs are not considered reasonable and this level of control should not be required as BACT.

BACT Proposal: It is proposed that the BACT permit limit for SO_2 emissions from reconstructed refinery heaters B001 and B004 be stated as compliance with the new NSPS Ja standard for H2S of 162 ppmv on a short term (3-hour) average and 60 ppmv on a rolling 365-day average.

Exhibit 2 – Revised Table 5-5

Revised Table 5-5
Summary of Top-down BACT Impact Analysis for NOx Controls

Emissions Unit	Control Alternative	NOx Emissions (tpy)	Emissions Reduction vs Baseline (tpy)	Total Insalled Capital Cost ($)	Total Annualized Cost ($/yr)	Average Cost Effectivness ($/ton vs Baseline)	Incremental Cost Effectiveness ($/ton vs Proposed ULNB)
Crude II Heater (B004) 624 MMBtu/hr	SCR + ULNB	10.9	98.4	$19,754,340	$1,983,303	$20,157	$27,169
	SCR (w/o ULNB)	14.6	94.7	$19,196,340	$1,922,258	$20,288	$27,732
	ULNB (Proposed)	82.0	27.3	$558,000	$52,675	$1,927	
	Baseline (existing heater performance - regular burners)	109.3					

Exhibit 3
Explanation for No Increased Acid Gas Flaring

The COF project is expected to result in a reduction in Startup/Shutdown/Malfunction acid gas flaring as a result of a number of process improvements and new facilities. The COF permit review did not take credit for any decrease – so the magnitude of the decrease was not quantified in the permit application. However, the permit did assume there would be no increase. The following provides a detailed explanation of the primary reasons that no upset or malfunction emissions increase is expected.

- Historic acid gas flaring is primarily from upset events related to the lack of redundancy and capacity.
- The COF Project's installation of the new sour water stripper, the third Claus unit and the 2nd TGTU unit will build redundancy and capacity into the existing system.
- The redundant Sour Water Stripper will allow operations to continue without disruption in the event one of the strippers comes off line, thus avoiding shutdown/startup cycles.
- The redundancy and additional capacity in the SRU system will enable the units to better handle the pressure swings from the fuel gas treatment/amine units.
- Existing SRU #1 has limited turn-down capability at low loads. As a result, process interruptions upstream have historically had a disproportionate effect on SRU #1, causing it to trip off line on some occasions. Adding SRU #3 will include re-piping to add the ability to selectively route acid gas to any of the SRUs. This increased operating flexibility will reduce the number of occasions in which one of the SRU's will be forced to shut down due to low load.
- Additionally, the new piping and additional SRU units will allow the SRU's to run in a "balanced" operating mode in which pressure surges will be managed by distributing acid gas feed among the three Claus Units, resulting in fewer and less severe pressure fluctuations than in prior operations. This will also reduce both frequency and severity of flaring.
- Also, acid gas flaring currently occurs occasionally during the shutdown of the last Claus unit online or during the start-up of the first Claus unit following a turnaround. The addition of a third Claus unit will not increase, and may decrease, the frequency this is necessary.

Because SSM emissions are inherently difficult to predict, LRC cannot state with certainty what the absolute quantities of those emissions will be in the future. However, for the reasons stated above, LRC can predict that their frequency and volume are likely to decrease as a result of this project.

Further, a review of recent historical SSM emissions (from 2011 and 2012) indicates that the mass of SO_2 from startup/shutdown and malfunction flaring emissions has in the recent past been quite modest (e.g. 2 to 5 tons per year, as calculated and reported for the emissions inventory). This is a two year sample, and does not reflect the scale of emissions that might be experienced in the event of major malfunctions. Those events are fortunately rare, and are therefore an inappropriate basis for determining expected emissions.

Exhibit 4
BACT Analysis - Revised Section 5.6

5.6 BACT for SO_2 from the Acid Gas Flare

Since the COF project will expand the sulfur handling capacity of the refinery (e.g. the SRU's), a corresponding increase in emergency relief capacity will also be required at the acid gas flare, which will be replaced to allow safe flaring of both the existing and new SRU units in the very worst-case emergency scenario. Although the replacement flare will have the capacity for higher emergency release rates, this project is not actually expected to result in any increase in upset flaring. Nevertheless, BACT is required for this flare and needs to address both routine flaring and emergency/malfunction emissions.

5.6.1 Routine Flaring BACT

The only routine emissions at this flare are those from the pilot and those from sweep gas used to purge the flare line and to assure that sufficient fuel is available to efficiently combust any acid gases flared. The use of natural gas for pilot and sweep gas will minimize routine SO_2 emissions.

5.6.2 Emergency Flaring BACT:

Upset emissions at this flare are very infrequent, short duration and have historically resulted in only modest levels of SO_2. Based on a review of the RBLC database and industry experience, the following potential control measures and operating practices have been identified that can help minimize acid gas flare emissions:

- Good Combustion Practices & Flare Pilot Monitoring
- Use of multiple SRU/TGU units for Redundancy/Capacity
- Development of a sulfur load shedding plan
- Development and use of a Flare Management Plan
- Root Cause Analysis and Corrective Action Plans for large releases

Each of these control measures is discussed below. Each is considered feasible and all are proposed to be required as BACT.

<u>Good Combustion Practices & Flare Pilot Monitoring</u>
The job of a flare is to provide effective combustion of the gases sent to it. In the case of sulfur compounds, efficient combustion at the flare assures that the sulfur is emitted in the relatively less harmful form of SO_2, rather than more harmful forms such as H_2S. To assure good combustion, NSPS, MACT and BACT requirements typically contain requirements for a pilot flame, minimum flared

gas heating value and maximum exit velocity. Accordingly, the following permit conditions are proposed as BACT for assuring efficient combustion:

- The flare shall be operated at all times when emissions are being vented to it;
- The flare shall be operated with a pilot flame present at all times;
- This flare shall be operated using good combustion practices as BACT which shall be demonstrated by complying with the following flare requirements of 40 CFR 60.18 (although 40 CFR 60.18 is not otherwise applicable);
- Only gases with a net heating value of 7.45 MJ/scm (200 Btu/scf) or greater shall be burned in this emissions unit. Net heating value shall be calculated as specified in 40 CFR Part 60.18(f)(3).
- The flare shall be operated with an exit velocity less than 18.3 m/sec (60 ft/sec) except as specified in sections c)(4) and c)(5).
- If the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf), the permittee may operate the flare at an exit velocity equal to or greater than 18.3 m/sec (60 ft/sec), but less than 122 m/sec (400 ft/sec).
- Non-assisted flares may be operated with an exit velocity less than the maximum permitted velocity, but not greater than 122 m/sec (400 ft/sec). The maximum permitted velocity shall be determined in accordance with 40 CFR, Part 60.18(f)(5).

<u>Use of multiple SRU/TGU units for redundancy/capacity.</u>
Emergency flaring at the acid gas flare at a refinery typically occurs as a result of some type of upset in a SRU/TGTU unit at a refinery. Refineries with only one SRU are especially vulnerable to upsets because they have no alternative outlet for acid gases besides the flare. Refineries with multiple SRU/TGU trains are greatly advantaged because they can redirect acid gases from the problem SRU/TGU to other units.

The LRC refinery currently has two SRU units routed to a single TGTU. Although the two SRU units provide some redundancy/stability, they currently are very vulnerable to any problems with the TGTU. The COF project will install a third SRU routed to its own TGTU unit. The addition of this third SRU and second TGTU will significantly improve the redundancy/stability of the sulfur recovery system. Also, the project's installation of Oxygen Enrichment capacity will allow a boost to the sulfur treatment capacity of each of the trains. These redundancy and capacity improvements are inherent parts of the COF project plan and will help serve to minimize the frequency, duration and magnitude of flaring events.

Development of a sulfur load shedding plan.

Acid gas flaring emissions can be minimized if operations can be quickly stabilized to end the flaring episode. In some circumstances, reducing the sulfur load to the SRUs can help end an acid gas flaring event, or at least minimize the amount of emissions. Accordingly, the development and use of a sulfur load-shedding procedure is an effective method to minimize acid gas flaring emergency emissions. The procedure shall include consideration of steps, when appropriate, such as the following:

- Rerouting the acid gas and sour water gas to the remaining operating SRU units,
- Holdup of sour water feed to the sour water stripping system,
- Reducing the sulfur loading from rich amine system,
- Switching to lower sulfur feedstocks (e.g.; include reducing the percentage of sour crude)

BACT shall include the development and use of a sulfur load shedding plan to minimize periods of gas release from the sulfur recovery units (Claus 1, Claus 2 and Claus 3 units) to the acid gas flare.

Development and use of a Flare Management Plan

In addition to sulfur load shedding, other potential efforts to minimize emergency flaring can be developed and implemented through a Flare Management Plan (FMP). Such a plan is required by NSPS Subpart Ja for this flare. Required elements of an NSPS Ja FMP plan include:

- A listing of all refinery process units, ancillary equipment, and fuel gas systems connected to the flare for each affected flare;
- An assessment of whether discharges to affected flares from these process units, ancillary equipment and fuel gas systems can be minimized. This shall include, among other things, consideration of minimizing of sweep gas flow rates;

A description of each affected flare including:

- A simple process flow diagram showing the interconnection of the components of the flare;
- Flare design parameters, including the maximum vent gas flow rate; minimum sweep gas flow rate; minimum purge gas flow rate (if any); maximum supplemental gas flow rate; maximum pilot gas flow rate; and, if the flare is steam-assisted, minimum total steam rate;
- A description of the monitoring parameters used to quantify the amount of flare gas recovered;
- An evaluation of the baseline flow to the flare;
- Procedures to minimize or eliminate discharges to the flare during the planned startup and shutdown of the refinery process units and ancillary equipment that are connected to the affected flare; and

- The plan should be updated periodically to account for changes in the operation of the flare, such as new connections to the flare.

Root Cause Analysis and Corrective Action Plans for large releases

In addition to the above measures, another work practice that can minimize emergency flaring is the practice of analyzing upsets to determine their root cause and whether any corrective action could prevent a reoccurrence. Such a work practice is required by NSPS Subpart Ja for this flare. Required elements of an NSPS Ja required procedures includes:

- A root cause analysis and a corrective action analysis shall be conducted anytime:
- the SO_2 emissions exceed 500 lb in any 24-hour period; or
- the discharge to the flare exceeds 500,000 standard cubic feet (scf) above the baseline in any 24-hour period;
- *Root cause analysis* means an assessment conducted through a process of investigation to determine the primary cause, and any other contributing cause(s), of a discharge of gases in excess of specified thresholds;
- *Corrective action analysis* means a description of all reasonable interim and long-term measures, if any, that are available, and an explanation of why the selected corrective action(s) is/are the best alternative(s), including, but not limited to, considerations of cost effectiveness, technical feasibility, safety and secondary impacts;
- The root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a discharge meeting one of the conditions specified above.
- If the discharge from a flare is the result of a planned startup or shutdown and the procedures of the flare management plan were followed, a root cause analysis and corrective action analysis is not required; however, the discharge must be recorded and reported.
- All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable.
- For corrective actions that cannot be fully implemented within 45 days following the discharge for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

BACT Summary:Each of these control measures and operating practices discussed above are feasible and all are proposed to be required as BACT for the acid gas flare routine and emergency emissions. In summary, they are:

- Good Combustion Practices & Flare Monitoring;
- Use of multiple SRU/TGU units for Redundancy/Capacity;

- Development of a sulfur load shedding plan;
- Development and use of a Flare Management Plan; and
- Root Cause Analysis and Corrective Action Plans for large releases.

FINAL

Division of Air Pollution Control
Permit-to-Install
for
Lima Refining Company

Facility ID:	0302020012
Permit Number:	P0114527
Permit Type:	Initial Installation
Issued:	12/23/2013
Effective:	12/23/2013

Division of Air Pollution Control
Permit-to-Install
for
Lima Refining Company

Table of Contents

Authorization

Facility ID:	0302020012
Facility Description:	Petroleum Refinery and Storage
Application Number(s):	A0047431, A0047911
Permit Number:	P0114527
Permit Description:	Crude Oil Flexibility (COF) project to include modifications to the refinery to increase the flexibility for processing crude oil with higher sulfur and acid contents.
Permit Type:	Initial Installation
Permit Fee:	$9,650.00
Issue Date:	12/23/2013
Effective Date:	12/23/2013

This document constitutes issuance to:

Lima Refining Company
1150 South Metcalf Street
Lima, OH 45804

of a Permit-to-Install for the emissions unit(s) identified on the following page.

Ohio Environmental Protection Agency (EPA) District Office or local air agency responsible for processing and administering your permit:

Ohio EPA DAPC, Northwest District Office
347 North Dunbridge Road
Bowling Green, OH 43402
(419)352-8461

The above named entity is hereby granted a Permit-to-Install for the emissions unit(s) listed in this section pursuant to Chapter 3745-31 of the Ohio Administrative Code. Issuance of this permit does not constitute expressed or implied approval or agreement that, if constructed or modified in accordance with the plans included in the application, the emissions unit(s) of environmental pollutants will operate in compliance with applicable State and Federal laws and regulations, and does not constitute expressed or implied assurance that if constructed or modified in accordance with those plans and specifications, the above described emissions unit(s) of pollutants will be granted the necessary permits to operate (air) or NPDES permits as applicable.

This permit is granted subject to the conditions attached hereto.

Ohio Environmental Protection Agency

Scott J. Nally
Director

Authorization (continued)

Permit Number: P0114527
Permit Description: Crude Oil Flexibility (COF) project to include modifications to the refinery to increase the flexibility for processing crude oil with higher sulfur and acid contents.

Permits for the following Emissions Unit(s) or groups of Emissions Units are in this document as indicated below:

Emissions Unit ID:	**B001**
Company Equipment ID:	Process Heater
Superseded Permit Number:	P0109701
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**B004**
Company Equipment ID:	Process Heater
Superseded Permit Number:	P0109701
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**J011**
Company Equipment ID:	DO Rail Load Rack
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P005**
Company Equipment ID:	Process
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P037**
Company Equipment ID:	LIU Cooling Tower
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P040**
Company Equipment ID:	SRU Claus TGTU
Superseded Permit Number:	P0107933
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P049**
Company Equipment ID:	SRU 3
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P050**
Company Equipment ID:	Acid Gas Flare
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable

A. Standard Terms and Conditions

1. Federally Enforceable Standard Terms and Conditions

a) All Standard Terms and Conditions are federally enforceable, with the exception of those listed below which are enforceable under State law only:

(1) Standard Term and Condition A.2.a), Severability Clause

(2) Standard Term and Condition A.3.c) through A. 3.e)General Requirements

(3) Standard Term and Condition A.6.c) and A. 6.d), Compliance Requirements

(4) Standard Term and Condition A.9., Reporting Requirements

(5) Standard Term and Condition A.10., Applicability

(6) Standard Term and Condition A.11.b) through A.11.e), Construction of New Source(s) and Authorization to Install

(7) Standard Term and Condition A.14., Public Disclosure

(8) Standard Term and Condition A.15., Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations

(9) Standard Term and Condition A.16., Fees

(10) Standard Term and Condition A.17., Permit Transfers

2. Severability Clause

a) A determination that any term or condition of this permit is invalid shall not invalidate the force or effect of any other term or condition thereof, except to the extent that any other term or condition depends in whole or in part for its operation or implementation upon the term or condition declared invalid.

b) All terms and conditions designated in parts B and C of this permit are federally enforceable as a practical matter, if they are required under the Act, or any of its applicable requirements, including relevant provisions designed to limit the potential to emit of a source, are enforceable by the Administrator of the U.S. EPA and the State and by citizens (to the extent allowed by section 304 of the Act) under the Act. Terms and conditions in parts B and C of this permit shall not be federally enforceable and shall be enforceable under State law only, only if specifically identified in this permit as such.

3. General Requirements

a) Any noncompliance with the federally enforceable terms and conditions of this permit constitutes a violation of the Act, and is grounds for enforcement action or for permit revocation, revocation and re-issuance, or modification.

b) It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the federally enforceable terms and conditions of this permit.

c) This permit may be modified, revoked, or revoked and reissued, for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or revocation, or of a notification of planned changes or anticipated noncompliance does not stay any term and condition of this permit.

d) This permit does not convey any property rights of any sort, or any exclusive privilege.

e) The permittee shall furnish to the Director of the Ohio EPA, or an authorized representative of the Director, upon receipt of a written request and within a reasonable time, any information that may be requested to determine whether cause exists for modifying or revoking this permit or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Director or an authorized representative of the Director, copies of records required to be kept by this permit. For information claimed to be confidential in the submittal to the Director, if the Administrator of the U.S. EPA requests such information, the permittee may furnish such records directly to the Administrator along with a claim of confidentiality.

4. Monitoring and Related Record Keeping and Reporting Requirements

a) Except as may otherwise be provided in the terms and conditions for a specific emissions unit, the permittee shall maintain records that include the following, where applicable, for any required monitoring under this permit:

(1) The date, place (as defined in the permit), and time of sampling or measurements.

(2) The date(s) analyses were performed.

(3) The company or entity that performed the analyses.

(4) The analytical techniques or methods used.

(5) The results of such analyses.

(6) The operating conditions existing at the time of sampling or measurement.

b) Each record of any monitoring data, testing data, and support information required pursuant to this permit shall be retained for a period of five years from the date the record was created. Support information shall include, but not be limited to all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Such records may be maintained in computerized form.

c) Except as may otherwise be provided in the terms and conditions for a specific emissions unit, the permittee shall submit required reports in the following manner:

(1) Reports of any required monitoring and/or recordkeeping of federally enforceable information shall be submitted to the Ohio EPA DAPC, Northwest District Office.

(2) Quarterly written reports of (i) any deviations from federally enforceable emissionlimitations, operationalrestrictions, andcontroldeviceoperatingparameterlimitations, excluding deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06, that have been detected by the testing, monitoring and recordkeeping requirements specified in this permit, (ii) the probable cause of such deviations, and (iii) any corrective actions or preventive measures taken, shall be made to the Ohio EPA DAPC, Northwest District Office. The written reports shall be submitted (i.e., postmarked) quarterly, by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. See A.15. below if no deviations occurred during the quarter.

(3) Written reports, which identify any deviations from the federally enforceable monitoring, recordkeeping, andreportingrequirements contained in this permit shall be submitted to the Ohio EPA DAPC, Northwest District Office every six months, by January 31 and July 31 of each year for the previous six calendar months. If no deviations occurred during a six-month period, the permittee shall submit a semi-annual report, which states that no deviations occurred during that period.

(4) This permit is for an emissions unit located at a Title V facility. Each written report shall be signed by a responsible official certifying that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

d) The permittee shall report actual emissions pursuant to OAC Chapter 3745-78 for the purpose of collecting Air Pollution Control Fees.

5. Scheduled Maintenance/Malfunction Reporting

Any scheduled maintenance of air pollution control equipment shall be performed in accordance with paragraph (A) of OAC rule 3745-15-06. The malfunction, i.e., upset, of any emissions units or any associated air pollution control system(s) shall be reported to theOhio EPA DAPC, Northwest District Officein accordance with paragraph (B) of OAC rule 3745-15-06. (The definition of an upset condition shall be the same as that used in OAC rule 3745-15-06(B)(1) for a malfunction.) The verbal and written reports shall be submitted pursuant to OAC rule 3745-15-06.

Except as provided in that rule, any scheduled maintenance or malfunction necessitating the shutdown or bypassing of any air pollution control system(s) shall be accompanied by the shutdown of the emission unit(s) that is (are) served by such control system(s).

6. Compliance Requirements

a) All applications, notifications or reports required by terms and conditions in this permit to be submitted or "reported in writing" are to be submitted to Ohio EPA through the Ohio EPA's eBusiness Center: Air Services web service ("Air Services"). Ohio EPA will accept hard copy submittals on an as-needed basis if the permittee cannot submit the required documents through the Ohio EPA eBusiness Center. In the event of an alternative hard copy submission in lieu of the eBusiness Center, the post-marked date or the date the document is delivered in person will be recognized as the date submitted. Electronic submission of applications, notifications or reports required to be submitted to Ohio EPA fulfills the requirement to submit the required information to the Director, the appropriate Ohio EPA District Office or contracted local air agency, and/or any other individual or organization specifically identified as an additional recipient identified in this permit unless otherwise specified. Consistent with OAC rule 3745-15-03, the electronic signature date shall constitute the date that the required application, notification or report is considered to be "submitted". Any document requiring signature may be represented by entry of the personal identification number (PIN) by responsible official as part of the electronic submission process or by the scanned attestation document signed by the Authorized Representative that is attached to the electronically submitted written report.

Any document (including reports) required to be submitted and required by a federally applicable requirement in this permit shall include a certification by a Responsible Official that, based on information and belief formed after reasonable inquiry, the statements in the document are true, accurate, and complete.

b) Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Director of the Ohio EPA or an authorized representative of the Director to:

(1) At reasonable times, enter upon the permittee's premises where a source is located or the emissions-related activity is conducted, or where records must be kept under the conditions of this permit.

(2) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit, subject to the protection from disclosure to the public of confidential information consistent with ORC section 3704.08.

(3) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit.

(4) As authorized by the Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit and applicable requirements.

c) The permittee shall submit progress reports to the Ohio EPA DAPC, Northwest District Office concerning any schedule of compliance for meeting an applicable requirement. Progress reports shall be submitted semiannually or more frequently if specified in the applicable requirement or by the Director of the Ohio EPA. Progress reports shall contain the following:

(1) Dates for achieving the activities, milestones, or compliance required in any schedule of compliance, and dates when such activities, milestones, or compliance were achieved.

(2) An explanation of why any dates in any schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

7. Best Available Technology

As specified in OAC Rule 3745-31-05, new sources that must employ Best Available Technology (BAT) shall comply with the Applicable Emission Limitations/Control Measures identified as BAT for each subject emissions unit.

8. Air Pollution Nuisance

The air contaminants emitted by the emissions units covered by this permit shall not cause a public nuisance, in violation of OAC rule 3745-15-07.

9. Reporting Requirements

The permittee shall submit required reports in the following manner:

a) Reports of any required monitoring and/or recordkeeping of state-only enforceable information shall be submitted to the Ohio EPA DAPC, Northwest District Office.

b) Except as otherwise may be provided in the terms and conditions for a specific emissions unit, quarterly written reports of (a) any deviations (excursions) from state-only required emission limitations, operational restrictions, and control device operating parameter limitations that have been detected by the testing, monitoring, and recordkeeping requirements specified in this permit, (b) the probable cause of such deviations, and (c) any corrective actions or preventive measures which have been or will be taken, shall be submitted to the Ohio EPA DAPC, Northwest District Office. If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted quarterly, by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. (These quarterly reports shall exclude deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06.)

10. Applicability

This Permit-to-Install is applicable only to the emissions unit(s) identified in the Permit-to-Install. Separate application must be made to the Director for the installation or modification of any other emissions unit(s)not exempt from the requirement to obtain a Permit-to-Install.

11. Construction of New Sources(s) and Authorization to Install

a) This permit does not constitute an assurance that the proposed source will operate in compliance with all Ohio laws and regulations. This permit does not constitute expressed or implied assurance that the proposed facility has been constructed in accordance with the application and terms and conditions of this permit. The action of beginning and/or completing construction prior to obtaining the Director's approval constitutes a violation of OAC rule 3745-31-02. Furthermore, issuance of this permit does not constitute an assurance that the proposed source will operate in compliance with all Ohio laws and regulations. Issuance of this permit is not to be construed as a waiver of any rights that the Ohio Environmental Protection Agency (or other persons) may have against the applicant for starting construction prior to the effective date of the permit. Additional facilities shall be installed upon orders of the Ohio Environmental Protection Agency if the proposed facilities cannot meet the requirements of this permit or cannot meet applicable standards.

b) If applicable, authorization to install any new emissions unit included in this permit shall terminate within eighteen months of the effective date of the permit if the owner or operator has not undertaken a continuing program of installation or has not entered into a binding contractual obligation to undertake and complete within a reasonable time a continuing program of installation. This deadline may be extended by up to 12 months if application is made to the

Director within a reasonable time before the termination date and the permittee shows good cause for any such extension.

c) The permittee may notify Ohio EPA of any emissions unit that is permanently shut down (i.e., the emissions unit has been physically removed from service or has been altered in such a way that it can no longer operate without a subsequent "modification" or "installation" as defined in OAC Chapter 3745-31) by submitting a certification from the authorized official that identifies the date on which the emissions unit was permanently shut down. Authorization to operate the affected emissions unit shall cease upon the date certified by the authorized official that the emissions unit was permanently shut down. At a minimum, notification of permanent shut down shall be made or confirmed by marking the affected emissions unit(s) as “permanently shut down” in “Air Services” along with the date the emissions unit(s) was permanently removed and/or disabled. Submitting the facility profile update electronically will constitute notifying the Director of the permanent shutdown of the affected emissions unit(s).

d) The provisions of this permit shall cease to be enforceable for each affected emissions unit after the date on which an emissions unit is permanently shut down (i.e., emissions unit has been physically removed from service or has been altered in such a way that it can no longer operate without a subsequent "modification" or "installation" as defined in OAC Chapter 3745-31). All records relating to any permanently shutdown emissions unit, generated while the emissions unit was in operation, must be maintained in accordance with law. All reports required by this permit must be submitted for any period an affected emissions unit operated prior to permanent shut down. At a minimum, the permit requirements must be evaluated as part of the reporting requirements identified in this permit covering the last period the emissions unit operated.

Unless otherwise exempted,no emissions unit certified by the responsible official as being permanently shut down may resume operation without first applying for and obtaining a permit pursuant to OAC Chapter 3745-31 and OAC Chapter 3745-77 if the restarted operation is subject to one or more applicable requirements.

e) The permittee shall comply with any residual requirements related to this permit, such as the requirement to submit a deviation report, air fee emission report, or other any reporting required by this permit for the period the operating provisions of this permit were enforceable, or as required by regulation or law. All reports shall be submitted in a form and manner prescribed by the Director. All records relating to this permit must be maintained in accordance with law.

12. Permit-To-Operate Application

The permittee is required to apply for a Title V permit pursuant to OAC Chapter 3745-77. The permittee shall submit a complete Title V permit application or a complete Title V permit modification application within twelve (12) months after commencing operation of the emissions units covered by this permit. However, if operation of the proposed new or modified source(s) as authorized by this permit would be prohibited by the terms and conditions of an existing Title V permit, a Title V permit modification of such new or modified source(s) pursuant to OAC rule 3745-77-04(D) and OAC rule 3745-77-08(C)(3)(d)must be obtained beforeoperating the source in a manner that would violate the existing Title V permit requirements.

13. Construction Compliance Certification

The applicant shall identify the following dates in the “Air Services” facility profile for each new emissions unit identified in this permit.

a) Completion of initial installation date shall be enteredupon completion of construction and prior to start-up.

b) Commence operation after installation or latest modification date shall be entered within 90 days after commencing operation of the applicable emissions unit.

14. Public Disclosure

The facility is hereby notified that this permit, and all agency records concerning the operation of this permitted source, are subject to public disclosure in accordance with OAC rule 3745-49-03.

15. Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations

If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted quarterly by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters.

16. Fees

The permittee shall pay fees to the Director of the Ohio EPA in accordance with ORC section 3745.11 and OAC Chapter 3745-78. The permittee shall pay all applicable permit-to-install fees within 30 days after the issuance of any permit-to-install. The permittee shall pay all applicable permit-to-operate fees within thirty days of the issuance of the invoice.

17. Permit Transfers

Any transferee of this permit shall assume the responsibilities of the prior permit holder. The new owner must update and submit the ownership information via the “Owner/Contact Change” functionality in “Air Services” once the transfer is legally completed.The change must be submitted through “Air Services” within thirty days of the ownership transfer date.

18. Risk Management Plans

If the permittee is required to develop and register a risk management plan pursuant to section 112(r) of the Clean Air Act, as amended, 42 U.S.C. 7401 et seq. ("Act"), the permittee shall comply with the requirement to register such a plan.

19. Title IV Provisions

If the permittee is subject to the requirements of 40 CFR Part 72 concerning acid rain, the permittee shall ensure that any affected emissions unit complies with those requirements. Emissions exceeding any allowances that are lawfully held under Title IV of the Act, or any regulations adopted thereunder, are prohibited.

B. Facility-Wide Terms and Conditions

1. All the following facility-wide terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only:

    a) None.

2. The following emissions unit contained in this permit is subject to 40 CFR, Part 60, Subpart J, Standards of Performance for Petroleum Refineries: P040. NSPS Subpart J applicability for this unit is the result of a requirement in Federal consent decree addendum, civil action No. SA07CA0683RF. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website http://ecfr.gpoaccess.gov or by contacting the Ohio EPA, Northwest District Office.

    The permittee shall comply with all applicable requirements of 40 CFR, Part 60, Subpart J. The permittee shall also comply with all applicable requirements of 40 CFR, Part 60, Subpart A (General Provisions). Compliance with all applicable requirements shall be achieved by the dates set forth in 40 CFR, Part 60, Subpart J, and Subpart A.

3. The following emissions units contained in this permit are subject to 40 CFR, Part 60, Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced after May 14, 2007: B001, B004, P005, P040, P049 and P050. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website http://ecfr.gpoaccess.gov or by contacting the Ohio EPA, Northwest District Office.

    The permittee shall comply with all applicable requirements of 40 CFR, Part 60, Subpart Ja. The permittee shall also comply with all applicable requirements of 40 CFR, Part 60, Subpart A (General Provisions). Compliance with all applicable requirements shall be achieved by the dates set forth in 40 CFR, Part 60, Subpart Ja, and Subpart A.

3. The following emissions unit contained in this permit is subject to 40 CFR, Part 60, Subpart VV, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry for which Construction, Reconstruction or Modification Commenced after January 5, 1981 and on or before November 7, 2006: P040. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website http://ecfr.gpoaccess.gov or by contacting the Ohio EPA, Northwest District Office.

    The permittee shall comply with all applicable requirements of 40 CFR, Part 60, Subpart VV. The permittee shall also comply with all applicable requirements of 40 CFR, Part 60, Subpart A (General Provisions). Compliance with all applicable requirements shall be achieved by the dates set forth in 40 CFR, Part 60, Subpart VV, and Subpart A.

4. The following emissions unit contained in this permit is subject to 40 CFR, Part 60, Subpart VVa, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry for which Construction, Reconstruction or Modification Commenced after November 7, 2006: P049. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website http://ecfr.gpoaccess.gov or by contacting the Ohio EPA, Northwest District Office.

The permittee shall comply with all applicable requirements of 40 CFR, Part 60, Subpart VVa. The permittee shall also comply with all applicable requirements of 40 CFR, Part 60, Subpart A (General Provisions). Compliance with all applicable requirements shall be achieved by the dates set forth in 40 CFR, Part 60, Subpart VVa, and Subpart A.

5. The following emissions unit contained in this permit is subject to 40 CFR, Part 60, Subpart GGG, Standards of Performance for Equipment Leaks in Petroleum Refineries for which Construction, Reconstruction or Modification Commenced after January 4, 1983 and on or before November 7, 2006: P040. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website http://ecfr.gpoaccess.gov or by contacting the Ohio EPA, Northwest District Office.

   The permittee shall comply with all applicable requirements of 40 CFR, Part 60, Subpart GGG. The permittee shall also comply with all applicable requirements of 40 CFR, Part 60, Subpart A (General Provisions). Compliance with all applicable requirements shall be achieved by the dates set forth in 40 CFR, Part 60, Subpart GGG, and Subpart A.

6. The following emissions unit contained in this permit is subject to 40 CFR, Part 60, Subpart GGGa, Standards of Performance for Equipment Leaks in Petroleum Refineries for which Construction, Reconstruction or Modification Commenced after November 7, 2006: P049. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website http://ecfr.gpoaccess.gov or by contacting the Ohio EPA, Northwest District Office.

   The permittee shall comply with all applicable requirements of 40 CFR, Part 60, Subpart GGGa. The permittee shall also comply with all applicable requirements of 40 CFR, Part 60, Subpart A (General Provisions). Compliance with all applicable requirements shall be achieved by the dates set forth in 40 CFR, Part 60, Subpart GGGa, and Subpart A.

7. The following emissions units contained in this permit are subject to 40 CFR, Part 61, Subpart V, National Emission Standard for Equipment Leaks (Fugitive Emission Sources): P040 and P049. The complete NESHAPS requirements, including the NESHAPS General Provisions may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website http://ecfr.gpoaccess.gov or by contacting the Ohio EPA, Northwest District Office.

   The permittee shall comply with all applicable requirements of 40 CFR, Part 61, Subpart V. The permittee shall also comply with all applicable requirements of 40 CFR, Part 61, Subpart A (General Provisions). Compliance with all applicable requirements shall be achieved by the dates set forth in 40 CFR, Part 61, Subpart V, and Subpart A.

8. The following emissions units contained in this permit are subject to 40 CFR, Part 61, Subpart FF, National Emission Standard for Benzene Waste Operations: P040 and P049. The complete NESHAPS requirements, including the NESHAPS General Provisions may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website http://ecfr.gpoaccess.gov or by contacting the Ohio EPA, Northwest District Office.

   The permittee shall comply with all applicable requirements of 40 CFR, Part 61, Subpart FF. The permittee shall also comply with all applicable requirements of 40 CFR, Part 61, Subpart A (General Provisions). Compliance with all applicable requirements shall be achieved by the dates set forth in 40 CFR, Part 61, Subpart FF, and Subpart A.

9. The following emissions units contained in this permit are subject to 40 CFR, Part 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries: J011, and rich amine flash drum vents in P040 and P049. The complete NESHAPS requirements, including the NESHAPS General Provisions may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website http://ecfr.gpoaccess.gov or by contacting the Ohio EPA, Northwest District Office.

   The permittee shall comply with all applicable requirements of 40 CFR, Part 63, Subpart CC. The permittee shall also comply with all applicable requirements of 40 CFR, Part 63, Subpart A (General Provisions). Compliance with all applicable requirements shall be achieved by the dates set forth in 40 CFR, Part 63, Subpart CC, and Subpart A.

10. The following emissions units contained in this permit are subject to 40 CFR, Part 63, Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries – Catalytic Cracking Units, Catalytic Reforming Units and Sulfur Recovery Units: P040 and P049. The complete NESHAPS requirements, including the NESHAPS General Provisions may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website http://ecfr.gpoaccess.gov or by contacting the Ohio EPA, Northwest District Office.

    The permittee shall comply with all applicable requirements of 40 CFR, Part 63, Subpart UUU. The permittee shall also comply with all applicable requirements of 40 CFR, Part 63, Subpart A (General Provisions). Compliance with all applicable requirements shall be achieved by the dates set forth in 40 CFR, Part 63, Subpart UUU, and Subpart A.

11. The following emissions units contained in this permit are subject to 40 CFR, Part 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters: B001 and B004. The complete NESHAPS requirements, including the NESHAPS General Provisions may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website http://ecfr.gpoaccess.gov or by contacting the Ohio EPA, Northwest District Office.

    The permittee shall comply with all applicable requirements of 40 CFR, Part 63, Subpart DDDDD. The permittee shall also comply with all applicable requirements of 40 CFR, Part 63, Subpart A (General Provisions). Compliance with all applicable requirements shall be achieved by the dates set forth in 40 CFR, Part 63, Subpart DDDDD, and Subpart A.

12. This PTI addresses a modification of the “refinery” operations associated with a project to increase the flexibility to process crude oil with higher sulfur and acid contents (heavy crude or bitumen). The requirements of this permit shall become enforceable on the date the permittee commences operation under the modification authorized by this permit. Identification of the specific date modified operation commences is required by term A.13.b) within the Standard Terms and Conditions of this permit. Authorization and permitting requirements associated with the current operation (prior to modification) of emissions units B001, B004, P005, P037, and P040 are contained in the facility’s Title V permit and are incorporated by reference (IBR) as requirements of this permit as indicated by the following:

    a) The permittee shall comply with all applicable emission limitations/control measures, operational restrictions, monitoring and record keeping requirements, reporting requirements, testing requirements, and additional term and condition requirements contained in the facility’s Final Title V Chapter 3745-77 permit with an issuance and effective date of 07/15/13. The IBR requirements shall cease to be enforceable for each emissions unit after the date an emissions unit commences operation under the modification authorized by this permit as indicated above.

13. The modification project involves the replacement of the existing acid gas flare (emissions unit P036) with a new flare (emissions unit P050). Upon startup of the new acid gas flare (P050), the existing acid gas flare (P036) shall be permanently removed from service.

    The new flare (P050) will provide emergency control for modified emissions unit P040 (Sulfur Recovery Unit - Claus 1 & 2 Units) and new emissions unit P049 (Sulfur Recovery Unit – Claus 3). During construction and periods of start-up involving changes to sulfur recovery unit (SRU) operations, the existing acid gas flare will remain in service providing control for SRU operations. During the time period the existing flare is utilized for providing control, the production of sulfur from SRU operations (P040) shall not exceed its existing design capacity of 110 tons (long) per day.

    If any connection is made to the existing acid gas flare system prior to P036's removal from service, and if such connection is a flare modification " as defined in 40 CFR 60.100a (c), then the emissions unit P036 will become an "affected facility" subject to 40 CFR, Part 60, Subpart Ja as a modified flare.

    Authorization and permitting requirements associated with operation of emissions unit P036 are contained in the facility's Title V permit. The requirements of 40 CFR, Part 60, Subpart Ja for the flare are incorporated by reference (IBR) as requirements of this permit as indicated by the following:

    a) The permittee shall comply with all applicable requirements of 40 CFR, Part 60, Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (See 40 CFR 60.100a – 109a). As specified in the rule, the work practice standards of 40 CFR 60.103a and the monitoring requirements of 40 CFR 60.107a are not required for modified flares until the later of November 11, 2015 or startup of the modified flare.

    b) IBR requirements for emissions unit P036 shall become effective upon the commencement of operation under the modification which results in the existing acid gas flare becoming an "affected facility" subject to the requirements of 40 CFR, Part 60, Subpart Ja.

    c) In association with the requirements of 40 CFR, Part 60, Subpart Ja, the permittee shall also comply with all applicable requirements of 40 CFR, Part 60, Subpart A (General Provisions). Compliance with all applicable requirements shall be achieved by the dates set forth in 40 CFR, Part 60, Subpart A.

14. The permittee shall maintain records of sulfur production, in tons (long) per day from all SRU operations beginning on the date the permittee commences operation under the modification authorized by this permit and ending the date emissions unit P036 is replaced by the new flare (emissions unit P050).

15. The permittee shall notify the Northwest District Office in writing of any daily record of sulfur production from SRU operations that exceeds 110 tons (long) per day during the time period specified in B.15 above. This notification shall identify the cause for the exceedance and the actual sulfur production, in tons (long). This notification shall be submitted to the Northwest District Office within 15 days after the exceedance.

16. The permittee shall maintain the following records to demonstrate that the crude oil flexibility modification project, as described in PTI application A0049711 submitted on May 29, 2013 does not trigger a major modification for PM, PM_{10}/ $PM_{2.5}$, and VOC:

    a) the projected actual annual emissions for PM, PM_{10}/ $PM_{2.5}$, and VOC, in tons per year, from the crude oil flexibility modification project as submitted in the PTI application A0049711 on May 29, 2013; and

    b) the total combined actual annual emissions for PM, PM_{10}/ $PM_{2.5}$, and VOC, in tons per year, for five calendar years after commencing operation of the crude oil flexibility modification project for the following existing operations which are “affected” by the crude oil flexibility modification project:

        (1) emissions units; B002, B003, B016, B027, P010, P036, and facility emissions from decanted oil tank storage and facility emissions from diesel fuel tank storage.

    It should be noted that for purposes of determining the projected actual annual emissions for “modified” operations/emission units contained in this permit (B001, B004, J011, P005, P037, P040, P049, and P050) the potential to emit reflected in allowable limitations shall be used.

17. The permittee shall notify the Northwest District Office in writing if annual emissions from all operations associated with the crude oil flexibility modification project, as specified in B.17 above, result in a significant PM, PM_{10}/$PM_{2.5}$, and/or VOC emissions increase and exceed the projected actual PM, PM_{10}/$PM_{2.5}$, and VOC emissions contained in PTI application A0049711, submitted May 29, 2013. This notification shall identify the cause for the difference from the preconstruction projection and the actual PM, PM_{10}/$PM_{2.5}$, and/or VOC emissions. This notification shall be submitted to the Northwest District Office within 60 days after the end of such year.

18. The permittee shall include new and modified natural gas piping components for emissions units B001, B004 and P049 for the crude oil flexibility project in the existing alternative leak detection and repair (LDAR) Monitoring Plan at the facility, which is listed in the facility’s current Title V permit, facility-wide term B.2. This requirement is established to ensure that LDAR is conducted for fugitive methane emissions associated with components in natural gas service.

C. Emissions Unit Terms and Conditions

1. B001, Process Heater

Operations, Property and/or Equipment Description:

Reconstruction of existing refinery fuel gas or natural gas fired vacuum unit II heater to include installation of ultra-low nitrogen oxide burners, 102.3 million Btu/hr maximum heat input (PR 175151)

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-17-10(B)(1)	See b)(2)a.
b.	OAC rule 3745-17-07(A)	Visible particulate emissions (PE) from any stack shall not exceed 20% opacity, as a 6-minute average, except as provided by the rule.
c.	OAC rule 3745-18-08(C)(1)	See b)(2)b.
d.	40 CFR, Part 63, Subpart DDDDD (40 CFR 63.7480-7575) [In accordance with 63.7575, this emissions unit is in the 'unit designed to fire Gas 1 fuels' subcategory existing process heater located at a major source of HAP emissions and subject to the applicable emissions limitations/ control requirements specified in this section.]	See b)(2)c., c)(2) and c)(3) 63.7500(a) Table 3 requirements
e.	40 CFR, Part 60, Subpart Ja	See b)(2)d. and b)(2)e.
f.	40 CFR, Part 60, Subpart A	See 40 CFR 60.1 through 60.19
g.	OAC rule 3745-31-05(D)	0.0075 lb of particulate emissions/ particulate matter less than or equal to 10 microns in diameter/particulate matter less than or equal to 2.5 microns in diameter ($PE/PM_{10}/PM_{2.5}$)/million Btu of

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		actual heat input and 3.34 tons of $PE/PM_{10}/PM_{2.5}$/yr 0.0054 lb of volatile organic compounds (VOC)/million Btu of actual heat input and 2.42 tons of VOC/yr 0.03 lb of nitrogen oxides (NOx)/million Btu of actual heat input, based upon a 365-day rolling average; 0.04 lb of NOx/million Btu of actual heat input based upon a 30-day rolling average; and 13.44 tons of NOx/rolling, 12-month period See b)(2)f. and b)(2)g.
h.	ORC 3704.03(T)	See b)(2)h.
i.	OAC rule 3745-31-05(A)(3), as effective 11/30/01	See b)(2)i. and b)(2)j.
j.	OAC rule 3745-31-05(A)(3), as effective 12/1/06	See b)(2)k.
k.	OAC rules 3745-31-10 through 3745-31-20	0.04 lb of carbon monoxide (CO)/million Btu of actual heat input, based upon a 365-day rolling average and 17.92 tons of CO/rolling, 12-month period 11.09 tons of sulfur dioxide (SO2)/rolling, 12-month period Carbon dioxide equivalents (CO_2e) emissions shall not exceed 54,151 tons per rolling, 12-month period See b)(2)l.
l.	OAC rule 3745-110	See b)(2)m.

(2) Additional Terms and Conditions

a. The emission limitation of 0.020 lb of particulate emissions (PE) per million Btu of actual heat input specified by OAC 3745-17-10(B)(1) is less stringent than the PE limitation specified pursuant to OAC rule 3745-31-05(D).

b. The emission limitation of 0.15 lb of sulfur dioxide (SO2) per million Btu of actual heat input specified by OAC 3745-18-08(C)(1) is less stringent than the SO_2 emission limitation specified pursuant to OAC rule 3745-31-05(D).

c. This emissions unit is subject to the initial notification requirements of 40 CFR, Part 63, Subpart DDDDD (Boiler MACT) as outlined in 63.9(b) (i.e., it is not subject to the emission limits, performance testing, monitoring, or site-specific monitoring plan requirements of Subpart DDDDD or any other requirements in 40 CFR, Part 63, Subpart A).

d. The permittee shall not burn any refinery fuel gas in this emissions unit that contains hydrogen sulfide (H2S) in excess of the following limitations:

i. 230 mg/dscm, as a 3-hour rolling average (0.10 grain/dscf)(the equivalent concentration is 162 parts per million by volume of H2S). This H2S standard in 40 CFR 60.104(a)(1) is also applicable if the permittee combines and combusts natural gas in any proportion with refinery fuel gas in this emissions unit, according to the fuel gas definition in 40 CFR 60.101(d); or stack SO2 not to exceed 20 parts per million by volume, dry basis, corrected to zero percent excess air; and

ii. 60 parts per million by volume of H2S, dry basis, as a 365-day rolling average; or stack SO2 not to exceed 8 parts per million by volume, dry basis, corrected to zero percent excess air.

e. The permittee shall not discharge to the atmosphere any emissions of NOx in excess of the applicable limits in NSPS Subpart Ja paragraphs b)(2)a.ii.(a) through (d).

i. The permittee shall comply with the limit in either paragraph b)(2)e.i.(i) or (ii). The permittee may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in 40 CFR 60.107a; if fuel gas composition is not monitored as specified in 40 CFR 60.107a(d), the permittee must comply with the concentration limits in paragraph b)(2)e.i.as follows:

(i) 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(ii) 0.040 pounds per million British thermal units (lb/MMBtu) higher heating value basis determined daily on a 30-day rolling average basis.

The permittee has elected to comply with NOx limits in permit condition b)(2)e.i.(ii). Therefore, the remaining monitoring and recordkeeping requirements in this permit are reflective of that compliance option. If the permittee decides to revise the compliance option at a later date as allowed by 40 CFR 60.102a(g)(2), this will be allowed upon notification to Ohio EPA. The permittee shall submit an administrative permit modification request to Ohio EPA prior to the change.

f. It is assumed that all PE are equivalent to both PM_{10} and $PM_{2.5.}$

g. This permit establishes the following federally enforceable emission limitations for the purpose of representing the potentials to emit of this emissions unit:

   i. 0.0075 lb of PE/PM_{10}/$PM_{2.5}$/million Btu of actual heat input and 3.34 tons of PE/PM_{10}/$PM_{2.5}$/yr;

   ii. 0.0054 lb of VOC/million Btu of actual heat input and 2.42 tons of VOC/yr; and

   iii. 0.03 lb of NOx/million Btu of actual heat input, based upon a 365-day rolling average; 0.04 lb of NOx/million Btu of actual heat input based upon a 30-day rolling average; and 13.44 tons of NOx/rolling, 12-month period.

h. Best Available Technology (BAT) requirements for CO and SO2 emissions under ORC 3704.03(T) have been determined to be compliance with the emission limitations and requirements established pursuant to OAC rule 3745-31-10 through 3745-31-20.

i. BAT requirements for PM_{10}, VOC and NOx emissions under OAC rule 3745-31-05(A)(3), as effective 11/30/01 have been determined to be compliance with OAC rule 3745-31-05(D); OAC rule 3745-17-07(A); and compliance with the terms and conditions of this permit.

j. The permittee has satisfied the BAT requirements for PM_{10} and VOC emissions pursuant to OAC rule 3745-31-05(A)(3), as effective November 30, 2001, in this permit. On December 1, 2006, paragraph (A)(3) of OAC rule 3745-31-05 was revised to conform to ORC changes effective August 3, 2006 (S.B. 265 changes), such that BAT is no longer required by State regulation for NAAQS pollutant emissions less than 10 tons per year. However, that rule revision has not yet been approved by U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revision to OAC rule 3745-31-05, the requirement to satisfy BAT still exists as part of the federally-approved SIP for Ohio. Once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05, then these emission limits and control measures no longer apply.

k. This rule paragraph applies once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 as part of the State Implementation Plan.

   The BAT requirements under OAC rule 3745-31-05(A)(3)(a) do not apply to the PM_{10} and VOC emissions since the potential to emit is less than 10 tons per year.

l. The permittee shall employ Best Available Control Technology (BACT) for this emissions unit. BACT has been determined to be the following:

Pollutant	BACT Requirements
SO2	Compliance with 40 CFR, Part 60, Subpart Ja: Compliance with hydrogen sulfide standards for refinery fuel gas, including 230 mg/dscm, as a 3-hour rolling average (0.10 grain/dscf)(the equivalent concentration is 162 parts per million by volume of H2S; or stack SO_2 not to exceed 20 parts per million by volume, dry basis, corrected to zero percent excess air; and 60 parts per million by volume of H2S, dry basis, as a 365-day rolling average; or stack SO_2 not to exceed 8 parts per million by volume, dry basis, corrected to zero percent excess air
CO	0.04 lb of CO/million Btu of actual heat input, based upon a 365-day rolling average, and based on good combustion practices
CO_2e	Use of low-carbon gaseous fuels (refinery fuel gas or natural gas); Heat recovery through use of a convection section and boiler feed water preheating; and Excess oxygen monitoring and annual burner tuning and heater inspection

m. Pursuant to OAC rule 3745-110-01(B)(19), this emissions unit is an existing large boiler. The emissions limitations for NOx in OAC rule 3745-110-03(C) are less stringent than the NOx BACT emission limitation established pursuant to OAC rule 3745-31-10 through 3745-31-20.

c) Operational Restrictions

(1) The permittee shall burn only refinery fuel gas or natural gas in this emissions unit.

(2) A process heater or boiler in the Gas 1 subcategory with heat input capacity of 10 million Btu per hour or greater shall conduct an annual tune-up of the boiler or process heater as specified in 40 CFR 63.7540(a)(10)(i) through 63.7540(a)(10)(vi). This tune-up frequency does not apply to limited-use boilers and process heaters, as defined in 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(3) A process heater of boiler in the Gas 1 subcategory that has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or meets the definition of limited-use boiler or process heater in 40 CFR 63.7575, shall conduct a tune-up of the boiler of process heater every 5 years as specified in 40 CFR 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance. You may delay the burner inspection specified in 40 CFR 63.7540(a)(10)(i) until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

(4) Pursuant to 40 CFR 63.7540(a)(13), if the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(5) The permittee shall have a one-time energy assessment performed by a qualified energy assessor, pursuant to work practice standards 4.a through 4.h in Table 3 of 40 CFR, Part 63, Subpart DDDDD. The subsequent report associated with this assessment shall be submitted no later than January 31, 2016.

d) Monitoring and/or Recordkeeping Requirements

(1) For each day during which the permittee burns a fuel other than refinery fuel gas or natural gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

(2) In order to demonstrate compliance with the emission limitations of:

a. 230 mg/dscm, as a 3-hour rolling average (0.10 grain/dscf)(the equivalent concentration is 162 parts per million by volume of H2S in the refinery fuel gas (and if applicable, combined fuel firing as noted in b)(2)d. above); or stack SO2 not to exceed 20 parts per million by volume, dry basis, corrected to zero percent excess air; and

b. 60 parts per million by volume of H2S, dry basis, as a 365-day rolling average; or stack SO2 not to exceed 8 parts per million by volume, dry basis, corrected to zero percent excess air;

(3) The permittee shall operate and maintain an instrument for continuously monitoring and recording the concentration (dry basis) of H2S in the refinery fuel gas or combined fuel stream before being burned in this emissions unit. The monitoring shall be conducted in accordance with 40 CFR 60.105(a)(4), as follows:

a. The span value for this instrument is 425 mg/dscm of H2S.

b. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H2S in the fuel gas being burned.

c. The performance evaluations for this H2S monitor under 40 CFR 60.13(c) shall use Performance Specification 7 of 40 CFR, Part 60, Appendix B. The permittee shall conduct a relative accuracy test audit (RATA) for the H2S continuous emission monitoring equipment at a minimum frequency of once every three years. Method 15 of 40 CFR, Part 60, Appendix A, or other approved U.S. EPA methods shall be used for conducting the RATAs.

(4) A statement of certification of the existing H2S continuous emission monitoring system (CEMS) shall be maintained on site and shall consist of a letter from the Ohio EPA detailing the results of an Agency review of the certification tests and a statement by the Agency that the system is considered certified in accordance with the requirements of 40 CFR, Part 60, Appendix B, Performance Specification 7.

Proof of certification shall be made available to representatives of the Ohio EPA, Northwest District Office upon request.

(5) The permittee shall operate and maintain existing equipment to continuously monitor and record H2S from this emissions unit in units of the applicable standard. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR, Part 60.13.

The permittee shall maintain records of all data obtained by the H2S CEMS including, but not limited to, parts per million of H2S for each cycle time of the analyzer, with no resolution less than one data point per minute required, emissions of H2S in units of the applicable standard (grain/dscf and parts per million by volume) as a rolling, 3-hour average, the results of daily zero/span calibration checks, and the magnitudes of manual calibration adjustments.

(6) The permittee shall maintain a written quality assurance/quality control plan for the CEMS designed to ensure continuous valid and representative readings of H2S. The plan shall follow the requirements of 40 CFR, Part 60, Appendix F.

A logbook dedicated to the monitoring systems must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR, Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR, Part 60, except as noted below.

Pursuant to paragraph No. 121 of the federal consent decree addendum, civil action No. SA07CA0683RF, dated 11/20/07, the permittee is required to:

a. Conduct a relative accuracy test audit of the H2S CEM at a minimum frequency of once every three years; and

b. Conduct cylinder gas audits on the H2S CEM during each quarter when a relative accuracy test audit is not conducted.

(7) The permittee shall install, operate, and maintain equipment to continuously monitor and record NOx emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR, Part 60.

The permittee shall maintain records of all data obtained by the continuous NOx monitoring system including, but not limited to:

a. emissions of NOx in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of NOx in units of the applicable standard(s) in the appropriate averaging period;

c. results of quarterly cylinder gas audits;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

f. hours of operation of the emissions unit, continuous NOx monitoring system, and control equipment;

g. the date, time, and hours of operation of the emissions unit without the control equipment and/or the continuous NOx monitoring system;

h. the date, time, and hours of operation of the emissions unit during any malfunction of the control equipment and/or the continuous NOx monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(8) The permittee shall record the following for this emissions unit:

a. the volume, in million standard cubic feet, of refinery fuel gas and natural gas combusted per month;

b. the volume, in million standard cubic feet, of refinery fuel gas and natural gas combusted per rolling, 12-month period;

c. the CO_2e emissions from the combustion of refinery fuel gas and natural gas for each month of operation, in tons (short tons), quantified in accordance with the calculation methodologies outlined in 40 CFR Part 98 and using global warming potential (GWP) values from Table A-1 in 40 CFR, Part 98, Subpart A as such table was published in 74 FR 56374, Oct. 30, 2009. (It should be noted that 40 CFR Part 98.33 quantifies GHG emissions in metric tons and emissions must be converted to short tons for purposes of this monitoring and recordkeeping requirement due to the establishment of BACT limitations involving short ton thresholds);

d. the rolling 12-month CO2e emissions from refinery fuel gas and natural gas combustion, in tons (short tons);

e. heater design documents; and

f. heater maintenance activities, as completed.

e) Reporting Requirements

(1) The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than refinery fuel gas or natural gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

(2) The permittee shall submit reports within thirty (30) days following the end of each calendar quarter to the Ohio EPA, Northwest District Office documenting any H2S CEMS downtime while the emissions unit was on line (date, time, duration, and reason), along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason, and corrective action(s) taken for each time period of source and control equipment malfunctions.

The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall be included the quarterly report.

(3) The permittee shall notify the Director (the Ohio EPA, Northwest District Office) on a quarterly basis, in writing, of:

a. All rolling, 3-hour periods during which the average concentration of H2S as measured by the H2S CEMS under 40 CFR 60.105(a)(4) exceeds 230 mg/dscm (0.10 grain/dscf)(the equivalent concentration is 162 parts per million by volume). The rolling, 3-hour average shall be determined as the arithmetic average of three contiguous 1-hour averages.

b. All rolling, 365-day periods during which the average concentration of H2S as measured by the H2S CEMS under 40 CFR 60.105(a)(4) exceeds 60 parts per million by volume, dry basis. The rolling, 365-day average shall be determined as the arithmetic average of 365 contiguous daily averages.

c. All exceedances of the 54,151 tons per rolling, 12-month period emission limitation for CO_2e emissions.

The notification shall include a copy of the record and shall be sent to the Director (the Ohio EPA, Northwest District Office) by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during previous calendar quarters.

(4) If there are no concentrations of H2S in the refinery fuel gas (or combined fuel stream, if applicable) greater than 230 mg/dscm (0.10 grain/dscf)(the equivalent concentration is 162 parts per million by volume), as a 3-hour rolling average; or 60 parts per million by volume of H2S, as a 365-day rolling average; during the calendar quarter, then the permittee shall submit a statement to that effect along with the emissions unit and monitor operating times. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during previous calendar quarters.

(5) Pursuant to the 40 CFR Part 60.7, the permittee is hereby advised of the requirement to report the following at the appropriate times:

a. Construction date (no later than 30 days after such date);

b. Anticipated start-up date (not more than 60 days or less than 30 days prior to such date);

c. Actual start-up date (within 15 days after such date); and

d. Date of performance testing (if required, at least 30 days prior to testing).

(6) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous NOx monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of NOx emissions in excess of any applicable limit specified in this permit, 40 CFR Part 60, OAC Chapters 3745-14 and 3745-23, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous NOx and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total NOx emissions for the calendar quarter (tons);

vi. the total operating time (hours) of the emissions unit;

vii. the total operating time of the continuous NOx monitoring system while the emissions unit was in operation;

viii. results and dates of quarterly cylinder gas audits;

ix. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

x. unless previously submitted, the results of any relative accuracy test audit showing the continuous NOx monitor out-of-control and the compliant results following any corrective actions;

xi. the date, time, and duration of any/each malfunction** of the continuous NOx monitoring system, emissions unit, and/or control equipment;

xii. the date, time, and duration of any downtime** of the continuous NOx monitoring system and/or control equipment while the emissions unit was in operation; and

xiii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(xi) and (xii).

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

Visible PE from any stack shall not exceed 20% opacity, as a 6-minute average, except as provided by the rule.

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance with the visible particulate emission limitation above in accordance with the methods and procedures specified in Method 9 of 40 CFR, Part 60, Appendix A, and the requirements specified in OAC rule 3745-17-03(B)(1).

b. Emission Limitation:

230 mg/dscm (0.10 grain/dscf)(the equivalent concentration is 162 parts per million by volume) of H2S, as a 3-hour rolling average, in the refinery fuel gas, or combined fuel stream if applicable

Applicable Compliance Method:

Compliance shall be based upon the monitoring and record keeping requirements specified in sections d)(2) through d)(5) for this emissions unit. If required, the permittee shall determine compliance with the H2S emission limitation by using Method 15 of 40 CFR, Part 60, Appendix A, or other U.S. EPA-approved methods.

c. Emission Limitation:

60 parts per million by volume of H2S, dry basis, as a 365-day rolling average, in the refinery fuel gas, or combined fuel stream if applicable

Applicable Compliance Method:

Compliance shall be based upon the monitoring and record keeping requirements specified in sections d)(2) through d)(5) for this emissions unit. If required, the permittee shall determine compliance with the H2S emission limitation by using Method 15 of 40 CFR, Part 60, Appendix A, or other U.S. EPA-approved methods.

d. Emission Limitations:

0.0075 lb of PE/PM_{10}/$PM_{2.5}$/million Btu of actual heat input and 3.34 tons of PE/PM_{10}/$PM_{2.5}$/yr

Applicable Compliance Method:

The PE/PM_{10}/$PM_{2.5}$ emission limitation above was developed by dividing the PM_{10}/$PM_{2.5}$ emission factor from AP-42, Table 1.4-2 (dated 7/98) (7.6 lb/mmscf) by the average heating value for natural gas specified in AP-42, Table 1.4-2 (dated 7/98) (1,020 Btu/scf). Compliance is presumed by only using gaseous fuels as required in C.1.(c)(1).

If required, the permittee shall demonstrate compliance with the hourly emission limitation by conducting emission testing in accordance with the methods and procedures specified in Methods 201, 201A and 202 of 40 CFR, Part 51, Appendix M. Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA.

The annual emission limitation was established by multiplying the lb/million Btu emission limitation by the design heat input (102.3 million Btu/hr), and then multiplying by the maximum operating schedule of 8,760 hrs/yr and dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the lb/million Btu emission limitation, compliance with the annual emission limitation shall also be demonstrated.

e. Emission Limitations:

0.0054 lb of VOC/million Btu of actual heat input and 2.42 tons of VOC/yr

Applicable Compliance Method:

The VOC emission limitation above was developed by dividing the VOC emission factor from AP-42, Table 1.4-2 (dated 7/98) (5.5 lb/mmscf) by the average heating value for natural gas specified in AP-42, Table 1.4-2 (dated 7/98) (1,020 Btu/scf). Compliance is presumed by only using gaseous fuels as required in C.1.(c)(1).

If required, the permittee shall demonstrate compliance with the hourly emission limitation by conducting emission testing in accordance with the methods and procedures specified in Methods 1 through 4, and 18, 25, or 25A, as appropriate, of 40 CFR, Part 60, Appendix A.

Use of Method 18, 25, or 25A is to be selected based on the results of a pre-survey stack sampling and U.S. EPA guidance documents. Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA.

The annual emission limitation was established by multiplying the lb/million Btu emission limitation by the design heat input (102.3 million Btu/hr), then multiplying by the maximum operating schedule of 8,760 hrs/yr and dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the lb/million Btu emission limitation, compliance with the annual emission limitation shall also be demonstrated.

f. Emission Limitations:

0.03 lb of NOx/million Btu of actual heat input based upon a 365-day rolling average, 0.04 lb NOx/million Btu of actual heat input based upon a 30-day rolling average, and 13.44 tons NOx/rolling, 12-month period

Applicable Compliance Method:

Ongoing compliance with the NOx emission limitation(s) shall be demonstrated through the data collected as required in the Monitoring and Recordkeeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR, Part 60.

The rolling, 12-month emission limitation was established by multiplying the 0.03 lb NOx/million Btu of actual heat input emission limitation by the maximum heat input of 102.3 million Btu/hr,then multiplying by the maximum annual hours of operation (8,760 hrs/yr) and dividing by 2,000 pounds per ton.

Therefore, compliance is shown using the data collected as required in the Monitoring and Record keeping Section of this permit.

g. Emission Limitation:

0.04 lb of CO/million Btu of actual heat input based upon a 365-day rolling average and 17.92 tons CO/rolling, 12-month period

Applicable Compliance Method:

The permittee shall demonstrate compliance with the lb CO/million Btu of actual heat input emission limitation by conducting emission testing pursuant to Methods 1 through 4, and 10 of 40 CFR, Part 60, Appendix A.

The rolling, 12-month emission limitation was established by multiplying the 0.04 lb CO/million Btu of actual heat input emission limitation by the maximum heat input of 102.3 million Btu/hr,then multiplying by the maximum annual hours of operation (8,760 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, provided compliance is shown with the lb/million Btu of actual heat input emission limitation, compliance with the rolling, 12-month period emission limitation shall also be demonstrated.

h. Emission Limitation:

11.09 tons of SO2/rolling, 12-month period

Applicable Compliance Method:

Compliance shall be based upon the fuel flow and H2S monitoring and record keeping requirements specified in sections d)(2) through d)(5) plus a 50 ppmv allowance for non-H2S sulfur based on EPA published refinery test data, or more recent test value if future testing is performed. If required, the permittee shall determine compliance with the SO2 emission limitation by using Method 6 of 40 CFR, Part 60, Appendix A, or other U.S. EPA-approved methods.

i. Emission Limitation:

CO_2e emissions shall not exceed 54,151 tons per rolling, 12-month period

Applicable Compliance Method:

Compliance shall be based upon the monitoring and record keeping requirements specified in section d)(8) for this emissions unit.

(2) The permittee shall conduct, or have conducted, emission testing for this emissions unit in accordance with the following requirements:

a. The emission testing shall be conducted within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of the emissions unit.

b. The emission testing shall be conducted to demonstrate compliance with the lb of CO/million Btu of actual heat input limitation.

c. The following test methods shall be employed to demonstrate compliance with the allowable CO mass emission rate: Methods 1 through 4, and 10 of 40 CFR, Part 60, Appendix A.

Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

d. The test(s) shall be conducted at a Maximum Source Operating Rate (MSOR), unless otherwise specified or approved by the Ohio EPA, Northwest District Office. MSOR is defined as the condition that is most likely to challenge the emission control measures with regards to meeting the applicable emission standard(s). Although it generally consists of operating the emissions unit at its maximum material input/production rates and results in the highest emission rate of the tested pollutant, there may be circumstances where a lower emissions loading is deemed the most challenging control scenario. Failure to test at the MSOR is justification for not accepting the test results as a demonstration of compliance.

e. Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Ohio EPA, Northwest District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s).

Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA, Northwest District Office's refusal to accept the results of the emission test(s).

f. Personnel from the Ohio EPA, Northwest District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

g. A comprehensive written report on the results of the emissions test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA, Northwest District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA, Northwest District Office.

h. Within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup, the permittee shall conduct certification tests of the continuous NOx monitoring system in units of the applicable standard(s) to demonstrate compliance with 40 CFR, Part 60, Appendix B, Performance Specifications 2; and ORC section 3704.03(I).

Personnel from the Ohio EPA Central Office and the Ohio EPA Northwest District Office shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. Two copies of the test results shall be submitted to Ohio EPA, one copy to the Ohio EPA Northwest District Office and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification of the continuous NOx monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets the requirements of 40 CFR, Part 60, Appendix B, Performance Specifications 2; and ORC section 3704.03(I).

g) Miscellaneous Requirements

(1) None.

2. B004, Process Heater

Operations, Property and/or Equipment Description:

Reconstruction and modification of existing refinery fuel gas or natural gas fired crude II heater to include burner modification of existing low nitrogen oxide burners, and tube replacement, 624 million Btu/hr maximum heat input (PR 175150)

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-17-10(B)(1)	See b)(2)a.
b.	OAC rule 3745-17-07(A)	Visible particulate emissions (PE) from any stack shall not exceed 20% opacity, as a 6-minute average, except as provided by the rule.
c.	OAC rule 3745-18-08(C)(2)	See b)(2)b.
d.	40 CFR, Part 63, Subpart DDDDD (40 CFR 63.7480-7575) [In accordance with 63.7575, this emissions unit is in the 'unit designed to fire Gas 1 fuels' subcategory existing process heater located at a major source of HAP emissions and subject to the applicable emissions limitations/ control requirements specified in this section.]	See b)(2)c., c)(2) and c)(3) 63.7500(a) Table 3 requirements
e.	40 CFR, Part 60, Subpart Ja	See b)(2)d. and b)(2)e.
f.	40 CFR, Part 60, Subpart A	See 40 CFR 60.1 through 60.19
g.	OAC rule 3745-31-05(D)	0.0075 lb of particulate emissions/ particulate matter less than or equal to 10 microns in diameter/particulate matter less than or equal to 2.5 microns in

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		diameter ($PE/PM_{10}/PM_{2.5}$)/million Btu of actual heat input and 20.36 tons of $PE/PM_{10}/PM_{2.5}$/yr 0.0054 lb of volatile organic compounds (VOC)/million Btu of actual heat input and 14.74 tons of VOC/yr See b)(2)f. and b)(2)g.
h.	ORC 3704.03(T)	See b)(2)h.
i.	OAC rule 3745-31-05(A)(3), as effective 11/30/01	See b)(2)i. and b)(2)j.
j.	OAC rule 3745-31-05(A)(3), as effective 12/1/06	See b)(2)k.
k.	OAC rules 3745-31-10 through 3745-31-20	0.03 lb nitrogen oxides (NOx)/million Btu of actual heat input based upon a 365-day rolling average, 0.04 lb/million Btu of actual heat input based upon a 30-day rolling average, and 81.99 tons NOx/rolling, 12-month period 0.04 lb of carbon monoxide (CO)/million Btu of actual heat input based upon a 365-day rolling average and 109.32 tons CO/rolling, 12-month period 67.62 tons of sulfur dioxide (SO2)/rolling, 12-month period Carbon dioxide equivalents (CO_2e) emissions shall not exceed 330,308 tons per rolling, 12-month period See b)(2)l.
l.	OAC rule 3745-110	See b)(2)m.

(2) Additional Terms and Conditions

a. The emission limitation of 0.020 lb of particulate emissions (PE) per million Btu of actual heat input specified by OAC 3745-17-10(B)(1) is less stringent than the PE limitation specified pursuant to OAC rule 3745-31-05(D).

b. The emission limitation of 1.0 lb of sulfur dioxide (SO2) per million Btu of actual heat input specified by OAC 3745-18-08(C)(2) is less stringent than the SO_2 emission limitation specified pursuant to OAC rule 3745-31-05(D).

c. This emissions unit is subject to the initial notification requirements of 40 CFR, Part 63, Subpart DDDDD (Boiler MACT) as outlined in 63.9(b) (i.e., it is not subject to the emission limits, performance testing, monitoring, or site-specific monitoring plan requirements of Subpart DDDDD or any other requirements in 40 CFR, Part 63, Subpart A).

d. The permittee shall not burn any refinery fuel gas in this emissions unit that contains hydrogen sulfide (H2S) in excess of the following limitations:

   i. 230 mg/dscm, as a 3-hour rolling average (0.10 grain/dscf)(the equivalent concentration is 162 parts per million by volume of H2S). This H2S standard in 40 CFR 60.104(a)(1) is also applicable if the permittee combines and combusts natural gas in any proportion with refinery fuel gas in this emissions unit, according to the fuel gas definition in 40 CFR 60.101(d); or stack SO2 not to exceed 20 parts per million by volume, dry basis, corrected to zero percent excess air; and

   ii. 60 parts per million by volume of H2S, dry basis, as a 365-day rolling average; or stack SO2 not to exceed 8 parts per million by volume, dry basis, corrected to zero percent excess air.

e. The permittee shall not discharge to the atmosphere any emissions of NOx in excess of the applicable limits in NSPS Subpart Ja paragraphs b)(2)a.ii.(a) through (d).

   i. The permittee shall comply with the limit in either paragraph b)(2)e.i.(i) or (ii). The permittee may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in 40 CFR 60.107a; if fuel gas composition is not monitored as specified in 40 CFR 60.107a(d), the permittee must comply with the concentration limits in paragraph b)(2)e.i.as follows.

      (i) 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

      (ii) 0.040 pounds per million British thermal units (lb/MMBtu) higher heating value basis determined daily on a 30-day rolling average basis.

   The permittee has elected to comply with NOx limits in permit condition b)(2)e.i.(ii). Therefore, the remaining monitoring and recordkeeping requirements in this permit are reflective of that compliance option. If the permittee decides to revise the compliance option at a later date as allowed by 40 CFR 60.102a(g)(2), this will be allowed upon notification to Ohio EPA. The permittee shall submit an administrative permit modification request to Ohio EPA prior to the change.

f. It is assumed that all PE are equivalent to both PM_{10} and $PM_{2.5}$.

e. This permit establishes the following federally enforceable emission limitations for the purpose of representing the potential to emit of the emissions unit:

i. 0.0075 lb PE/PM_{10}/$PM_{2.5}$/million Btu of actual heat input and 20.36 tons of PE/PM_{10}/$PM_{2.5}$/yr; and

ii. 0.0054 lb of VOC/million Btu of actual heat input and 14.74 tons of VOC/yr.

f. Best Available Technology (BAT) requirements for NOx, CO and SO2 emissions under ORC 3704.03(T) have been determined to be compliance with the emission limitations and requirements established pursuant to OAC rule 3745-31-10 through 3745-31-20.

g. BAT requirements for PM_{10} and VOC emissions under OAC rule 3745-31-05(A)(3), as effective 11/30/01 have been determined to be compliance with OAC rule 3745-31-05(D); OAC rule 3745-17-07(A); and compliance with the terms and conditions of this permit.

h. The permittee has satisfied the BAT requirements for PM_{10} and VOC emissions pursuant to OAC rule 3745-31-05(A)(3), as effective November 30, 2001, in this permit. On December 1, 2006, paragraph (A)(3) of OAC rule 3745-31-05 was revised to conform to ORC changes effective August 3, 2006 (S.B. 265 changes), such that BAT is no longer required by State regulation for NAAQS pollutant emissions less than 10 tons per year. However, that rule revision has not yet been approved by U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revision to OAC rule 3745-31-05, the requirement to satisfy BAT still exists as part of the federally-approved SIP for Ohio. Once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05, then these emission limits and control measures no longer apply.

i. This rule paragraph applies once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 as part of the State Implementation Plan.

The BAT requirements under OAC rule 3745-31-05(A)(3)(a) do not apply to the PM_{10} and VOC emissions since the potential to emit is less than 10 tons per year.

j. The permittee shall employ Best Available Control Technology (BACT) for this emissions unit. BACT has been determined to be the following:

Pollutant	BACT Requirements
NOx	Use of ultra-low NOx burners; Compliance with the 40 CFR, Part 60, Subpart Ja emission standard of 0.04 lb NOx/million Btu of actual heat input, based upon a 30 day rolling average; and

	Compliance with the NOx emission standard of 0.03 lb of NOx/million Btu of actual heat input, based upon a 365-day rolling average
SO2	Compliance with 40 CFR, Part 60, Subpart Ja: Compliance with hydrogen sulfide standards for refinery fuel gas, including 230 mg/dscm, as a 3-hour rolling average (0.10 grain/dscf)(the equivalent concentration is 162 parts per million by volume of H2S; or stack SO2 not to exceed 20 parts per million by volume, dry basis, corrected to zero percent excess air; and 60 parts per million by volume of H2S, dry basis, as a 365-day rolling average; or stack SO2 not to exceed 8 parts per million by volume, dry basis, corrected to zero percent excess air
CO	0.04 lb of CO/million Btu of actual heat input, based upon a 365-day rolling average, and based on good combustion practices
CO_2e	Use of low-carbon gaseous fuels (refinery fuel gas or natural gas); Heat recovery through use of a convection section and boiler feed water preheating; and Excess oxygen monitoring and annual burner tuning and heater inspection

k. Pursuant to OAC rule 3745-110-01(B)(19), this emissions unit is an existing large boiler. The emissions limitations for NOx in OAC rule 3745-110-03(C) are less stringent than the NOx BACT emission limitation established pursuant to OAC rule 3745-31-10 through 3745-31-20.

c) Operational Restrictions

(1) The permittee shall burn only refinery fuel gas or natural gas in this emissions unit.

(2) A process heater or boiler in the Gas 1 subcategory with heat input capacity of 10 million Btu per hour or greater shall conduct an annual tune-up of the boiler or process heater as specified in 40 CFR 63.7540(a)(10)(i) through 63.7540(a)(10)(vi). This tune-up frequency does not apply to limited-use boilers and process heaters, as defined in 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(3) A process heater of boiler in the Gas 1 subcategory that has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or meets the definition of limited-use boiler or process heater in 40 CFR 63.7575, shall conduct a tune-up of the boiler of process heater every 5 years as specified in 40 CFR 63.7540(a)(10)(i) through (vi) to

demonstrate continuous compliance. You may delay the burner inspection specified in 40 CFR 63.7540(a)(10)(i) until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

(4) Pursuant to 40 CFR 63.7540(a)(13), if the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(5) The permittee shall have a one-time energy assessment performed by a qualified energy assessor, pursuant to work practice standards 4.a through 4.h in Table 3 of 40 CFR, Part 63, Subpart DDDDD. The subsequent report associated with this assessment shall be submitted no later than January 31, 2016.

d) Monitoring and/or Recordkeeping Requirements

(1) For each day during which the permittee burns a fuel other than refinery fuel gas or natural gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

(2) In order to demonstrate compliance with the emission limitations of:

a. 230 mg/dscm, as a 3-hour rolling average (0.10 grain/dscf)(the equivalent concentration is 162 parts per million by volume of H2S in the refinery fuel gas (and if applicable, combined fuel firing as noted in b)(2)d. above); or stack SO2 not to exceed 20 parts per million by volume, dry basis, corrected to zero percent excess air; and

b. 60 parts per million by volume of H2S, dry basis, as a 365-day rolling average; or stack SO2 not to exceed 8 parts per million by volume, dry basis, corrected to zero percent excess air;

(3) The permittee shall operate and maintain an instrument for continuously monitoring and recording the concentration (dry basis) of H2S in the refinery fuel gas or combined fuel stream before being burned in this emissions unit. The monitoring shall be conducted in accordance with 40 CFR 60.105(a)(4), as follows:

a. The span value for this instrument is 425 mg/dscm of H2S.

b. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H2S in the fuel gas being burned.

c. The performance evaluations for this H2S monitor under 40 CFR 60.13(c) shall use Performance Specification 7 of 40 CFR, Part 60, Appendix B. The permittee shall conduct a relative accuracy test audit (RATA) for the H2S continuous emission monitoring equipment at a minimum frequency of once every three years. Method 15 of 40 CFR, Part 60, Appendix A, or other approved U.S. EPA methods shall be used for conducting the RATAs.

(4) A statement of certification of the existing H2S continuous emission monitoring system (CEMS) shall be maintained on site and shall consist of a letter from the Ohio EPA detailing the results of an Agency review of the certification tests and a statement by the Agency that the system is considered certified in accordance with the requirements of 40 CFR, Part 60, Appendix B, Performance Specification 7. Proof of certification shall be made available to representatives of the Ohio EPA, Northwest District Office upon request.

(5) The permittee shall operate and maintain existing equipment to continuously monitor and record H2S from this emissions unit in units of the applicable standard. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR, Part 60.13.

The permittee shall maintain records of all data obtained by the H2S CEMS including, but not limited to, parts per million of H2S for each cycle time of the analyzer, with no resolution less than one data point per minute required, emissions of H2S in units of the applicable standard (grain/dscf and parts per million by volume) as a rolling, 3-hour average, the results of daily zero/span calibration checks, and the magnitudes of manual calibration adjustments.

(6) The permittee shall maintain a written quality assurance/quality control plan for the CEMS designed to ensure continuous valid and representative readings of H2S. The plan shall follow the requirements of 40 CFR, Part 60, Appendix F.

A logbook dedicated to the monitoring systems must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR, Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR, Part 60, except as noted below.

Pursuant to paragraph No. 121 of the federal consent decree addendum, civil action No. SA07CA0683RF, dated 11/20/07, the permittee is required to:

a. Conduct a relative accuracy test audit of the H2S CEM at a minimum frequency of once every three years; and

b. Conduct cylinder gas audits on the H2S CEM during each quarter when a relative accuracy test audit is not conducted.

(7) Pursuant to the federal consent decree addendum, civil action No. SA07CA0683RF, dated 11/20/07 and 40 CFR, Part 60, Subpart Ja, the permittee shall install, operate, and maintain equipment to continuously monitor and record NOx emissions from this emissions unit, in units of parts per million by volume, on a dry basis. The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.13.

The permittee shall maintain records of data obtained by the continuous NOx monitoring system including, but not limited to:

a. emissions of NOx in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of NOx in all units of the applicable standard(s) in the appropriate averaging period;

c. results of quarterly cylinder gas audits;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

f. hours of operation of the emissions unit, continuous NOx monitoring system, and control equipment;

g. the date, time, and hours of operation of the emissions unit without the control equipment and/or the continuous NOx monitoring system;

h. the date, time, and hours of operation of the emissions unit during any malfunction of the control equipment and/or the continuous NOx monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in d)(6)g. and d)(6)h.

(8) The permittee shall maintain on-site, the document of certification received from the U.S. EPA or the Ohio EPA's Central Office documenting that the continuous NOx monitoring system has been certified to meet the requirements of 40 CFR, Part 60, Appendix B, Performance Specification 2. The letter/document of certification shall be made available to the Director (the Ohio EPA, Northwest District Office) upon request.

Each continuous monitoring system consists of all the equipment used to acquire and record data in units of all applicable standard(s), and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

(9) The permittee shall maintain a written quality assurance/quality control plan for the continuous NOx monitoring system designed to ensure continuous valid and representative readings of NOx emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR, Part 60, Appendix F.

The quality assurance/quality control plan and a logbook dedicated to the continuous NOx monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR, Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR, Part 60, except as noted below.

Pursuant to paragraph No. 30 of the federal consent decree addendum, civil action No. SA07CA0683RF, dated 11/20/07, the permittee is required to:

a. Conduct a relative test audit of the NOx CEM at a minimum frequency of once every three years; and

b. Conduct cylinder gas audits on the NOx CEM during each quarter when a relative accuracy test audit is not conducted.

(10) Pursuant to the federal consent decree addendum, civil action No. SA07CA0683RF, dated 11/20/07, the permittee shall install, operate and maintain equipment to continuously monitor and record oxygen (O2) emitted from this emissions unit, in units of percent O2. The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR, Part 60.

The permittee shall maintain records of data obtained by the continuous O2 monitoring system including, but not limited to:

a. percent O2 for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. results of quarterly cylinder gas audits;

c. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

d. results of required relative accuracy test audit(s);

e. hours of operation of the emissions unit, continuous O2 monitoring system;

f. the date, time, and hours of operation of the emissions unit without the continuous O2 monitoring system;

g. the date, time, and hours of operation of the emissions unit during any malfunction of the continuous O2 monitoring system; as well as,

h. the reason (if known) and the corrective actions taken (if any) for each such event in d)(9)f. and d)(9)g.

(11) The permittee shall maintain on-site, the document of certification received from the U.S. EPA or the Ohio EPA's Central Office documenting that the continuous O2 monitoring system has been certified to meet the requirements of 40 CFR, Part 60, Appendix B, Performance Specification 3. The letter/document of certification shall be made available to the Director (the Ohio EPA, Northwest District Office) upon request.

Each continuous monitoring system consists of all the equipment used to acquire and record data in units of all applicable standard(s), and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

(12) The permittee shall maintain a written quality assurance/quality control plan for the continuous O2 monitoring system designed to ensure continuous valid and representative readings of O2 emissions in units of the applicable standard(s).

The plan shall follow the requirements of 40 CFR, Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the continuous O2 monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR, Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR, Part 60, except as noted below.

Pursuant to paragraph No. 30 of the federal consent decree addendum, civil action No. SA07CA0683RF, dated 11/20/07, the permittee is required to:

a. Conduct a relative accuracy test audit of the O2 CEM at a minimum frequency of once every three years; and

b. Conduct cylinder gas audits on the O2 CEM during each quarter when a relative accuracy test audit is not conducted.

(13) The permittee shall record the following for this emissions unit:

a. the volume, in million standard cubic feet, of refinery fuel gas and natural gas combusted per month;

b. the volume, in million standard cubic feet, of refinery fuel gas and natural gas combusted per rolling, 12-month period;

c. the CO_2e emissions from the combustion of refinery fuel gas and natural gas for each month of operation, in tons (short tons), quantified in accordance with the calculation methodologies outlined in 40 CFR Part 98 and using global warming potential (GWP) values from Table A-1 in 40 CFR Part 98 Subpart A as such table was published in 74 FR 56374, Oct. 30, 2009. (It should be noted that 40 CFR Part 98.33 quantifies GHG emissions in metric tons and emissions must be converted to short tons for purposes of this monitoring and recordkeeping requirement due to the establishment of BACT limitations involving short ton thresholds);

d. the rolling 12-month CO2e emissions from refinery fuel gas and natural gas combustion, in tons (short tons);

e. heater design documents; and

f. heater maintenance activities, as completed.

e) Reporting Requirements

(1) The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than refinery fuel gas or natural gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

(2) The permittee shall submit reports within thirty (30) days following the end of each calendar quarter to the Ohio EPA, Northwest District Office documenting any H2S CEMS downtime while the emissions unit was on line (date, time, duration, and reason), along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason, and corrective action(s) taken for each time period of source and control equipment malfunctions.

The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall be included the quarterly report.

(3) The permittee shall submit reports within thirty (30) days following the end of each calendar quarter to the Ohio EPA, Northwest District Office documenting any NOx CEMS downtime while the emissions unit was on line (date, time, duration, and reason), along with any corrective action(s) taken.

The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason, and corrective action(s) taken for each time period of source and control equipment malfunctions.

The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall be included the quarterly report.

(4) The permittee shall submit reports within thirty (30) days following the end of each calendar quarter to the Ohio EPA, Northwest District Office documenting any O2 CEMS downtime while the emissions unit was on line (date, time, duration, and reason), along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason, and corrective action(s) taken for each time period of source and control equipment malfunctions.

The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall be included the quarterly report.

(5) The permittee shall notify the Director (the Ohio EPA, Northwest District Office) on a quarterly basis, in writing, of:

a. All rolling, 3-hour periods during which the average concentration of H2S as measured by the H2S CEMS under 40 CFR 60.105(a)(4) exceeds 230 mg/dscm (0.10 grain/dscf)(the equivalent concentration is 162 parts per million by volume). The rolling, 3-hour average shall be determined as the arithmetic average of three contiguous 1-hour averages.

b. All rolling, 365-day periods during which the average concentration of H2S as measured by the H2S CEMS under 40 CFR 60.105(a)(4) exceeds 60 parts per million by volume, dry basis. The rolling, 365-day average shall be determined as the arithmetic average of 365 contiguous daily averages.

c. All rolling, 30-day periods during which the average emissions of NOx as measured by the NOx CEMS under 40 CFR 60.13 exceeds 0.04 lb NOx/million Btu of actual heat input. The rolling, 30-day average shall be determined as the arithmetic average of 30 contiguous daily averages.

d. All exceedances of the 330,308 tons per rolling, 12-month period emission limitation for CO_2e emissions.

The notification shall include a copy of the record and shall be sent to the Director (the Ohio EPA, Northwest District Office) by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during previous calendar quarters.

(6) If there are no concentrations of H2S in the refinery fuel gas (or combined fuel stream, if applicable) greater than 230 mg/dscm (0.10 grain/dscf)(the equivalent concentration is 162 parts per million by volume), as a 3-hour rolling average; or 60 parts per million by volume of H2S, as a 365-day rolling average; or 0.04 lb NOx/million Btu of actual heat input, as a 30-day rolling average, during the calendar quarter, then the permittee shall submit a statement to that effect along with the emissions unit and monitor operating times.

These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during previous calendar quarters.

(7) Pursuant to the 40 CFR Part 60.7, the permittee is hereby advised of the requirement to report the following at the appropriate times:

a. Construction date (no later than 30 days after such date);

b. Anticipated start-up date (not more than 60 days or less than 30 days prior to such date);

c. Actual start-up date (within 15 days after such date); and

d. Date of performance testing (if required, at least 30 days prior to testing).

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

Visible PE from any stack shall not exceed 20% opacity, as a 6-minute average, except as provided by the rule.

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance with the visible particulate emission limitation above in accordance with the methods and procedures specified in Method 9 of 40 CFR, Part 60, Appendix A, and the requirements specified in OAC rule 3745-17-03(B)(1).

b. Emission Limitation:

230 mg/dscm (0.10 grain/dscf)(the equivalent concentration is 162 parts per million by volume) of H2S, as a 3-hour rolling average, in the refinery fuel gas, or combined fuel stream if applicable

Applicable Compliance Method:

Compliance shall be based upon the monitoring and record keeping requirements specified in sections d)(2) through d)(5) for this emissions unit. If required, the permittee shall determine compliance with the H2S emission limitation by using Method 15 of 40 CFR, Part 60, Appendix A, or other U.S. EPA-approved methods.

c. Emission Limitation:

60 parts per million by volume of H2S, dry basis, as a 365-day rolling average, in the refinery fuel gas, or combined fuel stream if applicable

Applicable Compliance Method:

Compliance shall be based upon the monitoring and record keeping requirements specified in sections d)(2) through d)(5) for this emissions unit. If required, the permittee shall determine compliance with the H2S emission limitation by using Method 15 of 40 CFR, Part 60, Appendix A, or other approved U.S. EPA methods.

d. Emission Limitation:

0.0075 lb of PE/PM_{10}/$PM_{2.5}$/million Btu of actual heat input and 20.36 tons of PE/PM_{10}/$PM_{2.5}$/yr

Applicable Compliance Method:

The PE/PM_{10}/$PM_{2.5}$ emission limitation above was developed by dividing the PM_{10}/$PM_{2.5}$ emission factor from AP-42, Table 1.4-2 (dated 7/98) (7.6 lb/mmscf) by the average heating value for natural gas specified in AP-42, Table 1.4-2 (dated 7/98) (1,020 Btu/scf). Compliance is presumed by only using gaseous fuels as required in C.1.(c)(1).

If required, the permittee shall demonstrate compliance with the hourly emission limitation by conducting emission testing in accordance with the methods and procedures specified in Methods 201, 201A and 202 of 40 CFR, Part 51,

Appendix M. Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA.

The annual emission limitation was established by multiplying the lb/million Btu emission limitation by the design heat input (624 million Btu/hr), then multiplying by the maximum operating schedule of 8,760 hrs/yr and dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the lb/million Btu emission limitation, compliance with the annual emission limitation shall also be demonstrated.

e. Emission Limitations:

0.0054 lb of VOC/million Btu of actual heat input and 14.74 tons of VOC/yr

Applicable Compliance Method:

The VOC emission limitation above was developed by dividing the VOC emission factor from AP-42, Table 1.4-2 (dated 7/98) (5.5 lb/mmscf) by the average heating value for natural gas specified in AP-42, Table 1.4-2 (dated 7/98) (1,020 Btu/scf). Compliance is presumed by only using gaseous fuels as required in C.1.(c)(1).

If required, the permittee shall demonstrate compliance with the hourly emission limitation by conducting emission testing in accordance with the methods and procedures specified in Methods 1 through 4, and 18, 25, or 25A, as appropriate, of 40 CFR, Part 60, Appendix A.

Use of Method 18, 25, or 25A is to be selected based on the results of a pre-survey stack sampling and U.S. EPA guidance documents. Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA.

The annual emission limitation was established by multiplying the lb/million Btu emission limitation by the design heat input (624 million Btu/hr), and then multiplying by the maximum operating schedule of 8,760 hrs/yr and dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the lb/million Btu emission limitation, compliance with the annual emission limitation shall also be demonstrated.

f. Emission Limitations:

0.03 lb NOx/million Btu of actual heat input based upon a 365-day rolling average, 0.04 lb NOx/million Btu of actual heat input based upon a 30-day rolling average, and 81.99 tons NOx/rolling, 12-month period

Applicable Compliance Method:

Ongoing compliance with the NOx emission limitation(s) shall be demonstrated through the data collected as required in the Monitoring and Recordkeeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR, Part 60.

The rolling, 12-month emission limitation was established by multiplying the 0.03 lb NOx/million Btu of actual heat input emission limitation by the maximum heat input of 624 million Btu/hr,then multiplying by the maximum annual hours of operation (8,760 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, compliance is shown using the data collected as required in the Monitoring and Record keeping Section of this permit.

g. Emission Limitations:

0.04 lb of CO/million Btu of actual heat input based upon a 365-day rolling average and 109.32 tons CO/rolling, 12-month period

Applicable Compliance Method:

The permittee shall demonstrate compliance with the lb CO/million Btu of actual heat input emission limitation by conducting emission testing pursuant to Methods 1 through 4, and 10 of 40 CFR, Part 60, Appendix A.

The rolling, 12-month emission limitation was established by multiplying the 0.04 lb CO/million Btu of actual heat input emission limitation by the maximum heat input of 624 million Btu/hr,then multiplying by the maximum annual hours of operation (8,760 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, provided compliance is shown with the lb/million Btu of actual heat input emission limitation, compliance with the rolling, 12-month period emission limitation shall also be demonstrated.

h. Emission Limitation:

67.62 tons of SO2/rolling, 12-month period

Applicable Compliance Method:

Compliance shall be based upon the fuel flow and the H2S monitoring and record keeping requirements specified in sections d)(2) through d)(5) plus a 50 ppmv allowance for non-H2S sulfur based on EPA published refinery test data, or more recent test value if future testing is performed. If required, the permittee shall determine compliance with the SO2 emission limitation by using Method 6 of 40 CFR, Part 60, Appendix A, or other U.S. EPA-approved methods.

i. Emission Limitation:

CO_2e emissions shall not exceed 330,308 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance shall be based upon the monitoring and record keeping requirements specified in section d)(13) for this emissions unit.

(2) The permittee shall conduct, or have conducted, emission testing for this emissions unit in accordance with the following requirements:

a. The emission testing shall be conducted within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of the emissions unit.

b. The emission testing shall be conducted to demonstrate compliance with the lb of CO/million Btu of actual heat input limitation.

c. The following test methods shall be employed to demonstrate compliance with the allowable CO mass emission rate: Methods 1 through 4, and 10 of 40 CFR, Part 60, Appendix A.

Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

d. The test(s) shall be conducted at a Maximum Source Operating Rate (MSOR), unless otherwise specified or approved by the Ohio EPA, Northwest District Office. MSOR is defined as the condition that is most likely to challenge the emission control measures with regards to meeting the applicable emission standard(s). Although it generally consists of operating the emissions unit at its maximum material input/production rates and results in the highest emission rate of the tested pollutant, there may be circumstances where a lower emissions loading is deemed the most challenging control scenario.

Failure to test at the MSOR is justification for not accepting the test results as a demonstration of compliance.

e. Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Ohio EPA, Northwest District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s).

Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA, Northwest District Office's refusal to accept the results of the emission test(s).

f. Personnel from the Ohio EPA, Northwest District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

g. A comprehensive written report on the results of the emissions test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA, Northwest District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA, Northwest District Office.

h. Within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup, the permittee shall conduct certification tests of the continuous NOx monitoring system in units of the applicable standard(s) to demonstrate compliance with 40 CFR, Part 60, Appendix B, Performance Specifications 2; and ORC section 3704.03(I).

Personnel from the Ohio EPA Central Office and the Ohio EPA Northwest District Office shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. Two copies of the test results shall be submitted to Ohio EPA, one copy to the Ohio EPA Northwest District Office and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification of the continuous NOx monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets the requirements of 40 CFR, Part 60, Appendix B, Performance Specifications 2; and ORC section 3704.03(I).

g) Miscellaneous Requirements

(1) None.

3. **J011, DO Railing Loading, Sulfur Loading and Caustic Unloading Rack**

Operations, Property and/or Equipment Description:

Loading rack to load out decanted oil by tank railcar, to load out sulfur from the Sulfur Recovery Unit (SRU) by railcar and to unload caustic by railcar

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(D)	1.74 tons volatile organic compounds (VOC)/rolling, 12-month period from DO Rail Loading only See b)(2)a.
b.	OAC rule 3745-31-05(A)(3), as effective 11/30/01	See b)(2)b. and b)(2)c.
c.	OAC rule 3745-31-05(A)(3), as effective 12/1/06	See b)(2)d.
d.	OAC rule 3745-21-09(T)(4)(a)	See b)(2)e. and b)(2)f.
e.	40 CFR, Part 63, Subpart CC	See b)(2)f.
f.	40 CFR, Part 63, Subpart A (40 CFR 63.1 through 63.15)	Table 6 to 40 CFR, Part 63, Subpart CC – Applicability of General Provisions to Subpart CC shows which parts of the General Provisions in 40 CFR 63.1 - 63.15 apply.

(2) Additional Terms and Conditions

a. This permit establishes the following federally enforceable emission limitation for the purpose of limiting potential to emit (PTE). The federally enforceable emission limitation is a voluntary restriction established under OAC rule 3745-31-05(D) and is based on the operational restriction contained in c)(1):

i. 1.74 tons VOC/rolling, 12-month period from DO Rail Loading only

b. Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3), as effective 11/30/01 have been determined to be compliance with OAC rule 3745-31-05(D), use of submerged fill loading of tank railcars, and compliance with the terms and conditions of this permit.

c. The permittee has satisfied the BAT requirements pursuant to OAC rule 3745-31-05(A)(3), as effective November 30, 2001, in this permit. On December 1, 2006, paragraph (A)(3) of OAC rule 3745-31-05 was revised to conform to ORC changes effective August 3, 2006 (S.B. 265 changes), such that BAT is no longer required by State regulation for NAAQS pollutant emissions less than 10 tons per year. However, that rule revision has not yet been approved by U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revision to OAC rule 3745-31-05, the requirement to satisfy BAT still exists as part of the federally-approved SIP for Ohio. Once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05, then these emission limits and control measures no longer apply.

d. This rule paragraph applies once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 as part of the State Implementation Plan.

The BAT requirements under OAC rule 3745-31-05(A)(3)(a) do not apply to the emissions of PM_{10} since the potential to emit is less than 10 tons per year, taking into account the federally enforceable restrictions established under OAC rule 3745-31-05(D) in this permit.

e. It should be noted that the requirements of OAC rule 3745-21-09(T)(4)(a) contained in the facility's alternative leak detection and repair (LDAR) program [see b)(2)f. below] have not been incorporated into Ohio's State Implementation Plan (SIP).

f. The permittee has an approved [as indicated in OAC rule 3745-21-09(T)(4)(a)] alternative leak detection and repair (LDAR) monitoring, recordkeeping and reporting program entitled "Premcor Lima Refinery, LDAR Plan" dated November 19, 2002. The permittee's alternative LDAR monitoring plan includes regulations in 40 CFR, Part 60, Subparts VV and GGG; 40 CFR, Part 61, Subpart V; and 40 CFR, Part 63, Subpart CC.

Any components associated with this emissions unit that are applicable to state and federal LDAR requirements shall be included in the alternative LDAR monitoring, recordkeeping and reporting program.

c) Operational Restrictions

(1) The following operational restriction has been included in this permit for the purpose of establishing the following federally enforceable requirements which limit PTE [See b)(2)a.]:

a. The maximum rolling, 12-month throughput of decanted oil for this emissions unit shall not exceed 76,650,000 gallons, based upon a rolling, 12-month summation of the monthly decanted oil throughput rates.

To ensure enforceability during the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the permittee shall not exceed the throughput levels specified in the following table:

Month	Maximum Allowable Cumulative Throughput (Gallons)
1	15,330,000
1-2	30,660,000
1-3	45,990,000
1-4	55,000,000
1-5	66,000,000
1-6	76,650,000
1-7	76,650,000
1-8	76,650,000
1-9	76,650,000
1-10	76,650,000
1-11	76,650,000
1-12	76,650,000

After the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, compliance with the rolling, 12-month, throughput rate limitation shall be based upon a rolling, 12-month summation of the throughput rates.

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall maintain monthly records of the following information:\

a. the throughput rate, in gallons of decanted oil loaded, for each month; and

b. beginning after the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the rolling, 12-month summation of the throughput rates.

Also, during the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the permittee shall record the cumulative throughput rate for each calendar month.

(2) Modeling to demonstrate compliance with, the "Toxic Air Contaminant Statute", ORC 3704.03(F)(4)(b), was not necessary because the emissions unit's maximum annual emissions for each toxic air contaminant, as defined in OAC rule 3745 114 01, will be less than 1.0 ton per year. OAC Chapter 3745 31 requires a permittee to apply for and obtain a new or modified permit to install prior to making a "modification" as defined by OAC rule 3745 31 01. The permittee is hereby advised that changes in the composition of the materials, or use of new materials, that would cause the emissions of any toxic air contaminant to increase to above 1.0 ton per year may require the permittee to apply for and obtain a new permit to install.

e) Reporting Requirements

(1) The permittee shall notify the Director (the Ohio EPA, Northwest District Office) on a quarterly basis, in writing, of:

a. All exceedances of the rolling, 12-month limitation on the throughput for this emissions unit; and for the first 12 calendar months of operation or the first 12 calendar months following issuance of this permit, all exceedances of the maximum allowable cumulative throughput rates.

The notification shall include a copy of the record and shall be sent to the Director (the Ohio EPA, Northwest District Office) by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during previous calendar quarters.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

1.74 tons VOC/rolling, 12-month period from DO Rail Loading only

Applicable Compliance Method:

The rolling, 12-month limitation represents the potential to emit [see b)(2)a.] based on a rolling, 12-month throughput restriction of 76,650,000 gallons of decanted oil and a loading loss emission factor of 0.045 lb VOC per 1,000 gallons loaded. The emission factor was determined in accordance with equation (1) from AP-42 Section 5.2.2.1.1(6/08). Therefore, provided compliance is shown with the rolling, 12-month throughput restriction, compliance with the rolling, 12-month period emission limitation shall also be demonstrated.

g) Miscellaneous Requirements

(1) None.

4. P005, Process

Operations, Property and/or Equipment Description:

Delayed Coking process unit including two Coker Drums (PR164237/164238) and Distillation Column (PR164903), modification including installation of new Coke Pit and addition of Front End Loader Traffic to Load Coke Product into Railcars

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-17-08(B)	See b)(2)a.
b.	OAC rule 3745-17-07(B)	See b)(2)b.
c.	OAC rule 3745-21-07(M)	See b)(2)c.
d.	OAC rule 3745-31-05(D)	The combined volatile organic compound (VOC) emissions from coke drum venting, coke cutting. and coke drum draining shall not exceed 20.81 tons/yr 18.20 tons VOC/yr from fugitive equipment leaks subject to leak detection and repair (LDAR) requirements Emissions from coke product transfer points and front-end loader traffic at the coke pit, combined: Visible fugitive particulate emissions (PE) shall not exceed 20 percent opacity as a 3-minute average; 11.66 tons fugitive PE/yr; 3.04 tons fugitive particulate matter less than or equal to 10 microns in diameter (PM_{10})/yr; and

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		0.31 ton fugitive particulate matter less than or equal to 2.5 microns in diameter ($PM_{2.5}$)/yr See b)(2)d. and b)(2)e.
e.	ORC 3704.03(T)	See b)(2)f.
f.	OAC rule 3745-31-05(A)(3), as effective 11/30/01	See b)(2)g. and b)(2)h.
g.	OAC rule 3745-31-05(A)(3), as effective 12/1/06	See b)(2)i.
h.	OAC rule 3745-31-10 through 20	Carbon dioxide equivalents (CO_2e) emissions shall not exceed 1,533 tons per rolling, 12-month period See b)(2)j.
i.	40 CFR, Part 60, Subpart A (40 CFR 60.1 – 60.19)	See 40 CFR 60.1 through 60.19
j.	OAC rule 3745-21-09(T)	See b)(2)e.
k.	40 CFR, Part 60, Subpart Ja (40 CFR 60.100a – 60.109a)	See b)(2)k.

(2) Additional Terms and Conditions

a. This facility is not located within the areas identified in "Appendix A" of OAC rule 3745-17-08 (it is located in Allen County). Therefore, the requirements of OAC rule 3745-17-08(B) do not apply to this emissions unit.

b. This emissions unit is exempt from the visible particulate emission limitations specified in OAC rule 3745-17-07(B), pursuant to OAC rule 3745-17-07(B)(11)(e).

c. This emissions unit is not subject to the requirements of the rule because it does not meet all of the conditions outlined in OAC rule 3745-21-07(M)(3)(a).

d. The permittee shall employ best available control measures that are sufficient to minimize or eliminate visible emissions of fugitive dust from coke product transfer points and front-end loader traffic at the coke pit.

The permittee shall employ best available control measures for the coke product processing/handling operations identified below, for the purpose of ensuring compliance with the applicable PM_{10} requirements presented in b)(1)a.

In accordance with the permit application, the permittee has committed to perform the following control measure(s) when the unit is in operation to ensure compliance:

Coke Product Processing and Handling Operation	**Control Measure(s)**
Coke product drop - coker unit into coke pit	Inherently wet coke product from saturation during removal
Removal of coke product from coke pit with front-end loader	Inherently wet coke product from saturation (apply water if necessary)
Fugitive dust from front-end loader traffic on unpaved roadways	Apply dust suppressant as necessary

Nothing in the table above shall prohibit the permittee from employing other equally-effective control measures to ensure compliance.

e. The Coker process unit is not subject to leak detection and repair (LDAR) requirements in 40 CFR, Part 60, Subpart GGGa (Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced after November 7, 2006), since it does not meet the definition of "modification" in 40 CFR 60.590a.

New and modified piping components associated with this emissions unit are subject to the appropriate provisions (including operational restrictions, monitoring and record keeping, reporting, and testing) of OAC rule 3745-21-09(T) – Leaks from petroleum refinery equipment.

The requirements of these rules are equivalent to or less stringent than the alternative LDAR monitoring plan submitted by the permittee, pursuant to OAC rule 3745-21-09(T)(4) and 40 CFR, Part 63, Subpart CC. Terms and conditions for the alternative LDAR plan are listed in section B.2 of the Facility-Wide Terms and Conditions of the facility's renewal Title V with effective date of 3/26/13.

f. Best Available Technology (BAT) requirements for VOC emissions under ORC 3704.03(T) have been determined to be compliance with OAC rule 3745-31-05(D).

g. BAT requirements for PM_{10} emissions under OAC rule 3745-31-05(A)(3), as effective 11/30/01 have been determined to be compliance with OAC rule 3745-31-05(D) and compliance with the terms and conditions of this permit.

h. The permittee has satisfied the BAT requirements for PM_{10} emissions pursuant to OAC rule 3745-31-05(A)(3), as effective November 30, 2001, in this permit. On December 1, 2006, paragraph (A)(3) of OAC rule 3745-31-05 was revised to conform to ORC changes effective August 3, 2006 (S.B. 265 changes), such that BAT is no longer required by State regulation for NAAQS pollutant emissions less than 10 tons per year. However, that rule revision has not yet been approved by U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revision to OAC rule 3745-31-05, the requirement to satisfy BAT still exists as part of the federally-approved SIP for Ohio. Once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05, then these emission limits and control measures no longer apply.

i. This rule paragraph applies once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 as part of the State Implementation Plan.

The BAT requirements under OAC rule 3745-31-05(A)(3)(a) do not apply to the emissions of PM_{10} since the potential to emit is less than 10 tons per year.

j. The permittee shall employ Best Available Control Technology (BACT) for this emissions unit. BACT has been determined to be the following:

Pollutant	BACT Requirements
GHG	The permittee shall depressurize each coke drum to 5 pounds per square inch gage (psig) or less prior to venting the coke drum steam exhaust to the atmosphere. When the pressure exceeds 5 psig, vent gases must be routed to the refinery fuel gas system, the FCC/coker flare (emissions unit P006), or other control device prior to opening the vent to the atmosphere.

k. Compliance with condition b)(2)j. above demonstrates compliance with the requirements of 40 CFR, Part 60, Subpart Ja.

c) Operational Restrictions

(1) None.

d) Monitoring and/or Recordkeeping Requirements

(1) Except as otherwise provided in this section, for coke product handling operations that are not adequately enclosed, the permittee shall perform visible emission inspections of such operations during representative, normal operating conditions in accordance with the following minimum frequencies:

Coke Product Processing and Handling Operation	Minimum Inspection Frequency
Removal of coke product from coke pit with front-end loader	Once per day of operation
Fugitive dust from front-end loader traffic on unpaved roadways	Once per day of operation

(2) The permittee shall maintain daily records of the following information:

a. the date and reason any required inspection was not performed;

b. the date of each inspection where it was determined by the permittee that it was necessary to implement the control measure(s);

c. the dates the control measure(s) was (were) implemented; and

d. on a calendar quarter basis, the total number of days the control measure(s) was (were) implemented.

The information in d)(2)d. shall be kept separately for each coke product processing/handling operation identified above, and shall be updated on a calendar quarter basis within 30 days after the end of each calendar quarter.

(3) The permittee shall record the pressure inside the coke drum prior to discharging the coke drum to the atmosphere.

e) Reporting Requirements

(1) The permittee shall submit deviation reports that identify any of the following occurrences:

a. each day during which an inspection was not performed by the required frequency, excluding an inspection which was not performed due to an exemption for snow and/or ice cover or precipitation;

b. each instance when a control measure, that was to be implemented as a result of an inspection, was not implemented; and

c. all periods when the blow down vent vapors were vented to the atmosphere without first depressuring the coke drum to less than 5.0 psig; and the actual coke drum pressure prior to venting, for each such event.

The deviation reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

The combined VOC emissions from coke drum venting, coke cutting.and coke drum draining shall not exceed 20.81 tons/yr

Applicable Compliance Method:

The permittee shall demonstrate compliance by multiplying the maximum number of 730 coke producing cycles/yr* by an emission factor of 57 lbs VOC/cycle, then dividing by 2,000 lbs/ton. The emission factor was determined in accordance with Table 5-5, "Average Vent Concentrations and Emission Factors for Delayed Coking Unit Vents – Emission Estimation Protocol for Petroleum Refineries, U.S. EPA, Version 2.1.1 (5/11).

* 730 coke producing cycles/yr represents the potential to emit for this emissions unit

b. Emission Limitation:

18.20 tons VOC/yr from fugitive equipment leaks subject to LDAR requirements

Applicable Compliance Method:

Compliance with the annual fugitive VOC emissions limitation is demonstrated by compliance with the applicable leak monitoring and repair requirements of 40 CFR, Part 60, Subpart GGG and 40 CFR, Part 63, Subpart CC. The annual fugitive VOC emission limitation was established for PTI purposes to reflect the maximum potential to emit (PTE) for this emissions unit. Therefore, it is not necessary to develop any further monitoring, record keeping and/or reporting requirements to ensure compliance with this limitation.

c. Emission Limitation:

Visible PE shall not exceed 20 percent opacity as a 3-minute average from coke product transfer points and front-end loader traffic at the coke pit

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance with the visible particulate emission limitation above in accordance with the methods and procedures specified in Method 9 of 40 CFR, Part 60, Appendix A.

d. Emission Limitation:

11.66 tons PE/yr from coke product transfer points and front-end loader traffic at the coke pit, combined

Applicable Compliance Method:

The emission limitation was established using the following emission factors:

i. 0.0014 lb PE/ton of coke product for all coke product transfer points - Equation (1) in AP-42, section 13.2.4.3 for drop operations (11/06) multiplied by the maximum amount of coke handled of 370,840 tons/yr*, then dividing by 2,000 lbs/ton; and

ii. 9.28 lbs PE/vehicle mile traveled by front-end loader – Equation (1a) in AP-42, section 13.2.2 (11/06) and based on 182 vehicle trips per day**, 1,300 feet/trip, applying a control efficiency of 85% for inherent moisture in the coke product; and use of various constants in Tables 13.2.2-2 and 13.2.4-1 in AP-42 (11/06).

* 370,840 tons of coke handled/yr represent the potential to emit for this emissions unit

**182 vehicle trips per day represent the potential to emit for this emissions unit

Therefore, provided compliance is shown with the requirements to employ the best available control measures, compliance with the annual emission limitation shall also be demonstrated.

e. Emission Limitation:

3.04 tons PM_{10}/yr from transfer points and front-end loader traffic at the coke pit, combined

Applicable Compliance Method:

The emission limitation was established using the following emission factors:

i. 0.0007 lb PM_{10}/ton of coke product for all coke product transfer points - Equation (1) in AP-42, section 13.2.4.3 for drop operations (11/06) multiplied by the maximum amount of coke handled of 370,840 tons/yr*, then dividing by 2,000 lbs/ton; and

ii. 2.38 lbs PM_{10}/vehicle mile traveled by front-end loader – Equation (1a) in AP-42, section 13.2.2 (11/06) and based on 182 vehicle trips per day*, 1,300 feet/trip, applying a control efficiency of 85% for inherent moisture in the coke product; and use of various constants in Tables 13.2.2-2 and 13.2.4-1 in AP-42 (11/06).

* 370,840 tons of coke handled/yr represents the potential to emit for this emissions unit

**182 vehicle trips per day represent the potential to emit for this emissions unit

Therefore, provided compliance is shown with the requirements to employ the best available control measures, compliance with the annual emission limitation shall also be demonstrated.

f. Emission Limitation:

0.31 tons $PM_{2.5}$/yr from transfer points and front-end loader traffic at the coke pit, combined

Applicable Compliance Method:

The emission limitation was established using the following emission factors:

i. 0.0001 lb $PM_{2.5}$/ton of coke product for all coke product transfer points - Equation (1) in AP-42, section 13.2.4.3 for drop operations (11/06) multiplied by the maximum amount of coke handled of 370,840 tons/yr*, then dividing by 2,000 lbs/ton; and

ii. 0.24 lbs $PM_{2.5}$/vehicle mile traveled by front-end loader – Equation (1a) in AP-42, section 13.2.2 (11/06) and based on 182 vehicle trips per day*, 1,300 feet/trip, applying a control efficiency of 85% for inherent moisture in the coke product; and use of various constants in Tables 13.2.2-2 and 13.2.4-1 in AP-42 (11/06).

* 370,840 tons of coke handled/yr represents the potential to emit for this emissions unit

**182 vehicle trips per day represent the potential to emit for this emissions unit

Therefore, provided compliance is shown with the requirements to employ the best available control measures, compliance with the annual emission limitation shall also be demonstrated.

g. Emission Limitation:

CO_2e emissions shall not exceed 1,533 tons per rolling, 12-month period

Applicable Compliance Method:

The allowable CO_2e emissions limitation was established to reflect the potential to emit for this emissions unit based on an emission factor (200 lbs methane/coke producing cycle) derived from Table 5-5, "Average Vent Concentrations and Emission Factors for Delayed Coking Unit Vents – Emission Estimation Protocol for Petroleum Refineries, U.S. EPA, Version 2.1.1 (5/11) multiplied by the global warming potential of methane (21 CO2e/methane), and by the maximum number of coke producing cycles of 730 per year, and then dividing by 2,000 lbs/ton.

g) Miscellaneous Requirements

(1) None.

5. P037, LIU Cooling Tower

Operations, Property and/or Equipment Description:

Modification of existing LIU cooling tower to include installation of a new high efficiency drift eliminator

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(D)	13.63 lbs particulate emissions (PE)/hr and 59.68 tons PE/yr 9.54 lbs particulate matter less than or equal to 10 microns in diameter (PM_{10})/hr and 41.78 tons PM_{10}/yr 5.72 lbs particulate matter less than or equal to 2.5 microns in diameter ($PM_{2.5}$)/hr and 25.07 tons $PM_{2.5}$/yr 3.40 lbs volatile organic compounds (VOC)/hr and 14.90 tons VOC/yr See b)(2)a.
b.	ORC 3704.03(T)	See b)(2)b.
c.	OAC rule 3745-17-11(B)	See b)(2)c.
d.	OAC rule 3745-17-07(A)	Visible PE shall not exceed 20% opacity, as a 6-minute average, except as provided by the rule.
e.	40 CFR, Part 63, Subpart CC	See b)(2)d.
f.	40 CFR 63.1 through 63.15	Table 6 to 40 CFR, Part 63, Subpart CC – Applicability of General Provisions to Subpart CC shows which parts of the General Provisions in 40 CFR 63.1 – 63.15 apply.

(2) Additional Terms and Conditions

a. This permit establishes the following federally enforceable emissions limitations for the purpose of limiting potential to emit (PTE). The federally enforceable emissions limitations are voluntary restrictions established under OAC rule 3745-31-05(D) and are based on the operational restrictions contained in c)(1):

i. 13.63 lbs PE/hr and 59.68 tons PE/yr;

ii. 9.54 lbs PM_{10}/hr and 41.78 tons PM_{10}/yr;

iii. 5.72 lbs $PM_{2.5}$/hr and 25.07 tons $PM_{2.5}$/yr; and

iv. 3.40 lbs VOC/hr and 14.90 tons VOC/yr.

b. The BAT requirements under ORC 3704.03(T) for PE, PM_{10}, $PM_{2.5}$ and VOC have been determined to be compliance with OAC rule 3745-31-05(D).

c. The PE limitation specified by this rule [using Table 1 of OAC rule 3745-17-11(B)] is less stringent than the PE limitation established pursuant to OAC rule 3745-31-05(D).

d. This emissions unit is subject to the heat exchanger requirements in 40 CFR 63.654.

c) Operational Restrictions

(1) The following operational restrictions have been included in this permit for the purpose of establishing the following federally enforceable requirements which limit PTE [See b)(2)a.]:

a. The permittee shall not exceed a total dissolved solids (TDS) content of 5,600 mg/l (as a monthly average) in the cooling water for this emissions unit; and

b. Use of a high efficiency drift eliminator designed to achieve a drift rate of 0.006 percent.

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall test and record the TDS content, in ppm, of the cooling water at least once per month. The TDS content shall be measured using test procedures that conform to regulation 40 CFR, Part 136, "Test Procedures for the Analysis of Pollutants" or an equivalent method approved by the Ohio EPA, Northwest District Office.

(2) Perform monitoring to identify leaks of total strippable volatile organic compounds (VOC) from each heat exchange system subject to the requirements in 40 CFR 63.654 according to the procedures in paragraphs (c)(1) through (6) of 63.654.

(3) Each month, the permittee shall calculate and record the PE, in lbs per hr. The PE shall be calculated as follows:

[(81,000 gallons/minute) x (ppm TDS) x (0.00006) x (60 min/hr) x (0.0584)]/(7,000 grains/lb) = PE, in lbs/hr

Where:

81,000 gallons/minute = the maximum water flow rate;

ppm TDS = the TDS level, on a monthly average basis, if more than one measurement is taken in a month;

0.00006 = the maximum drift loss factor;

60 min/hr = conversion factor for minutes to hours;

0.0584 = conversion factor for ppm to grains/gallon; and

7,000 gr/lb = conversion factor for grains to pounds.

(4) Each month, the permittee shall calculate and record the PM_{10}, in lbs per hr. The PM_{10} shall be calculated as follows:

[(81,000 gallons/minute) x (ppm TDS) x (0.00006) x (60 min/hr) x (0.0584)]/(7,000 grains/lb) x 0.70 = PM_{10}, in lbs/hr

where:

81,000 gallons/minute = the maximum water flow rate;

ppm TDS = the TDS level, on a monthly average basis, if more than one measurement is taken in a month;

0.00006 = the maximum drift loss factor;

60 min/hr = conversion factor for minutes to hours;

0.0584 = conversion factor for ppm to grains/gallon;

7,000 gr/lb = conversion factor for grains to pounds; and

0.70 = PM_{10} is 70 percent of total PE, based on California Emissions Inventory Development and Reporting System

(5) Each month, the permittee shall calculate and record the $PM_{2.5}$, in lbs per hr. The $PM_{2.5}$ shall be calculated as follows:

[(81,000 gallons/minute) x (ppm TDS) x (0.00006) x (60 min/hr) x (0.0584)]/(7,000 grains/lb) x 0.42 = $PM_{2.5}$, in lbs/hr where:

81,000 gallons/minute = the maximum water flow rate;

ppm TDS = the TDS level, on a monthly average basis, if more than one measurement is taken in a month;

0.00006 = the maximum drift loss factor;

60 min/hr = conversion factor for minutes to hours;

0.0584 = conversion factor for ppm to grains/gallon;

7,000 gr/lb = conversion factor for grains to pounds; and

0.42 = PM_{10} is 42 percent of total PE, based on California Emissions Inventory Development and Reporting System

(6) Each month, the permittee shall calculate and record the calendar year to date emissions of PE, PM_{10} and $PM_{2.5}$, in tons.

(7) If a leak is detected, during the monitoring performed per d)(2) above, repair the leak to reduce the measured concentration to below the applicable action level as soon as practicable, but no later than 45 days after identifying the leak, except as specified in paragraphs 40 CFR 63.654(e) and (f). Repair includes re-monitoring at the monitoring location where the leak was identified according to the method specified in paragraph 40 CFR 63.654(c)(3) to verify that the measured concentration is below the applicable action level.

e) Reporting Requirements

(1) The permittee shall notify the Director (the Ohio EPA, Northwest District Office) on a quarterly basis, in writing, of:

a. All exceedances of the TDS content restriction of 5,600 mg/l; and

b. All exceedances of the hourly allowable mass emission limitations for PE, PM_{10} and $PM_{2.5}$.

The notification shall include a copy of the record and shall be sent to the Director (the Ohio EPA, Northwest District Office) by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during previous calendar quarters.

(3) Comply with the reporting requirements for heat exchange systems subject to 40 CFR 63.654 requirements in 40 CFR 63.655.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitations:

13.63 lbs PE/hr and 59.68 tons PE/yr

Applicable Compliance Method:

Compliance with hourly emission limitation shall be demonstrated by the monitoring and record keeping requirements specified in sections d)(1) and d)(2) of these terms and conditions.

If required, the permittee shall conduct drift measurement testing to determine the drift factor for this cooling tower utilizing the "Isokinetic Drift Measurement Test Code for Water Cooling Towers", ATC-140(94), June, 1994 (or the most recent edition) from the Cooling Technology Institute.

The annual emission limitation was established by multiplying the hourly emission limitation by the maximum operating schedule of 8,760 hrs/yr and then dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the TDS content operational restriction in section c)(1)a. and the hourly emission limitation, compliance with the annual emission limitation shall also be demonstrated.

b. Emission Limitations:

9.54 lbs PM_{10}/hr and 41.78 tons PM_{10}/yr

Applicable Compliance Method:

Compliance with the hourly emission limitation shall be demonstrated by the monitoring and record keeping requirements specified in sections d)(1) and d)(3) of these terms and conditions.

If required, the permittee shall conduct drift measurement testing to determine the drift factor for this cooling tower utilizing the "Isokinetic Drift Measurement Test Code for Water Cooling Towers", ATC-140(94), June, 1994 (or the most recent edition) from the Cooling Technology Institute.

The annual emission limitation was established by multiplying the hourly emission limitation by the maximum operating schedule of 8,760 hrs/yr, and then dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the TDS content operational restriction in section c)(1)a. and the hourly emission limitation, compliance with the annual emission limitation shall also be demonstrated.

c. Emission Limitations:

5.72 lbs $PM_{2.5}$/hr and 25.07 tons $PM_{2.5}$/yr

Applicable Compliance Method:

Compliance with the hourly emission limitation shall be demonstrated by the monitoring and record keeping requirements specified in sections d)(1) and d)(4) of these terms and conditions.

If required, the permittee shall conduct drift measurement testing to determine the drift factor for this cooling tower utilizing the "Isokinetic Drift Measurement Test Code for Water Cooling Towers", ATC-140(94), June, 1994 (or the most recent edition) from the Cooling Technology Institute.

The annual emission limitation was established by multiplying the hourly emission limitation by the maximum operating schedule of 8,760 hrs/yr, and then dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the TDS content operational restriction in section c)(1)a. and the hourly emission limitation, compliance with the annual emission limitation shall also be demonstrated.

d. Emission Limitations:

3.40 lbs VOC/hr and 14.90 tons VOC/yr

Applicable Compliance Method:

The permittee shall demonstrate compliance with the hourly limitation by multiplying the appropriate VOC emission factor of 0.7 pounds per million gallons of flow, from AP-42 Table 5.1-2 (1/95), by the maximum flow of 4,860,000 gallons per hour.

The annual emission limitation was established by multiplying the hourly emission limitation times the maximum operating schedule of 8,760 hrs/yr and dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the hourly emission limitation, compliance with the annual emission limitation shall also be demonstrated.

e. Emission Limitation:

Visible PE shall not exceed 20% opacity, as a 6-minute average, except as provided by the rule.

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance with the visible PE limitation above in accordance with the methods and procedures specified in Method 9 of 40 CFR, Part 60, Appendix A; and the requirements specified in OAC rule 3745-17-03(B)(1).

g) Miscellaneous Requirements

(1) None.

6. P040, Sulfur Recovery Units 1 and 2

Operations, Property and/or Equipment Description:

Modification of Sulfur Recovery Unit Claus 1 and Claus 2 Units to add oxygen enrichment and increase production to 160 long tons per day, combined capacity

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(D)	Combustion emissions from the tail gas incinerator shall not exceed the following: 0.14 lb of particulate emissions/ particulate matter less than or equal to 10 microns in diameter/particulate matter less than or equal to 2.5 microns in diameter ($PE/PM_{10}/PM_{2.5}$)//hr and 0.61 ton of $PE/PM_{10}/PM_{2.5}$/yr 0.10 lb of volatile organic compounds (VOC)/hr and 0.44 ton of VOC/yr. Visible PE shall not exceed 20% opacity, as a six-minute average. See b)(2)a. through b)(2)d.
b.	ORC 3704.03(T)	See b)(2)e.
c.	OAC rule 3745-31-05(A)(3), as effective 11/30/01	See b)(2)f. and b)(2)g.
d.	OAC rule 3745-31-05(A)(3), as effective 12/1/06	See b)(2)h.
e.	OAC rule 3745-31-10 through 3745-31-20	Combustion emissions from the tail gas incinerator shall not exceed the following: 1.84 lbs of nitrogen oxides (NOx)/hr and 8.06 tons of NOx/rolling, 12-month period

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		1.88 lbs of carbon monoxide (CO)/hr and 8.23 tons of CO/rolling, 12-month period Carbon dioxide equivalents (CO_2e) emissions shall not exceed 33,241 tons per rolling, 12-month period Process emissions from the tail gas incinerator shall not exceed the following: 19.18 lbs of sulfur dioxide (SO2)/hr, as a 12-hr rolling average; 84.02 tons of SO2/rolling, 12-month period; and 250 parts per million by volume (dry basis) of SO2 at 0% excess air as a 12-hour rolling average See b)(2)i.
f.	40 CFR, Part 63, Subpart CC [40 CFR 63.640 – 63.656] [In accordance with 40 CFR 63.640, the rich amine flash drum that is part of this emissions unit is an affected source since it contains a Group 1 process vent that is routed to either the FCC/Coker flare (emissions unit P006) or the LIU flare (emissions unit P007)]	See b)(2)l., b)(2)m. and e)(4)
g.	40 CFR, Part 63, Subpart UUU [40 CFR 63.1560 – 63.1579] accordance with 40 CFR 63.1562, this emissions unit is an affected source consisting of process vent or group of process vents on the two Claus sulfur recovery plant units and the tail gas treatment unit serving the sulfur recovery plant, that are associated with sulfur recovery, including any bypass line(s), subject to the emission limitations/control measures specified in this section.]	See b)(2)n., d)(5) , e)(5) , and f)(2)
h.	40 CFR, Part 60, Subpart Ja 40 CFR 60.102a(f)(1) and Subpart J 40 CFR 60.104(a)(2)(i)	250 parts per million by volume (dry basis) of SO2 at 0% excess air as a 12-hour rolling average

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
i.	OAC rule 3745-21-09(T)	leaks from petroleum refinery equipment [See b)(2)o.]
j.	OAC rule 3745-21-09(DD)	leaks from petroleum refinery equipment [See b)(2)o.]
k.	40 CFR, Part 60, Subpart VV	leaks from petroleum refinery equipment [See b)(2)o.]
l.	40 CFR, Part 60, Subpart GGG	leaks from petroleum refinery equipment [See b)(2)o.]
m.	40 CFR, Part 60, Subpart A	See 40 CFR 60.1 through 60.19
n.	40 CFR, Part 61, Subpart V	leaks from petroleum refinery equipment [See b)(2)o.]
o.	OAC rule 3745-18-08(C)(3)	100 lbs SO2/1,000 lbs of sulfur processed [See b)(2)b.]
p.	OAC rule 3745-17-11(B)(1)	None [See b)(2)j.]
q.	OAC rule 3745-17-07(A)	None [See b)(2)k.]
r.	40 CFR, Part 61, Subpart FF [40 CFR 61.340 – 61.358] [In accordance with 40 CFR 61.340, the sour water components of this emissions unit are an affected source since processing of wastewater containing benzene occurs.]	See b)(2)p.
s.	40 CFR, Part 61, Subpart A	See 40 CFR 61.01 through 61.19
t.	40 CFR 63.1 through 63.15	Table 6 to 40 CFR, Part 63, Subpart CC – Applicability of General Provisions to Subpart CC shows which parts of the General Provisions in 40 CFR 63.1 - 63.15 apply. Table 44 to 40 CFR, Part 63, Subpart UUU – Applicability of General Provisions to Subpart UUU shows which parts of the General Provisions in 40 CFR 63.1 - 63.15 apply.
u.	40 CFR, Part 60, Subpart J [In accordance with 40 CFR 60.101(g), the tail gas incinerator is considered a fuel gas combustion device due to the combustion of the BB Treater spent air stream, Ohio EPA emissions unit P041.]	See 40 CFR 60.104(a)(1), 60.105(a)(4)(iv) and 60.105(b) See b)(2)q.

(2) Additional Terms and Conditions

a. Federal consent decree addendum, civil action No. SA07CA0683RF which became effective on November 20, 2007, requires the reduction of SO2 at the Lima Refining Company by requiring that all heaters and boilers be affected facilities and subject to the applicable fuel gas combustion requirements of 40 CFR, Part 60, Subpart J.

Emissions unit P040 consists of two sulfur recovery units (Claus Unit 1 and Claus Unit 2) which operate in a parallel configuration with the tail gas from each unit being routed to a common tail gas treating unit and incinerator. Claus Units 1 and 2 receive acid gas from the "Lima Integrated Unit" (LIU) amine treatment system, historical Ohio EPA emissions unit P002.

The LIU amine treatment system treats the sour gas generated by various LIU process units and provides this treated fuel gas to heaters located on the LIU units. In order for heaters and boilers served by the LIU fuel gas system to meet the fuel gas combustion requirements of 40 CFR, Part 60, Subpart J, the LIU amine treatment system must be upgraded. The upgrade to the amine treatment system does not constitute a modification as defined in OAC rule 3745-31-01 based on PTI No. 03-13794, issued on 5/29/08 [see b)(2)b. for additional details].

This permit action is being issued as requested by the permittee to address any activities associated with the upgrade to the LIU amine treatment system that could be considered applicable to new source review requirements. It should be noted that this permit is virtually identical in requirements to those contained in PTI No. 03-13794 issued on 5/29/08.

b. Emissions unit P040 was established in PTI No. 03-13794, issued on 5/29/08, as a consolidation of three existing emissions units (P002, P011, and P015) which comprised an existing sulfur recovery unit/system at the facility.

The consolidation was granted by Ohio EPA as requested by the permittee due to modifications which resulted in the sulfur recovery unit/system having one common egress point of emissions, the exhaust stack for the tail gas incinerator. It should be noted that the consolidation resulting in the establishment of P040 does not remove the applicability of OAC rule 3745-18-08. Because P040 is simply a grouping of P002, P011 and P015, it will continue to be subject to OAC rule 3745-18-08. In addition, this common egress point will include a spent air stream from the new Butane-Butylene Treater (emissions unit P041) which is routed to the oxidation chamber of the tail gas incinerator. Therefore, all the above emission limits are combined for these emissions units (P040 and P041). Requirements for Emissions unit P041 were established in PTI No. 03-13794, issued 5/29/08.

The OAC rule 3745-18-08 SO2 limit of 100 lbs SO2/1,000 lbs sulfur processed is less stringent than the limit established under OAC rule 3745-31-10 through 3745-31-20 and 40 CFR, Part 60, Subpart Ja. Compliance with this limit will be demonstrated through compliance with OAC rule 3745-31-10 through 31-20 and NSPS Ja.

c. It is assumed that all PE are equivalent to both PM_{10} and $PM_{2.5.}$

d. This permit establishes the following federally enforceable emission limitations for the purpose of representing the potentials to emit of the emissions unit:

i. 0.14 lb of PE/PM_{10}/$PM_{2.5}$/hr and 0.61 ton of PE/PM_{10}/$PM_{2.5}$/yr; and

ii. 0.10 lb of VOC/hr and 0.44 ton of VOC/yr.

e. Best Available Technology (BAT) requirements for SO2 emissions under ORC 3704.03(T) have been determined to be compliance with OAC rule 3745-31-10 through 3745-31-20.

f. Best Available Technology (BAT) requirements for PM_{10}, VOC, NOx and CO under OAC rule 3745-31-05(A)(3), as effective 11/30/01 have been determined to be compliance with OAC rule 3745-31-05(D) and OAC rule 3745-31-10 through 3745-31-20, and compliance with the terms and conditions of this permit.

g. The permittee has satisfied the BAT requirements pursuant to OAC rule 3745-31-05(A)(3), as effective November 30, 2001, in this permit. On December 1, 2006, paragraph (A)(3) of OAC rule 3745-31-05 was revised to conform to ORC changes effective August 3, 2006 (S.B. 265 changes), such that BAT is no longer required by State regulation for NAAQS pollutant emissions less than 10 tons per year. However, that rule revision has not yet been approved by U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revision to OAC rule 3745-31-05, the requirement to satisfy BAT still exists as part of the federally-approved SIP for Ohio. Once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05, then these emission limits and control measures no longer apply.

h. This rule paragraph applies once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 as part of the State Implementation Plan.

The BAT requirements under OAC rule 3745-31-05(A)(3)(a) do not apply to the emissions of PM_{10}, VOC, NOx and CO since the potential to emit is less than 10 tons per year.

i. The permittee shall employ Best Available Control Technology (BACT) for this emissions unit. BACT has been determined to be the following:

Pollutant	BACT Requirements
NOx	1.84 lbs of nitrogen oxides (NOx)/hr; and Use of good combustion practices.

SO2	Compliance with 40 CFR, Part 60, Subpart Ja; 19.18 lbs of sulfur dioxide (SO2)/hr, as a 12-hr average; 250 parts per million by volume (dry basis) of SO2 at 0% excess air as a 12-hour average; and Use of a tail gas treatment unit and tail gas incinerator.
CO	1.88 lbs of CO/hr; and Use of good combustion practices.
CO_2e	Use of low-carbon gaseous fuel (natural gas)

j. The uncontrolled mass rate of PE* from this emissions unit is less than 10 pounds/hour. Therefore, pursuant to OAC rule 3745-17-11(A)(2)(a)(ii), Figure II of OAC rule 3745-17-11 does not apply. In addition, Table I of OAC rule 3745-17-11 does not apply because the process weight rate is equal to zero. "Process weight" is defined in OAC rule 3745-17-01(B)(14).

* The burning of gaseous fuels is the only source of PE from this emissions unit

k. This emissions unit is exempt from the visible PE limitations specified in OAC rule 3745-17-07(A) pursuant to OAC rule 3745-17-07(A)(3)(h) because the emissions unit is not subject to the requirements of OAC rule 3745-17-11.

l. Pursuant to the Group 1 miscellaneous process vent requirements in 40 CFR 63.641, the permittee shall reduce emissions of organic HAP's using a flare(s) that meets the requirements of 40 CFR 63.11(b) of subpart A for emissions from the rich amine flash drum.

m. MACT requirements in 40 CFR, Part 63, Subpart CC are applicable for the Group 1 process vent that is part of this emissions unit, the rich amine flash drum, and is routed to either emissions unit P006 and/or P007, the FCC/Coker flare or LIU flare, respectively.

The permittee shall comply with the applicable control requirements, emission limit and compliance demonstration methods under 40 CFR, Part 63, Subpart CC, including the following sections:

63.643(a)(1)	Required Use of Flare to Reduce Organic Hazardous Air Pollutants

n. The permittee shall comply with the applicable control requirements, operating limits, emission limits and work practice standards under 40 CFR, Part 63, Subpart UUU, including the following sections:

63.1568(a)(1) and Table 29	Sulfur Dioxide (SO2) Emission Limit for New Source Performance Standard Units: Meet Option A – 250 parts per million by volume (dry basis) of SO2 at 0% excess air (use of oxidation or reduction control system followed by incineration)
63.1568(a)(3)	Prepare Operation, Maintenance and Monitoring Plan
63.1570(a)	Compliance with Non-opacity Standards
63.1570(g)	Deviations during Startup, Shutdown or Malfunction

o. This emissions unit is subject to the appropriate provisions (including operational restrictions, monitoring and record keeping, reporting, and testing) of OAC rule 3745-21-09(T) – Leaks from petroleum refinery equipment, OAC rule 3745-21-09(DD) – Leaks from process units that produce organic chemicals, 40 CFR, Part 60, Subpart VV (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry), 40 CFR, Part 60, Subpart GGG (Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, 40 CFR, Part 63, Subpart CC (Petroleum Refinery MACT Standards), and 40 CFR, Part 61, Subpart V (National Emission Standard for Equipment Leaks – Fugitive Emission Sources).

The requirements of these rules are equivalent to or less stringent than the alternative leak detection and repair (LDAR) monitoring plan submitted by the permittee, pursuant to OAC rule 3745-21-09(T)(4) and 40 CFR, Part 63, Subpart CC. Terms and conditions for the alternative LDAR plan are listed in section B.2 of the Facility-Wide Terms and Conditions of the Title V renewal permit.

p. The permittee shall include the sour water components of this emissions unit, SRU 1 & 2, in the current site benzene waste operations program.

q. NSPS requirements for fuel gas combustion devices at 40 CFR 60.104(a)(1) are applicable to the tail gas incinerator. The tail gas incinerator is considered a fuel gas combustion device per 40 CFR 60.101(h) due to the combustion of the BB treater spent air stream (Ohio EPA emissions unit P041.)

As this stream has been previously demonstrated to be inherently low in sulfur content, this stream is exempt from the monitoring requirements of 60.105(a)(4), per 60.105(a)(4)(iv)(d). Details are provided in the written application submitted to Ohio EPA on 11/3/2009, company file #A14-09-46, in accordance with 60.105(b).

A fuel gas stream that is determined to be low-sulfur is exempt from the monitoring requirements of 60.105(a)(3) and (4) until there are changes in the operating conditions or stream composition.

No further action is required outside of the written application request in accordance with 40 CFR Part 60.105(b)(3) unless refinery operating conditions change in a way that would affect the composition of the exempt fuel gas stream.

c) Operational Restrictions

(1) None.

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall operate and maintain equipment to continuously monitor and record SO2from this emissions unit in units of the applicable standard. The span value of the continuous emission monitoring system (CEMS) shall be 500 ppm SO2. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR, Part 60.13.

The permittee shall maintain records of all data obtained by the continuous SO2monitoring system including, but not limited to, parts per million of SO2for each cycle time of the analyzer, with no resolution less than one data point per minute required, and lbs/hr of SO2, as a 12-hr average; results of daily zero/span calibration checks, and the magnitudes of manual calibration adjustments.

The permittee shall maintain a written quality assurance/quality control (QA/QC) plan for the SO2CEMS that follows the requirements of 40 CFR, Part 60, Appendix F. The QA/QC plan and logbook for the SO2CEMS must be kept on site and available for inspection during regular office hours.

(2) The permittee shall operate and maintain equipment to continuously monitor and record the oxygen (O2) from this emissions unit in percent O2. The span value of the CEMS shall be 25 percent O2. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR, Part 60.13 or as approved by the Ohio EPA, Central Office.

The permittee shall maintain records of all data obtained by the continuous O2monitoring system including, but not limited to percent O2for each cycle time of the analyzer, with no resolution less than one data point per minute required, results of daily zero/span calibration checks, and magnitude of manual calibration adjustments.

The permittee shall maintain a quality assurance/quality control plan for the continuous O2monitoring system designed to ensure continuous valid and representative readings. The plan shall follow the requirements of 40 CFR, Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the continuous O2system must be kept on site and available for inspection during regular office hours.

(3) The permittee shall maintain daily records of the following information for this emissions unit:

i. the total amount of sulfur processed; and

j. the total SO2emissions, in lbs.

For a specific period of time, the amount of sulfur processed is equal to the amount of sulfur entering the Claus units plus the amount of any sulfur bypassed to the flare(s) from the amine units and/or the sour water stripper, except for periods of start-up, shutdown, or malfunction as defined in 40 CFR 60.2.

(4) The permittee shall include the SRU fugitive emissions and associated components in the current site fugitive leak detection and repair (LDAR) program. The LDAR program shall be conducted in accordance with the alternative monitoring plan submitted by the permittee. Applicable requirements are listed in section B.2 of the Facility-Wide Terms and Conditions of the facility's renewal Title V with effective date of 3/26/13.

(5) The permittee shall comply with the applicable monitoring and recordkeeping requirements under 40 CFR, Part 63, Subpart UUU, including the following sections:

63.1568(b)(1) and Table 31	Install, Operate and Maintain Sulfur Dioxide Continuous Emission Monitor
63.1568(c)(1), Table 34 and Table 35	Continuous Compliance - Sulfur Dioxide Continuous Emission Monitor
63.1568(c)(2)	Continuous Compliance with Operation, Maintenance and Monitoring Plan
63.1570(c)	General Duty – Log Prior to Continuous Monitoring System Validation
63.1572(a)(1), 63.1572(a)(3), 63.1572(a)(4), 63.1572(d)(1), 63.1572(d)(2) and Table 40	Sulfur Dioxide Continuous Emission Monitor Requirements
63.1574(f)(2)(i), 63.1574(f)(2)(ii), and 63.1574(f)(2)(viii) through 63.1574(f)(2)(x)	Operation, Maintenance and Monitoring Plan Requirements
63.1576(a)(1), 63.1576(a)(2), 63.1576(b)(1) through 63.1576(b)(5), 63.1576(d) through 63.1576(i), Table 34 and Table 35	Recordkeeping Requirements

(6) The permittee shall maintain on-site, the document of certification received from the U.S. EPA or the Ohio EPA's Central Office documenting that the continuous SO2 monitoring system has been certified to meet the requirements of 40 CFR, Part 60, Appendix B, Performance Specification 2. The letter/document of certification shall be made available to the Director (Ohio EPA, Northwest District Office) upon request.

Each continuous monitoring system consists of all the equipment used to acquire and record data in units of all applicable standard(s), and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

e) Reporting Requirements

(1) Pursuant to OAC rule 3745-15-04 and ORC sections 3704.03(I) and 3704.031 and 40 CFR, Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the Ohio EPA, Northwest District Office documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any), of all 12 hour periods of SO2 values in excess of the applicable lbs/hr and NSPS limitations for SO2.

These reports also shall identify all instances of daily SO2 emission values in excess of the limitation specified in OAC rule 3745-18-08 (including those instances due to the bypassing of the Claus unit(s)) and shall specify the total SO2 emissions for the calendar quarter (in tons).

The permittee shall submit reports within 30 days following the end of each calendar quarter to the Ohio EPA, Northwest District Office documenting any continuous SO2 monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken.

The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit and control equipment malfunctions.

The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall also be included in the quarterly report.

If there are no excess emissions during the calendar quarter, the permittee shall submit a statement to that effect along with the emissions unit operating time during the reporting period and the date, time, reason, and corrective action(s) taken for each time period of emissions unit, control equipment, and/or monitoring system malfunctions.

The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line also shall be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

Pursuant to OAC rule 3745-15-04 and ORC sections 3704.03(I) and 3704.031, the permittee shall submit a summary of the excess emission report pursuant to 40 CFR, Part 60.7. The summary shall be submitted to the Ohio EPA, Northwest District Office within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

(2) Pursuant to 40 CFR, Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the Ohio EPA, Northwest District Office documenting any continuous O2system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken.

The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit and control equipment malfunctions.

The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall also be included in the quarterly report.

(3) All quarterly reports and deviation reports shall be submitted in accordance with the Standard Terms and Conditions of this permit.

(4) The permittee shall comply with the reporting requirements under 40 CFR, Part 63, Subpart CC, including the following sections:

63.655(f)(1)(ii)	Notification of Compliance Status – Identification of Miscellaneous Process Vents
63.655(g)	Semi-annual Deviation Report for Group 1 Miscellaneous Process Vents
63.655(g)(6)	Semi-annual Deviation Report for Group 1 Miscellaneous Process Vents – Excess Emissions Reporting

(5) The permittee shall comply with the applicable reporting requirements under 40 CFR, Part 63, Subpart UUU, including the following sections:

63.1563(e)	Notification Requirements
63.1568(b)(6) and 63.1658(b)(7)	Submit Notice of Compliance Status, including Operation, Maintenance and Monitoring Plan
63.1570(f)	Report Deviations
63.1574(a), 63.1574(a)(3), 63.1574(b), 63.1574(d), 63.1574(f)(1), Table 42.1, Table 42.2 and Table 42.3	Notice of Compliance Status – Identify Affected Sources, Emission Limits and Monitoring Options

63.1575(a), 63.1575(b)(1) through 63.1575(b)(5), 63.1575(c), 63.1575(e)(1) through 63.1575(e)(13), 63.1575(f)(1), 63.1575(f)(2), 63.1575(g) and Table 43	Compliance Report Requirements
63.1575(h)(1) and 63.1575(h)(2)	Startup, Shutdown and Malfunction Reporting Requirements

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitations:

0.14 lb of $PE/PM_{10}/PM_{2.5}$/hr and 0.61 ton of $PE/PM_{10}/PM_{2.5}$/yr, combustion emissions from the tail gas incinerator

Applicable Compliance Method:

The permittee may demonstrate compliance with the hourly limitation by multiplying the appropriate particulate emission factor of 7.6 pounds per million standard cubic feet, from AP-42 Chapter 1.4 (7/98), by the maximum fuel flow rate of 18,431 standard cubic feet/hr. If required, the permittee shall demonstrate compliance with this emission limitation by conducting emission testing in accordance with the requirements specified in Methods 1 through 4, and 5 of 40 CFR, Part 60, Appendix A.

The annual emission limitation was derived by multiplying the hourly emission limitation times 8,760 hrs/yr, and then dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the hourly emission limitation, compliance with the annual emission limitation shall also be demonstrated.

b. Emission Limitations:

0.10 lb of VOC/hr, 0.44 ton of VOC/yr, combustion emissions from the tail gas incinerator

Applicable Compliance Method:

The permittee may demonstrate compliance with the hourly limitation by multiplying the appropriate VOC emission factor of 5.5 pounds per million standard cubic feet, from AP-42 Chapter 1.4 (7/98), by the maximum fuel flow rate of 18,431 standard cubic feet/hr. If required, the permittee shall demonstrate compliance with the hourly emission limitation by conducting emission testing in accordance with Methods 1 through 4, and 18, 25, or 25A, as appropriate, of 40 CFR, Part 60, Appendix A.

The annual emission limitation was derived by multiplying the hourly emission limitation times 8,760 hrs/yr, and then dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the hourly emission limitation, compliance with the annual emission limitation shall also be demonstrated.

c. Emission Limitation:

Visible PE shall not exceed 20% opacity, as a six-minute average [combustion emissions from the tail gas incinerator]

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance with the visible PE limitation above in accordance with the methods and procedures specified in Method 9 of 40 CFR, Part 60, Appendix A.

d. Emission Limitations:

1.84 lbs of NOx/hr and 8.06 tons of NOx/rolling, 12-month period [combustion emissions from the tail gas incinerator]

Applicable Compliance Method:

The permittee may demonstrate compliance with the hourly limitation by multiplying the appropriate NOx emission factor of 100 pounds per million standard cubic feet, from AP-42 Chapter 1.4 (7/98), by the maximum fuel flow rate of 18,431 standard cubic feet/hr.

If required, the permittee shall demonstrate compliance with this emission limitation by conducting emission testing in accordance with the requirements specified in Methods 1 through 4, and 7 of 40 CFR, Part 60, Appendix A.

The rolling, 12-month emission limitation was established by multiplying the hourly emission limitation times the maximum operating schedule of 8,760 hrs/yr, and then dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the hourly emission limitation, compliance with the rolling, 12-month period emission limitation shall also be demonstrated.

e. Emission Limitation:

1.88 lbs of CO/hr and 8.23 tons of CO/rolling, 12-month period, combustion emissions from the tail gas incinerator

Applicable Compliance Method:

The hourly CO emission limitation was derived from a vendor guarantee of a maximum CO emissions rate of 100 parts per million.

If required, the permittee shall demonstrate compliance with this emission limitation by conducting emission testing in accordance with the requirements specified in Methods 1 through 4, and 10 of 40 CFR, Part 60, Appendix A.

The rolling, 12-month emission limitation was established by multiplying the hourly emission limitation by the maximum operating schedule of 8,760 hrs/yr, and then dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the hourly emission limitation, compliance with the rolling, 12-month period emission limitation shall also be demonstrated.

f. Emission Limitation:

CO_2e emissions shall not exceed 33,241 tons per rolling, 12-month period

Applicable Compliance Method:

The rolling, 12-month limitation represents the potential to emit based on an average flow rate during four stack tests between 2006 and 2008 of 17,311 standard cubic feet per minute (scfm) multiplied by 60 min/hr by 6.3 percent (the average fraction of GHG to total emissions during four stack tests) by 44 lb/lb mole conversion divided by 379 scf/lb mole conversion, multiplied by the maximum operating schedule of 8,760 hrs/yr, and then dividing by 2,000 lbs/ton.

g. Emission Limitations:

19.18 lbs of SO2/hr, as a 12-hr rolling average and 84.02 tons of SO2/rolling, 12-month period [process emissions from the tail gas incinerator]

Applicable Compliance Method:

Ongoing compliance with the SO2 emission limitations contained in this permit; 40 CFR, Part 60 and any other applicable standard(s) shall be demonstrated through the data collected as required in the monitoring and record keeping in d)(1) and d)(2), and through demonstration of compliance with the quality assurance/quality control plan which shall meet the testing and recertification requirements of 40 CFR, Part 60.

If required, the permittee shall demonstrate compliance with this emission limitation by conducting emission testing in accordance with the requirements specified in Methods 1 through 4, and 6 of 40 CFR, Part 60, Appendix A.

The rolling, 12-month emission limitation was established by multiplying the hourly emission limitation times the maximum operating schedule of 8,760 hrs/yr, and then dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the hourly emission limitation, compliance with the rolling, 12-month period emission limitation shall also be demonstrated.

h. Emission Limitation:

250 parts per million by volume (dry basis), 12-hour rolling average of SO2 at 0% excess air, process emissions from the tail gas incinerator

Applicable Compliance Method:

Ongoing compliance with the SO2 emission limitations contained in this permit; 40 CFR, Part 60 and any other applicable standard(s) shall be demonstrated through the data collected as required in the monitoring and record keeping in d)(1) and d)(2), and through demonstration of compliance with the quality assurance/quality control plan which shall meet the testing and recertification requirements of 40 CFR, Part 60.

If required, the permittee shall demonstrate compliance with the SO2 emission limitation above based on the results of emission testing conducted in accordance with the requirements specified in Methods 1 through 4, and 6 of 40 CFR, Part 60, Appendix A.

(2) The permittee shall comply with the applicable testing requirements under 40 CFR, Part 63, Subpart UUU, including the following sections:

63.1568(b)(5) and Table 33	Initial Compliance – New Source Performance Standard Test

g) Miscellaneous Requirements

(1) None.

7. P049, Sulfur Recovery Unit 3

Operations, Property and/or Equipment Description:

Sulfur Recovery Unit - Claus 3 with tail gas treatment unit, oxygen enrichment, and natural gas fired tail gas incinerator, capacity of 195 long tons per day

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(D)	Combustion emissions from the tail gas incinerator shall not exceed the following: 0.16 lb of particulate emissions/ particulate matter less than or equal to 10 microns in diameter/particulate matter less than or equal to 2.5 microns in diameter ($PE/PM_{10}/PM_{2.5}$)/hr and 0.72 ton of $PE/PM_{10}/PM_{2.5}$/yr 0.12 lb of volatile organic compounds (VOC)/hr and 0.52 ton of VOC/yr Visible PE shall not exceed 20% opacity, as a six-minute average The requirements of this rule also include compliance with 40 CFR, Part 63, Subpart CC (for the rich amine flash drum) and 40 CFR 60.104(a) See b)(2)a. and b)(2)b.
b.	OAC rule 3745-31-05(A), as effective 11/30/01	See b)(2)c. and b)(2)d.
c.	OAC rule 3745-31-05(A)(3), as effective 12/1/06	See b)(2)e.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
d.	ORC 3704.03(T)	See b)(2)f.
e.	OAC rule 3745-31-10 through 3745-31-20	Combustion emissions from the tail gas incinerator shall not exceed the following: 2.17 lbs of nitrogen oxides (NOx)/hr and 9.52 tons of NOx/rolling, 12-month period 1.83 lbs of carbon monoxide (CO)/hr and 8.00 tons of CO/rolling, 12-month period Carbon dioxide equivalents (CO_2e) emissions shall not exceed 40,512 tons per rolling, 12-month period Process emissions from the tail gas incinerator shall not exceed the following: 22.67 lbs of sulfur dioxide (SO2)/hr, as a 12-hour rolling average; 99.30 tons of SO2/rolling, 12-month period; and 250 parts per million by volume (dry basis) of SO2 at 0% excess air as a 12-hour rolling average See b)(2)g.
f.	40 CFR, Part 63, Subpart CC [40 CFR 63.640 – 63.656] Miscellaneous Group 1 process vent provisions for the new rich amine flash drum	See b)(2)n.
g.	40 CFR, Part 63, Subpart UUU [40 CFR 63.1560 – 63.1579] accordance with 40 CFR 63.1562, this emissions unit is an affected source consisting of a process vent or group of process vents on the Claus 3 sulfur recovery plant unit and the tail gas treatment unit serving the Claus 3 sulfur recovery plant, that are associated with sulfur recovery, including any bypass line(s), subject to the emission limitations/control measures specified in this section.]	See b)(2)m., d)(6) , e)(4) , and f)(2)

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
h.	40 CFR, Part 60, Subpart Ja 40 CFR 60.102a(f)(1)(i)	250 parts per million by volume (dry basis) of SO2 at 0% excess air as a 12-hour average See b)(2)f.
i.	OAC rule 3745-21-09(T)	leaks from petroleum refinery equipment [See b)(2)n.]
j.	OAC rule 3745-21-09(DD)	leaks from petroleum refinery equipment [See b)(2)n.]
k.	40 CFR, Part 60, Subpart VVa	leaks from petroleum refinery equipment [See b)(2)n.]
l.	40 CFR, Part 60, Subpart GGGa [40 CFR 60.640a through 60.679a]	leaks from petroleum refinery equipment [See b)(2)n.]
m.	40 CFR, Part 60, Subpart A	See 40 CFR 60.1 through 60.19
n.	40 CFR, Part 61, Subpart V	leaks from petroleum refinery equipment [See b)(2)n.]
o.	OAC rule 3745-17-11(B)(1)	None [See b)(2)k.]
p.	OAC rule 3745-17-07(A)	None [See b)(2)l.]
q.	40 CFR, Part 61, Subpart FF [40 CFR 61.340 – 61.358] [In accordance with 40 CFR 61.340, the sour water components of this emissions unit are an affected source since processing of wastewater containing benzene occurs.]	See b)(2)o.
r.	40 CFR, Part 61, Subpart A	See 40 CFR 61.01 through 61.19
s.	40 CFR 63.1 through 63.15	Table 6 to 40 CFR, Part 63, Subpart CC – Applicability of General Provisions to Subpart CC shows which parts of the General Provisions in 40 CFR 63.1 - 63.15 apply. Table 44 to 40 CFR, Part 63, Subpart UUU – Applicability of General Provisions to Subpart UUU shows which parts of the General Provisions in 40 CFR 63.1 - 63.15 apply.

(2) Additional Terms and Conditions

a. It is assumed that all PE are equivalent to both PM_{10} and $PM_{2.5.}$

b. This permit establishes the following federally enforceable emission limitations for the purpose of representing the potential to emit of the emissions unit:

i. 0.16 lb of PE/PM_{10}/$PM_{2.5}$/hr and 0.72 ton of PE/PM_{10}/$PM_{2.5}$/yr; and

ii. 0.12 lb of VOC/hr and 0.52 ton of VOC/yr.

c. Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3), as effective 11/30/01 for PM_{10}, VOC, NOx and CO have been determined to be compliance with OAC rule 3745-31-05(D) and OAC rule 3745-31-10 through 3745-31-20 and compliance with the terms and conditions of this permit.

d. The permittee has satisfied the BAT requirements pursuant to OAC rule 3745-31-05(A)(3), as effective November 30, 2001, in this permit. On December 1, 2006, paragraph (A)(3) of OAC rule 3745-31-05 was revised to conform to ORC changes effective August 3, 2006 (S.B. 265 changes), such that BAT is no longer required by State regulation for NAAQS pollutant emissions less than 10 tons per year. However, that rule revision has not yet been approved by U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revision to OAC rule 3745-31-05, the requirement to satisfy BAT still exists as part of the federally-approved SIP for Ohio.

Once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05, then these emission limits and control measures no longer apply.

e. This rule paragraph applies once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 as part of the State Implementation Plan.

The BAT requirements under OAC rule 3745-31-05(A)(3)(a) do not apply to the emissions of PM_{10}, VOC, NOx and CO since the potential to emit is less than 10 tons per year, taking into account the federally enforceable restrictions established under OAC rule 3745-31-05(D) and OAC rule 3745-31-10 through 3745-20 in this permit.

f. The BAT requirements under ORC 3704.03(T) for SO2 have been determined to be compliance with OAC rule 3745-31-10 through 3745-31-20.

g. The permittee shall employ Best Available Control Technology (BACT) for this emissions unit. BACT has been determined to be the following:

Pollutant	BACT Requirements
NOx	2.17 lbs of NOx/hr; and Use of good combustion practices.
SO2	Use of tail gas treatment unit and tail gas incinerator; Compliance with 40 CFR, Part 60, Subpart Ja; 22.67 lbs of SO2/hr, as a 12-hr rolling average; and

	250 parts per million by volume (dry basis) of SO2 at 0% excess air as a 12-hour rolling average.
CO	1.83 lbs of CO/hr; and Use of good combustion practices.
CO_2e	Use of low-carbon gaseous fuel (natural gas) as supplemental fuel in the tail gas incinerator

h. Each continuous SO2 monitoring system shall be certified to meet the requirements of 40 CFR, Part 60, Appendix B, Performance Specifications 2 and 6. At least 45 days before commencing certification testing of the continuous SO2 monitoring system(s), the permittee shall develop and maintain a written quality assurance/quality control plan designed to ensure continuous valid and representative readings of SO2 emissions from the continuous monitor(s), in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the continuous SO2 monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR Part 60.

i. Each continuous O2 monitoring system shall be certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 3. At least 45 days before commencing certification testing of the continuous O2 monitoring system(s), the permittee shall develop and maintain a written quality assurance/quality control plan designed to ensure continuous valid and representative readings of O2 emissions from the continuous monitor(s), in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR, Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the continuous O2 monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR, Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR, Part 60.

j. The continuous SO2 and O2 emission monitoring systems consists of all the equipment used to acquire data to provide a record of emissions and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data recording/processing hardware and software.

k. The uncontrolled mass rate of PE* from this emissions unit is less than 10 pounds/hour. Therefore, pursuant to OAC rule 3745-17-11(A)(2)(a)(ii), Figure II of OAC rule 3745-17-11 does not apply. In addition, Table I of OAC rule 3745-17-

11 does not apply because the process weight rate is equal to zero. "Process weight" is defined in OAC rule 3745-17-01(B)(14).

* The burning of gaseous fuels in the tail gas incinerator is the only source of PE from this emissions unit

l. This emissions unit is exempt from the visible PE limitations specified in OAC rule 3745-17-07(A) pursuant to OAC rule 3745-17-07(A)(3)(h) because the emissions unit is not subject to the requirements of OAC rule 3745-17-11.

m. The permittee shall comply with the applicable control requirements, operating limits, emission limits and work practice standards under 40 CFR, Part 63, Subpart UUU, including the following sections:

63.1568(a)(1) and Table 29	Sulfur Dioxide (SO2) Emission Limit for New Source Performance Standard Units: Meet Option A – 250 parts per million by volume (dry basis) of SO2 at 0% excess air (use of oxidation or reduction control system followed by incineration)
63.1568(a)(3)	Prepare Operation, Maintenance and Monitoring Plan
63.1570(a)	Compliance with Non-opacity Standards during time specified in 40 CFR 63.6(f)(1)
63.1570(g)	Deviations during Startup, Shutdown or Malfunction

n. This emissions unit is subject to the appropriate provisions (including operational restrictions, monitoring and record keeping, reporting, and testing) of OAC rule 3745-21-09(T) – Leaks from petroleum refinery equipment, OAC rule 3745-21-09(DD) – Leaks from process units that produce organic chemicals, 40 CFR, Part 60, Subpart VVa (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction or Modification Commenced after November 7, 2006), 40 CFR, Part 60, Subpart GGGa (Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced after November 7, 2006), 40 CFR, Part 63, Subpart CC (Petroleum Refinery MACT Standards), and 40 CFR, Part 61, Subpart V (National Emission Standard for Equipment Leaks – Fugitive Emission Sources).

The requirements of these rules are equivalent to or less stringent than the alternative leak detection and repair (LDAR) monitoring plan submitted by the permittee, pursuant to OAC rule 3745-21-09(T)(4) and 40 CFR, Part 63, Subpart

CC. Terms and conditions for the alternative LDAR plan are listed in section B.2 of the Facility-Wide Terms and Conditions of the facility's renewal Title V with effective date of 3/26/13.

o. The permittee shall include the sour water components of the new Claus 3 sulfur recovery unit in the current site benzene waste operations program.

c) Operational Restrictions

(1) None.

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall install, operate, and maintain equipment to continuously monitor and record SO2 emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR, Part 60.

The permittee shall maintain records of all data obtained by the continuous SO2 monitoring system including, but not limited to:

a. emissions of SO2 in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of SO2 in pounds per hour and in units of the applicable standard(s) in the appropriate averaging period;

c. results of quarterly cylinder gas audits;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

f. hours of operation of the emissions unit, continuous SO2 monitoring system, and control equipment;

g. the date, time, and hours of operation of the emissions unit without the control equipment and/or the continuous SO2 monitoring system;

h. the date, time, and hours of operation of the emissions unit during any malfunction of the control equipment and/or the continuous SO2 monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(2) Prior to the installation of the continuous SO2 monitoring system, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR, Part 60, Appendix B, Performance Specification 2. The Ohio EPA, Central Office shall approve the proposed sampling site and certify that the continuous SO2 monitoring system meets the requirements of Performance Specifications 2 and 6. Once received, the letter(s)/document(s) of certification shall be maintained on-site and shall be made available to the Director (the Ohio EPA, Northwest District Office) upon request.

(3) The permittee shall install, operate and maintain equipment to continuously monitor and record O2 emitted from this emissions unit in percent O2. The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR, Part 60.

The permittee shall maintain records of all data obtained by the continuous O2 monitoring system including, but not limited to:

a. the percent O2 with each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. results of quarterly cylinder gas audits;

c. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

d. results of required relative accuracy test audit(s);

e. hours of operation of the emissions unit, continuous O2 monitoring system;

f. the date, time, and hours of operation of the emissions unit without the continuous O2 monitoring system;

g. the date, time, and hours of operation of the emissions unit during any malfunction of the continuous O2 monitoring system; as well as,

h. the reason (if known) and the corrective actions taken (if any) for each such event in (f) and (g).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(4) Prior to the installation of the continuous O2 monitoring system, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR, Part 60, Appendix B, Performance Specification 3. The Ohio EPA, Central Office shall approve the proposed sampling site and certify that the continuous O2 monitoring system meets the requirements of Performance Specification 3. Once received, the letter/document of certification shall be maintained on-site and shall be made available to the Director (the Ohio EPA, Northwest District Office) upon request.

(5) The permittee shall include the SRU fugitive emissions and associated components in the current site fugitive leak detection and repair (LDAR) program. The LDAR program shall be conducted in accordance with the alternative monitoring plan submitted by the permittee. Applicable requirements are listed in section B.2 of the Facility-Wide Terms and Conditions of the facility's renewal Title V with effective date of 3/26/13.

(6) The permittee shall comply with the applicable monitoring and recordkeeping requirements under 40 CFR, Part 63, Subpart UUU, including the following sections:

63.1568(b)(1) and Table 31	Install, Operate and Maintain Sulfur Dioxide Continuous Emission Monitor
63.1568(c)(1), Table 34 and Table 35	Continuous Compliance - Sulfur Dioxide Continuous Emission Monitor
63.1568(c)(2)	Continuous Compliance with Operation, Maintenance and Monitoring Plan
63.1570(c)	General Duty – Log Prior to Continuous Monitoring System Validation
63.1572(a)(1), 63.1572(a)(3), 63.1572(a)(4), 63.1572(d)(1), 63.1572(d)(2) and Table 40	Sulfur Dioxide Continuous Emission Monitor Requirements
63.1574(f)(2)(i), 63.1574(f)(2)(ii), and 63.1574(f)(2)(viii) through 63.1574(f)(2)(x)	Operation, Maintenance and Monitoring Plan Requirements
63.1576(a)(1), 63.1576(a)(2), 63.1576(b)(1) through 63.1576(b)(5), 63.1576(d) through 63.1576(i), Table 34 and Table 35	Recordkeeping Requirements

(7) The permittee shall maintain on-site, the document of certification received from the U.S. EPA or the Ohio EPA's Central Office documenting that the continuous SO2 monitoring system has been certified to meet the requirements of 40 CFR, Part 60, Appendix B, Performance Specification 2. The letter/document of certification shall be made available to the Director (Ohio EPA, Northwest District Office) upon request.

Each continuous monitoring system consists of all the equipment used to acquire and record data in units of all applicable standard(s), and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

e) Reporting Requirements

(1) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous SO2 monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR Parts 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the Ohio EPA, Northwest District Office, documenting all instances of SO2 emissions in excess of any applicable limit specified in this permit, 40 CFR, Part 60, OAC Chapter 3745-18, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous SO2 and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total SO2 emissions for the calendar quarter (tons);

vi. the total operating time (hours) of the emissions unit;

vii. the total operating time of the continuous SO2 monitoring system while the emissions unit was in operation;

viii. results and date of quarterly cylinder gas audits;

ix. unless previously submitted, results and date of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

x. unless previously submitted, the results of any relative accuracy test audit showing the continuous SO2 monitor out-of-control and the compliant results following any corrective actions;

xi. the date, time, and duration of any/each malfunction** of the continuous SO2 monitoring system, emissions unit, and/or control equipment;

xii. the date, time, and duration of any downtime** of the continuous SO2 monitoring system and/or control equipment while the emissions unit was in operation; and

xiii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(xi) and (xii).

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

(2) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous O2 monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR Parts 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the Ohio EPA, Northwest District Office, documenting all instances of continuous O2 monitoring system downtime and malfunction while the emissions unit was on line.

b. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous O2 and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the total operating time (hours) of the emissions unit;

v. the total operating time of the continuous O2 monitoring system while the emissions unit was in operation;

vi. results and dates of quarterly cylinder gas audits;

vii. unless previously submitted, results and dates of the relative accuracy test audit(s) (during appropriate quarter(s));

viii. unless previously submitted, the results of any relative accuracy test audit showing the continuous O2 monitor out-of-control and the compliant results following any corrective actions;

ix. the date, time, and duration of any/each malfunction* of the continuous O2 monitoring system while the emissions unit was in operation;

x. the date, time, and duration of any downtime* of the continuous O2 monitoring system while the emissions unit was in operation; and

xi. the reason (if known) and the corrective actions taken (if any) for each event in (b)(ix) and (x).

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

(3) All quarterly reports and deviation reports shall be submitted in accordance with the Standard Terms and Conditions of this permit.

(4) The permittee shall comply with the applicable reporting requirements under 40 CFR, Part 63, Subpart UUU, including the following sections:

63.1563(e)	Notification Requirements
63.1568(b)(6) and 63.1658(b)(7)	Submit Notice of Compliance Status, including Operation, Maintenance and Monitoring Plan
63.1570(f)	Report Deviations
63.1574(a), 63.1574(a)(3), 63.1574(b), 63.1574(d), 63.1574(f)(1), Table 42.1, Table 42.2 and Table 42.3	Notice of Compliance Status – Identify Affected Sources, Emission Limits and Monitoring Options
63.1575(a), 63.1575(b)(1) through 63.1575(b)(5), 63.1575(c), 63.1575(e)(1) through 63.1575(e)(13), 63.1575(f)(1), 63.1575(f)(2), 63.1575(g) and Table 43	Compliance Report Requirements
63.1575(h)(1) and 63.1575(h)(2)	Startup, Shutdown and Malfunction Reporting Requirements

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitations:

0.16 lb of PE/PM_{10}/$PM_{2.5}$/hr and 0.72 ton of PE/PM_{10}/$PM_{2.5}$/yr, combustion emissions from the tail gas incinerator

Applicable Compliance Method:

The permittee may demonstrate compliance with the hourly limitation by multiplying the appropriate particulate emission factor of 7.6 pounds per million standard cubic feet, from AP-42 Chapter 1.4 (7/98), by the maximum fuel flow rate of 22,000 standard cubic feet/hr. If required, the permittee shall demonstrate compliance with this emission limitation by conducting emission testing in accordance with the requirements specified in Methods 1 through 4, and 5 of 40 CFR, Part 60, Appendix A.

The annual emission limitation was derived by multiplying the hourly emission limitation times 8,760 hrs/yr and then dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the hourly emission limitation, compliance with the annual emission limitation shall also be demonstrated.

b. Emission Limitations:

0.12 lb of VOC/hr, 0.52 ton of VOC/yr, combustion emissions from the tail gas incinerator

Applicable Compliance Method:

The permittee may demonstrate compliance with the hourly limitation by multiplying the appropriate VOC emission factor of 5.5 pounds per million standard cubic feet, from AP-42 Chapter 1.4 (7/98), by the maximum fuel flow rate of 22,000 standard cubic feet/hr. If required, the permittee shall demonstrate compliance with the hourly emission limitation by conducting emission testing in accordance with Methods 1 through 4, and 18, 25, or 25A, as appropriate, of 40 CFR, Part 60, Appendix A.

The annual emission limitation was derived by multiplying the hourly emission limitation times 8,760 hrs/yr, and then dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the hourly emission limitation, compliance with the annual emission limitation shall also be demonstrated.

c. Emission Limitation:

Visible PE shall not exceed 20% opacity, as a six-minute average [combustion emissions from the tail gas incinerator]

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance with the visible PE limitation above in accordance with the methods and procedures specified in Method 9 of 40 CFR, Part 60, Appendix A.

d. Emission Limitations:

2.17 lbs of NOx/hr and 9.52 tons of NOx/rolling, 12-month period, combustion emissions from the tail gas incinerator

Applicable Compliance Method:

The permittee may demonstrate compliance with the hourly limitation by multiplying the appropriate NOx emission factor of 100 pounds per million standard cubic feet, from AP-42 Chapter 1.4 (7/98), by the maximum fuel flow rate of 22,000 standard cubic feet/hr.

If required, the permittee shall demonstrate compliance with this emission limitation by conducting emission testing in accordance with the requirements specified in Methods 1 through 4, and 7 of 40 CFR, Part 60, Appendix A.

The rolling, 12-month emission limitation was established by multiplying the hourly emission limitation by the maximum operating schedule of 8,760 hrs/yr, and then dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the hourly emission limitation, compliance with the rolling, 12-month period emission limitation shall also be demonstrated.

e. Emission Limitations:

1.83 lbs of CO/hr and 8.00 tons of CO/rolling, 12-month period, combustion emissions from the tail gas incinerator

Applicable Compliance Method:

The permittee may demonstrate compliance with the hourly limitation by multiplying the appropriate CO emission factor of 84 pounds per million standard cubic feet, from AP-42 Chapter 1.4 (7/98), by the maximum fuel flow rate of 22,000 standard cubic feet/hr.

If required, the permittee shall demonstrate compliance with this emission limitation by conducting emission testing in accordance with the requirements specified in Methods 1 through 4, and 10 of 40 CFR, Part 60, Appendix A.

The rolling, 12-month emission limitation was established by multiplying the hourly emission limitation by the maximum operating schedule of 8,760 hrs/yr, and then dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the hourly emission limitation, compliance with the rolling, 12-month period emission limitation shall also be demonstrated.

f. Emission Limitation:

CO_2e emissions shall not exceed 40,512 tons per rolling, 12-month period

Applicable Compliance Method:

The rolling, 12-month limitation represents the estimated emissions at the maximum design sulfur load of 195 long tons per day which is estimated to result in 21,098 scfm of stack gas flow and an assumed 6.3% CO2 concentration in the stack based on past stack testing of the existing SRU unit. The resulting calculated GHG emissions are 40,512 tons per rolling, 12-month period.

Compliance shall be demonstrated by use of actual stack gas flow rates and an assumed 6.3% CO2 concentration in the stack (or other more recent test data, if available).

g. Emission Limitation:

22.67 lbs of SO2/hr, as a 12-hour rolling average and 99.30 tons of SO2/rolling, 12-month period [process emissions from the tail gas incinerator]

Applicable Compliance Method:

Ongoing compliance with the SO2 emission limitations contained in this permit; 40 CFR, Part 60 and any other applicable standard(s) shall be demonstrated through the data collected as required in the monitoring and record keeping in d)(1), and through demonstration of compliance with the quality assurance/quality control plan which shall meet the testing and recertification requirements of 40 CFR, Part 60.

If required, the permittee shall demonstrate compliance with the SO2 emission limitation above based on the results of emission testing conducted in accordance with the requirements specified in Methods 1 through 4, and 6 of 40 CFR, Part 60, Appendix A.

The rolling, 12-month emission limitation was established by multiplying the hourly emission limitation by the maximum operating schedule of 8,760 hrs/yr, and then dividing by 2,000 lbs/ton. Therefore, provided compliance is shown with the hourly emission limitation, compliance with the rolling, 12-month period emission limitation shall also be demonstrated.

h. Emission Limitation:

250 parts per million by volume (dry basis), as a 12-hour rolling average of SO2 at 0% excess air, process emissions from the tail gas incinerator

Applicable Compliance Method:

Ongoing compliance with the SO2 emission limitations contained in this permit; 40 CFR, Part 60 and any other applicable standard(s) shall be demonstrated through the data collected as required in the monitoring and record keeping in d)(1), and through demonstration of compliance with the quality assurance/quality control plan which shall meet the testing and recertification requirements of 40 CFR, Part 60. If required, the permittee shall demonstrate compliance with the SO2 emission limitation above based on the results of emission testing conducted in accordance with the requirements specified in Methods 1 through 4, and 6 of 40 CFR, Part 60, Appendix A.

(2) The permittee shall comply with the applicable testing requirements under 40 CFR, Part 63, Subpart UUU, including the following sections:

63.1568(b)(5) and Table 33	Initial Compliance – New Source Performance Standard Test

(3) Within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup, the permittee shall conduct certification tests of the continuous SO2 monitoring system in units of the applicable standard(s) to demonstrate compliance with 40 CFR, Part 60, Appendix B, Performance Specifications 2 and 6; and ORC section 3704.03(I).

Personnel from the Ohio EPA Central Office and the Ohio EPA, Northwest District Office shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. Two copies of the test results shall be submitted to Ohio EPA, one copy to the Ohio EPA, Northwest District Office and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification of the continuous SO2 monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets the requirements of 40 CFR Part 60, Appendix B, Performance Specifications 2 and 6; and ORC section 3704.03(I).

Ongoing compliance with the SO2 emission limitations contained in this permit, 40 CFR, Part 60, and any other applicable standard(s) shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the testing and recertification requirements of 40 CFR, Part 60.

(4) Within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup, the permittee shall conduct certification tests of the continuous O2 monitoring system to demonstrate compliance with 40 CFR, Part 60, Appendix B, Performance Specification 3 and ORC section 3704.03(I).

Personnel from the Ohio EPA Central Office and the Ohio EPA, Northwest District Office shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. Two copies of the test results shall be submitted to Ohio EPA, one copy to the Ohio EPA, Northwest District Office and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification of the continuous O2 monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets the requirements of 40 CFR, Part 60, Appendix B, Performance Specifications 3 and ORC section 3704.03(I).

Ongoing compliance with the O2 monitoring requirements contained in this permit, 40 CFR, Part 60, and any other applicable standard(s) shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit; and demonstration of compliance with the quality assurance/quality control plan, which shall meet all of the testing and recertification requirements of 40 CFR, Part 60.

g) Miscellaneous Requirements

(1) None.

8. P050, Acid Gas Flare

Operations, Property and/or Equipment Description:

Sulfur Recovery Units Acid Gas Flare, non-assisted

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(D)	0.02 ton particulate emissions/ particulate matter less than or equal to 10 microns in diameter/particulate matter less than or equal to 2.5 microns in diameter ($PE/PM_{10}/PM_{2.5}$)/yr from pilot and sweep gas firing only 0.32 ton volatile organic compounds (VOC)/yr from pilot and sweep gas firing only 1.00 ton of NOx/yr during periods of process unit start-up and shutdown 100.00 tons of SO2/yr during periods of process unit start-up and shutdown See b)(2)a. and b)(2)b.
b.	OAC rule 3745-31-05(A)(3), as effective 11/30/01	See b)(2)c. and b)(2)d.
c.	OAC rule 3745-31-05(A)(3), as effective 12/1/06	See b)(2)e.
d.	ORC 3704.03(T)	See b)(2)f.

e.	40 CFR, Part 60.18	See b)(2)g.
f.	40 CFR, Part 60, Subpart Ja	See b)(2)h.
g.	40 CFR, Part 60, Subpart A	See 40 CFR 60.1 through 60.19
h.	OAC rules 3745-31-10 through 3745-31-20	0.15 ton nitrogen oxides (NOx)/rolling, 12-month period from pilot and sweep gas firing only 0.001 ton sulfur dioxide (SO2)/rolling, 12-month period from pilot and sweep gas firing only 0.84 ton carbon monoxide (CO)/rolling, 12-month period from pilot and sweep gas firing only Carbon dioxide equivalents (CO_2e) emissions shall not exceed 266 tons per rolling, 12-month period from pilot and sweep gas firing only See b)(2)i.

(2) Additional Terms and Conditions

a. It is assumed that all PE are equivalent to both PM_{10} and $PM_{2.5}$.

b. This permit establishes the following federally enforceable emission limitations for the purpose of representing the potential to emit of the emissions unit:

i. 0.02 ton PE/PM_{10}/$PM_{2.5}$/yr from pilot and sweep gas firing only;

ii. 0.32 ton VOC/yr from pilot and sweep gas firing only;

iii. 1.00 ton of NOx/yr during periods of process unit start-up and shutdown; and

iv. 100.00 tons of SO2/yr during periods of process unit start-up and shutdown.

The emission limitations for NOx and SO2 during start-up and shutdown were established to alleviate reporting requirements associated with reportable quantities (RQ) under the Superfund Amendments and Reauthorization Act (SARA). The allowable limitations above do not apply to emissions associated with malfunctions and/or process upsets of the process unit. Any SO2 emissions associated with the start-up and shutdown of the sulfur recovery units at the facility (emissions units P040 and P049) that are routed to this flare must still be applied to the emissions limitation of 100 lbs SO2/1,000 lbs of sulfur processed contained in OAC rule 3745-18-08(C)(3).

c. Best Available Technology (BAT) requirements for PM_{10}, VOC, NOx and CO under OAC rule 3745-31-05(A)(3), as effective 11/30/01 have been determined to be compliance with OAC rule 3745-31-05(D) and OAC rule 3745-31-10 through 3745-31-20, use of inherently clean gaseous fuel (refinery fuel gas or natural gas) for pilot and sweep gas, good combustion practices, and compliance with the terms and conditions of this permit.

d. The permittee has satisfied the BAT requirements pursuant to OAC rule 3745-31-05(A)(3), as effective November 30, 2001, in this permit. On December 1, 2006, paragraph (A)(3) of OAC rule 3745-31-05 was revised to conform to ORC changes effective August 3, 2006 (S.B. 265 changes), such that BAT is no longer required by State regulation for NAAQS pollutant emissions less than 10 tons per year. However, that rule revision has not yet been approved by U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revision to OAC rule 3745-31-05, the requirement to satisfy BAT still exists as part of the federally-approved SIP for Ohio. Once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05, then these emission limits and control measures no longer apply.

e. This rule paragraph applies once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 as part of the State Implementation Plan.

   The BAT requirements under OAC rule 3745-31-05(A)(3)(a) do not apply to the emissions of PM_{10}, VOC, NOx and CO since the potential to emit is less than 10 tons per year.

f. BAT requirements under ORC 3704.03(T) have been determined to be compliance with OAC rule 3745-31-05(D).

g. This flare will be used to control H2S emissions in the feed stream to the sulfur recovery units (Claus 1, Claus 2 and Claus 3 units) emissions units P040 and P049, during periods of start-up, shutdown and malfunction of those emissions units and associated equipment. The Claus sulfur recovery units are subject to MACT standards in 40 CFR, Part 63, Subpart UUU, but this flare as a control device for the amine units that feed the Claus units is not an affected source to the requirements of Subpart UUU.

h. This emissions unit shall be designed for and operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

i. The permittee shall comply with the following requirements in 40 CFR, Part 60, Subpart Ja for new flares:

   i. Develop and implement a written flare management plan in accordance with 40 CFR 60.103a(a)(1) through (7);

   ii. Conduct a root cause analysis and corrective action plan whenever the discharge to the flare exceeds 500,000 standard cubic feet above the baseline in any 24-hour period;

iii. Any fuel gas burned shall not exceed a maximum of 162 parts per million by volume hydrogen sulfide content, as determined hourly on a 3-hour rolling average basis. This limit does not apply to process upset gases, fuel gas that is released to the flare as a result of relief valve leakage, or other emergency malfunctions; and

iv. Install, operate, calibrate and maintain a monitor to continuously measure and record the flow rate of gas discharged to the flare.

j. The permittee shall employ Best Available Control Technology (BACT) for this emissions unit. BACT has been determined to be the following:

Pollutant	BACT Requirements
NOx	Use of good combustion practices
SO2	Use of natural gas or refinery fuel gas for the flare pilot flame and sweep gases, and implementation of a load shedding plan to minimize periods of gas release from the sulfur recovery units (Claus 1, Claus 2 and Claus 3 units) to the acid gas flare
CO	Use of good combustion practices
CO_2e	Use of low-carbon gaseous fuels (refinery fuel gas or natural gas) in the flare's pilot and sweep gases

c) Operational Restrictions

(1) The flare shall be operated at all times when emissions are being vented to it.

(2) The flare shall be operated with a pilot flame present at all times.

(3) The flare shall be operated using good combustion practices as BACT which shall be demonstrated by complying with the following flare requirements of 40 CFR 60.18 (although 40 CFR 60.18 is not otherwise applicable).

(4) Only gases with a net heating value of 7.45 MJ/scm (200 Btu/scf) or greater shall be burned in this emissions unit. Net heating value shall be calculated as specified in 40 CFR Part 60.18(f)(3).

The flare shall be operated with an exit velocity less than 18.3 m/sec (60 ft/sec) except as specified in sections c)(4) and c)(5).

(5) If the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf), the permittee may operate the flare at an exit velocity equal to or greater than 18.3 m/sec (60 ft/sec), but less than 122 m/sec (400 ft/sec).

(6) Non-assisted flares may be operated with an exit velocity less than the maximum permitted velocity, but not greater than 122 m/sec (400 ft/sec). The maximum permitted velocity shall be determined in accordance with 40 CFR, Part 60.18(f)(5).

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall collect and record the following information during periods of start-up and shut-down:

a. the flare flow rate, in scf per hour;

b. the high heating value, in Btu/scf, as determined from the flare gas molecular weight and source of the gas;

c. the concentration of hydrogen sulfide in the flare gas, in weight fraction;

d. an indication of which process is undergoing start-up/shut-down mode;

e. the number of hours the process operated in start-up/shut-down mode;

f. the calculated NOx emissions using the following equation:

$E = (FR) \times (HV) \times (T) \times (EF)/1{,}000{,}000$

Where:

E = NOx emissions in tons for each individual start-up and shut-down event;

FR = flare flow rate in scf per hour;

HV = high heating value, in Btu/scf;

T = time duration for each start-up/shut down event, in hours; and

EF = NOx emission factor of 0.068 lb of NOx/mmBtu (AP-42 Section 13.5, Industrial Flares [9/91])

g. the annual NOx emission rate calculated as follows:

$ET = E1 + E2 + E3 + ... + En$

Where:

ET = Annual NOx emissions, in tons, as summed for the calendar year from January to December; and

En = NOx emissions, in tons, for each individual start-up/shut-down event during the calendar year

h. the calculated SO2 emissions using the following equation:

$E = \{(FR) \times (H2S)]/379.7\} \times (0.98) \times (64) \times (T)$

where:

E = SO_2 emissions in tons for each individual start-up and shut-down event;

FR = flare flow rate in scf per hour;

H_2S = volume fraction of hydrogen sulfide in flare gas;

379.7 = the volume, in ft^3, of one lb mole of gas at standard conditions (60 degrees F & 1 atm) from the ideal gas law;

0.98 = efficiency of the flare for converting a lb mole of H_2S into a lb mole of SO_2;

64 = molecular weight of SO_2 in lb/lb mole; and

T = time duration for each start-up/shut down event, in hours

i. the annual SO_2 emission rate calculated as follows:

$ET = E_1 + E_2 + E_3 + ... + E_n$

Where:

ET = Annual SO_2 emissions, in tons, as summed for the calendar year from January to December; and

E_n = SO_2 emissions, in tons, for each individual start-up/shut-down event during the calendar year

(2) The permittee shall operate and maintain a device to continuously monitor the pilot flame when the emissions unit is in operation. The monitoring device and any recorder shall be calibrated, operated, and maintained in accordance with the manufacturer's recommendations, instructions, and operating manuals. The monitoring device must complete a minimum of one cycle of operation for each successive 15-minute period.

The permittee shall record the following information each day:

a. all periods during which there was no pilot flame; and

b. the downtime for the flare and monitoring equipment.

(3) The permittee shall continuously monitor either visually and/or by camera whether or not there are visible emissions from the flare. Whenever the permittee observes visible emissions from the flare, the permittee shall record the start-time and end-time of visible emissions in an operations log.

e) Reporting Requirements

(1) The permittee shall submit deviation (excursion) reports that identify all periods during which the flare pilot flame was not functioning properly. The reports shall include the date, time, and duration of each such period. The quarterly deviation reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

(2) The permittee shall submit quarterly deviation reports that include the start-time and end-time of visible emissions observed from the flare that exceed a total time of five minutes during any consecutive two hour period. The quarterly deviation reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

(3) The permittee shall submit annual reports that summarize the total annual actual emissions of NOx and SO2 during periods of process unit start-up and shutdown. The report shall be submitted by January 31 of each year and shall cover the previous calendar year.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

0.02 ton PE/PM_{10}/$PM_{2.5}$/yr from the flare's pilot and sweep gases

Applicable Compliance Method:

The annual emission limitation above represents the potential to emit [see b)(2)b.] based on an emission factor of 0.0075 lb of PE/PM_{10}/$PM_{2.5}$/million Btu* multiplied by a maximum heat input to the flare's pilot and sweep gases of 0.519 million Btu/hr, multiplied by the maximum operating schedule of 8,760 hrs/yr, and then dividing by 2,000 lbs/ton.

*The emission factor was determined in accordance with AP-42, Table 1.4-2 (7/98).

b. Emission Limitation:

0.32 ton VOC/yr from the flare's pilot and sweep gases

Applicable Compliance Method:

The annual emission limitation above represents the potential to emit [see b)(2)b.] based on an emission factor of 0.14 lb of VOC/million Btu* multiplied by a maximum heat input to the flare's pilot and sweep gases of 0.519 million Btu/hr, multiplied by the maximum operating schedule of 8,760 hrs/yr, and then dividing by 2,000 lbs/ton.

*The emission factor was determined in accordance with AP-42, Table 13.5-1 (9/91).

c. Emission Limitation:

1.00 ton of NOx/yr during periods of process unit start-up and shutdown

Applicable Compliance Method:

Compliance with the annual NOx emission limitation shall be demonstrated through recordkeeping requirements in section d)(1).

d. Emission Limitation:

100.00 tons of SO2/yr during periods of process unit start-up and shutdown

Applicable Compliance Method:

Compliance with the annual SO2 emission limitation shall be demonstrated through record keeping requirements in section d)(1).

e. Emission Limitation:

No visible emissions except for periods not to exceed a total of five minutes during any two consecutive hours

Applicable Compliance Method:

If required, compliance with the no VE limitation above shall be demonstrated based upon the procedures specified in Method 22 of 40 CFR, Part 60, Appendix A.

f. Emission Limitation:

0.15 ton NOx/rolling, 12-month period from the flare's pilot and sweep gases

Applicable Compliance Method:

The rolling, 12-month limitation above represents the potential to emit [see b)(2)j.] based on an emission factor of 0.068 lb of NOx/million Btu* multiplied by a maximum heat input of 0.519 million Btu/hr from the flare's pilot and sweep gases, multiplied by the maximum operating schedule of 8,760 hrs/yr, and then dividing by 2,000 lbs/ton.

*The emission factor was determined in accordance with AP-42, Table 13.5-1 (9/91).

g. Emission Limitation:

0.001 ton SO2/rolling, 12-month period from the flare's pilot and sweep gases

Applicable Compliance Method:

The rolling, 12-month limitation above represents the potential to emit [see b)(2)j.] based on an emission factor of 0.0006 lb of SO2/million Btu* multiplied by a maximum heat input of 0.519 million Btu/hr from the flare's pilot and sweep gases, multiplied by the maximum operating schedule of 8,760 hrs/yr, and then dividing by 2,000 lbs/ton.

*The emission factor was determined in accordance with AP-42, Table 1.4-2 (7/98).

h. Emission Limitation:

0.84 ton CO/rolling, 12-month period from the flare's pilot and sweep gases

Applicable Compliance Method:

The rolling, 12-month limitation above represents the potential to emit [see b)(2)j.] based on an emission factor of 0.37 lb of CO/million Btu* multiplied by a maximum heat input of 0.519 million Btu/hr from the flare's pilot and sweep gases, multiplied by the maximum operating schedule of 8,760 hrs/yr, and then dividing by 2,000 lbs/ton.

*The emission factor was determined in accordance with AP-42, Table 13.5-1 (9/91).

i. Emission Limitation:

CO_2e emissions shall not exceed 266 tons per rolling, 12-month period from pilot and sweep gas firing only

Applicable Compliance Method:

The rolling, 12-month limitation above represents the potential to emit [see b)(2)j.] based on an emission factor of 53.02 kg of CO_2/million Btu* multiplied by a conversion factor of 2.204 lbs/kg, times the maximum heat input of 0.519 million Btu/hr from the flare's pilot and sweep gases, multiplied by the maximum operating schedule of 8,760 hrs/yr and dividing by 2,000 lbs/ton.

*The emission factor was determined in accordance with 40 CFR, Part 98, Table C-1, natural gas, global warming potential (GWP) from Table A-1.

g) Miscellaneous Requirements

(1) None.