Exhibit #1

Technical Review & Comments Concerning Utah Department of Environmental Quality - Division of Air Quality (UDEQ-DAQ) Intent to Approve #DAQE-IN101230041-13 [06/05/2013], UDEQ-DAQ Source Plan Review [Project #N101230041] & all Notice of Intent Application Materials Submitted for Heavy Crude Processing Project of Holly Refining & Marketing Company, LLC Petroleum Refinery at Woods Cross, Davis County, UT

Presented to

Utah Department of Environmental Quality
Division of Air Quality

&

U.S. Environmental Protection Agency, Region VIII
Office of Partnerships & Regulatory Assistance
Air & Radiation Program

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The technical comments herein are adopted on the record &
for purposes of public comment submittal to UDEQ-DAQ by:

Utah Physicians for Healthy Environment (UPHE) &
Western Resource Advocates (WRA)

This document available on the internet at:
http://www.sagady.com/workproduct/hollyrefinerynsr2.pdf

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1 Introduction

This document is an independent technical review and comment prepared by Alexander J. Sagady & Associates for filing in the matter of a Utah Department of Environmental Quality Division of Air Quality (UDEQ-DAQ) Draft Approval Order for the Holly Refinery in Woods Cross, UT. The review and comment address the present Draft Approval Order, the UDEQ-DAQ Source Plan Review and the final Revised Notice of Intent filed by Holly Refining and Marketing Company (here and after referenced as "Applicant") in 2013 and earlier NOIs filed in 2012. This matter concerns the modification and expansion of refinery process equipment at the Woods Cross facility.

This independent review and workproduct was authorized and commissioned by Utah Physicians for a Healthy Environment (UPHE) & Western Resource Advocates (WRA). Both UPHE & WRA adopt the technical comments and review provided in this workproduct as parties filing such comments with UDEQ-DAQ during the public comment period on the pending Draft Approval Order for the Holly Refinery.

2 Comments Addressing the Holly Refinery Source-Wide Plant Review and Multiple Emission Units or Process Groups

2.1 Applicant's "Notice of Intent" Submittal to UDEQ-DAQ is Incomplete for its Failure to Address Hydrogen Sulfide, Total Reduced Sulfur and Sulfuric Acid Aerosal as Required NSR-Regulated Pollutants in the Application-Required New Source Review (NSR) Analysis

Hydrogen sulfide (H2S), total reduced sulfur (TRS) and sulfuric acid aerosal (H2SO4) are substances that are present within or produced by petroleum refinery processes. H2S & TRS are common components of overhead process gases from petroleum refinery atmospheric and vacuum distillation towers and in downstream refinery gas management and sulfur recovery systems. As such, H2S and TRS will be released in fugitive and stack emissions from process equipment managing refinery fuel gases and acid gas processing.

H2SO4 is a component of flue gases from refinery heaters, boilers, flares and FCC unit catalyst regenerator/coke combustion process units.

H2S, TRS and H2SO4 are pollutants that are subject to one or more New Source Performance Standards published by U.S. EPA under Section 111 of the Federal Clean Air Act.

Commentors find that because these three pollutants are regulated by various federal NSPS standards published under Section 111 of the Clean Air Act, each of H2S, TRS and

H2SO4 as pollutants must be considered by UDEQ-DAQ as meeting the definition of the identity of a "Regulated air pollutant" as provided under R307-101-2, Definition of "Regulated air pollutant."

Further, Commentors find that these three pollutants must be considered as being "Subject to regulation" under provisions of UDEQDAQ's R307-405-(9) rules to implement the federal Prevention of Significant Deterioration (PSD) requirements as specifically provided under the R307-405-3(9) definition of "Subject to regulation."

The Applicant was required to provide information on stack and fugitive emissions of H2S, TRS and H2SO4 since these emissions are necessary for determinations pursuant to R307-405-15 and 40 C.F.R. §52.21(n)(1). The Applicant failed to provide the required information necessary for a determination under the rule. Such information is necessary to determine whether project-related emissions and any subsequent step 2 netting analysis with contemporaneous increases and decreases of these pollutants.

In addition, since Best Available Control Technology (BACT) is deemed as an 'emission limitation' under federal and state definitions of BACT, the determination of whether BACT for these regulated pollutants has been applied under R307-401-8 must necessary consider emissions information on expected releases for H2S, TRS & H2SO4 as regulated pollutants, if significant emissions are present.

Even if Applicant's planned project would not cause a significant net emission increase pursuant to 40 C.F.R. §52.21(b)(23)(i), UDEQ-DAQ is still under the obligation of determining and ensuring that Best Available Control Technology (BACT) has been applied to facility emissions of H2S, TRS & H2SO4 under UDEQ-DAQ's approval order decision standards under R307-401-8(1)(a). In carrying out that determination and ensuring that source operation will comply with such a BACT determination, UDEQ-DAQ must necessarily set an emission limitation reflecting such a BACT determination for H2S, TRS & H2SO4 that reflects a BACT determination for these pollutants at each facility emission unit. Failure to set such emission limitations means there are no assurances that BACT has been applied at the facility for H2S, TRS & H2SO4 emissions and no way for UDEQ-DAQ to enforce such a BACT determination.

In the present matter, neither the Applicant nor UDEQ-DAQ have ensured their submittals and decisionmaking reflects the required process and performance under the UDEQ-DAQ rules as set forth above for these regulated pollutants.

2.2 Neither the Applicant Nor UDEQ-DAQ Have Addressed Particulate Matter (PM) Emissions During Emission Characterization, Project-Related Emission Increases, Netting and Net Increase Calculations and in the Required BACT Determinations; the Refinery Onsite Road Network is an Emission Unit Not Listed in the Draft AO Approved Installations and Applicant Plans to Increase Site-Road-Related PM, PM-10 & PM-2.5 Emissions Through a Physical Change or Change in the Method of Operation of this Emission Unit

While the Applicant submitted some PM 2.5 and PM 10 emissions information, the Applicant failed to address PM emissions. PM is a "Regulated air pollutant" as provided under R307-101-2, Definition of "Regulated air pollutant" and is "Subject ot regulation" under R307-405-3(9).

The Applicant plans very large increases in truck deliveries of the waxy crude and the facility will also have increased truck traffic resulting from increased product shipments. Applicant's site road network is a PM, PM-2.5 and PM-10 emitting source and the Applicant plans a physical change or change in the method of operation of this emission unit in a manner that will increase site emissions through its plans to increase truck deliveries of waxy crudes.

The emission unit change with the change in the method of operation of the site road network is thus a physical change or change in the method of operation requiring evaluation in new source permitting. Because the refinery is changing the primary method for gaining crude oil deliveries from use of pipelines to use of crude delivered in tanker trunks, such a change is not merely an exempted increase in the process rate of the road network but a fundamental change in the nature of the use of the site road network for purposes of crude deliveries.

The Applicant did not acknowledge or characterize the increase in emissions of PM, PM-10 and PM-2.5 from increased truck traffic on refinery paved and/or unpaved roads. The Application contains no fugitive PM, PM-10 or PM-2.5 BACT controls on site-wide fugitive emissions from vehicle traffic, notwithstanding the increase in emissions from this emission unit. Applicant's submittal contains none of the information necessary to determine uncontrolled and controlled site road network fugitive emissions of PM, PM-10 and PM-2.5.

In light of this comment, UDEQ-DAQ must not approve the Draft Approval Order unless and until the Applicant has fully identified and characterized PM emissions from all site emission units and BACT-level controls on PM emissions have been determined. UDEQ-DAQ must insist the Applicant submit new information on site roads and expected vehicle traffic on site sufficient to characterize baseline actual emissions of PM, PM-10 and PM-2.5 from site roads and all increases in such emissions caused by increasing truck traffic at the site from project-related activities. Such a determination will require legible maps of the road network, information on routes of ingress and egress of vehicles, loaded and unload vehicle weights, numerical truck trip information, information on road pavement status, the locations of all truck terminal and loading racks facilities at the site and methods of site road fugitive emission control reflecting BACT.

UDEQ-DAQ fails to require Applicant to properly analyze and justify their application in addressing Applicant's PM emissions from each site process and emission unit when PM is an NSR-regulated pollutant. UDEQ-DAQ also fails, both in the present case and routinely for other facilities as well, to recognize road networks as emission units and to recognize controls on fugitive emissions from road networks to be BACT emission limitations that must be established in permits. The UDEQ-DAQ failure to recognize on-site road networks as emission units for PM-10 and PM-2.5 analysis and failure to address PM as a regulated pollutant all means that Applicant's netting analysis is incomplete, erroneous and non-approvable.

The UDEQ-DAQ failure then to enforce the proper documentation and demonstration of a significant emission increase and a significant net emission increase in the netting analysis is yet another problem of chronic unlawful UDEQ-DAQ air quality permitting programmatic operation.

To summarize -- by negligent inaction endemic to the UDEQ-DAQ air quality permit issuance program, UDEQ-DAQ prejudicially excuses Applicant and others from requirements contained in binding air rules in a manner favoring emissions sources and against the interests of public health and environmental protection. And, the negligent inaction ignoring regulated pollutants and emission units under the rule is an act of UDEQ-DAQ scientific misconduct in carrying out its air pollution control duties.

2.3 Applicant's Consideration of Baseline Actual Emissions for Purposes of Affected Unit Emission Increase and Net Emission Increase Determinations in Applicant's Section 3 Emissions and Netting Analsyis Review Failed to Consider Increase Flare-Related SO2 Emissions Caused by Refinery Site Wide Expansion of Process Units and Failed to Address SO2 Flare Emission Contributions to Site-Wide SO2 Emissions

In determining baseline actual emissions for contemporaneous increases and decreases, 40 C.F.R. §52.21(b)(48)(i)(a) requires Applicant to include emissions associated with startups, shutdowns and malfunctions in the baseline actual emissions determination.

During startups, shutdowns and malfunctions petroleum refinery process units will discharge untreated refinery process gases containing significant quantities of VOCs, HAPs and sulfur compounds to flare gas collection systems.

Both the physically modified and unmodified flares at this site will have increased rates of annual gas flow throughputs directed to the elevated flares on an annual basis over previous and historical operations with less physical capacity for production processes at the refinery site in the initial configuration.

Applicant submitted information shown in Attachment #6 on flaring emissions due to upsets in Section 3.6 of the final Revised NOI of July, 2012. The information indicates upset emissions of 120 tons per year of sulfur dioxide for each of the two remaining site flares. Commentors could not locate any emission calculations showing the derivation of the SO2, NOX VOC and CO emissions provided by Applicant in Section 3.6.

Applicant identified the emission determinations as "proposed flare emissions" from upsets for the north and south flares. Commentors can only assume that Applicant intended the emissions information as what the flares would emit in the future final configuration of the facility. Applicant identified the emission levels as upset emissions, but it is not clear whether or not the listed upset emission totals for the flare also include flaring from startup and shutdown events as well.

Because the 120 tons of SO2 per year per flare is identified as "proposed flare emissions," the emissions provided cannot be deemed to be "baseline actual emissions" for flaring purposes. Applicant must provide and submit a "baseline actual emissions" determination with justifying emission calculations in order to justify any future "proposed flare emissions" for the facility.

Commentors find that the lack of a "baseline actual emissions" determination for the existing flare system means that Applicant has failed to properly integrate flare-related SO2 emissions from upsets, malfunctions, startups and shutdowns into the Table 3-3 emission increase from affected units determination and the Table 3-9 net emission increase and contemporaneous emission increase and decrease review. In determining "baseline actual emissions" in the manner required by 40 C.F.R.§52.21(b)(48) and in carrying out a "net emission increase" determination under 40 C.F.R.§52.21(b)(3)(i), Applicant must consider malfunctions, upset, startups and shutdowns in determinations made pursuant to 40 C.F.R. §52.21(b)(48)(i)(a). Applicant has not complied with this burden in the present matter since Table 3-3 and Table 3-9 failed to include increased flaring emissions as an identified and characterized emission increase associated with the increased number of operational process units in the final refinery configuration.

The failure to properly consider flare-related SO2 emissions that Applicant has admitted in the significant emission increase and the significant net emission increase and throughout the netting analysis is scientific misconduct on the part of the Applicant to properly carry out such analysis in the manner required.

The failure to consider flare-related SO2 emission that Applicant has admitted at 120 tons of SO2 per year renders Applicant's conclusions in its SO2 netting analysis as erroneous, incomplete and non-approvable.

2.4 Table 3-4 and 3-5 NO2 Reference

Table 3-4 and 3-5 in the 2012 NOI are integral parts of Applicant's emission increase and net emission increase analysis under 40 C.F.R. §52.21(a)(2)(iv)(a). Both of these tables have emission change columns labelled as "NO2." While NO2 is a regulated pollutant, using total NO2 instead of Total NOX in such emission increase analysis constitutes error since NOX addresses all species of nitrogen oxides that have a role in photochemical ozone formation and the netting decision must necessarily address NOX and not NO2 individually.

The column legend and column entries in Tables 3-4 and 3-5 must address total NOX and not just NO2.

2.5 Facility Configuration and Operations in Compliance with Applicant's Notice of Intent

No provision of the Draft Approval Order provides that Applicant shall construct and operate the new and modified refinery process equipment in a manner that is consistent with Applicant's Notice of Intent.

Specifically, no provision of the UDEQ-DAQ Draft Approval Order states that the Applicant shall install, operate and maintain process equipment, emission control devices, stack/vents and monitoring equipment in a manner that comports with Applicant presentations in the Notice of Intent. For example, the Draft Approval Order contains no federally enforceable provision requiring that vent stacks and release heights on the vent stacks be constructed in a manner to reflect the facility as it was modeled with the required vent stack height and location listed in the NOI and that such release heights shall be maintained.

2.6 Applicant's Notice of Intent as Revised in July 2012 Contains Significant Errors on the Matter of the Specific Start of the Contemporanous Period

Under applicable regulations, the contemporaneous period for considering increases and decreases in NSR netting analysis is established in the following manner:

> "(ii) An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between: (*a*) The date five years before construction on the particular change commences; and (*b*) The date that the increase from the particular change occurs."[1]

[1] 40 C.F.R. §52.21(b)(3)(ii)

Because of the provisions of that rule, it is error for the Applicant to claim that the contemporaneous period began on May 25, 2007[2] and Applicant mis-states the effect of application of 40 C.F.R. §52.21(b)(3)(ii) on their own situation by saying the "...contemporaneous period starts five years from the date of the NOI until the AO is signed, that is May 25, 2007."

Commentors deny the validity of Applicant's claimed beginning of the contemporaneous period in the present Approval Order action. No part of UDEQ-DAQ's decision on both Approval Order issuance generally and UDEQ-DAQ air quality review may rely on Applicant's improper and erroneous characterization of the contemporaneous period required for use under 40 C.F.R. §52.21(b)(3)(ii).

UDEQ-DAQ must insist that the Applicant conform its setting of the beginning of the contemporaneous period to a date that is 5 years prior to the expected start of construction which would be a time certain during the present year, 2013. After doing so, UDEQ-DAQ must insist that the Applicant revise their submittal to ensure that all contemporaneous emission increases and decreases are considered on the proper time boundaries of the contemporaneous period.

2.7 UDEQ-DAQ Must Deny Applicant's Notice of Intent in Light of Applicant's Insistence that Emission Increases and Decreases Taking Place as a Result of the June 8, 2007 "Modernization Project" are to be Impermissibly Considered as Taking Place as of the Time of the June 8, 2007 Approval Order Issuance Date and Not at the Time of Commencement of the Operations of Authorized Equipment

Applicant is under a duty to find, consider and include all contemporaneous emission increases and decreases under 40 C.F.R. §52.21(b)(3)(i)(b) in the required determination of the amount of net emission increase and to determine whether such a net emission increase is significant under 40 C.F.R. §52.21(b)(23)(i).

However, Applicant has admitted either not considering or leaving out all emission increases and decreases authorized under the June 8, 2007 Approval Order for the refinery modernization project.

> "Thus Holly feels that since an approval order for the current proposed project will not be issued under Fall of 2012 at the earliest and that the AO for the modernization project was dated June 8, 2007, the emissions from the

[2] See p. 3-9 last paragraph and p. 3-10 last paragraph, 2012 NOI

> modernization project fall outside the five years before construction can commence and not considered contemporaneous."[3]

The Applicant does not explain why the June 8, 2007 date is somehow outside of the contemporaneous period that Applicant insisted started on May 25, 2007. Applicant's insistence that emission increases from the June 8, 2007 modernization project authorized by that particular Approval Order are excluded as being creditable during the contemporaneous period violates specific rule requirements stating when contemporaneous emission increases are considered creditable. EPA's rule provides:

> "(viii) An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed 180 days."[4]

This provision means that Applicant's assertion that emission increases resulting from the June 8, 2007 AO be considered as taking place on the date of the AO adoption is an erroneous regulatory determination.

Under the provisions of 40 C.F.R. §52.21(b)(3)(viii), the emission increases occurring as a result of physical changes authorized under the June 8, 2007 AO must be considered as occurring **at the time of emission unit and or process unit startup** that had changed or increased emissions **as of the operational startup date** after completion of physical changes.

UDEQ-DAQ must disallow Applicant's claims that emission increases under the modernization project must somehow be considered as having occurred at the June 8, 2007 AO approval date [for contemporaneous analysis purposes] rather than at the time of project equipment and emission unit startup after construction was completed after the date of AO approval, as is required by 40 C.F.R. §52.21(b)(3)(viii).

In response to this comment, Commentors request that UDEQ-DEQ list in its reply to the comment which units and modification, including a listing of all emission increases and decreases that that were authorized pursuant to the 2007 permit and which will occur/commence under actual present plans of the Applicant during the newly defined contemporaneous period determined at final permit issuance. Of the list mentioned in the prior sentence, Commentors request that UDEQ-DAQ list each of the pieces of equipment and changes as shown by an emission increase or decrease that will occur during the contemporaneous period but which have been excluded from Applicant's netting analysis in the contemporaneous period.

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[3] Applicant July, 2012 amended NOI on Holly Refinery, Page 3-11, middle paragraph

[4] 40 C.F.R. §52.21(b)(3)(viii)

2.8 All of Applicant's Notice of Intent Submittals are Incomplete Because UDEQ-DAQ Failed to Require Applicant to Properly Include Process Flow Diagrams and UDEQ-DAQ New Source Review Forms Necessary for Proper Source Characterization and for Proper UDEQ-DAQ Permit Issuance Procedure in a Manner Prejudicial to Public Comment and Participation

Applicant's facility contains several process and emission units that are all interconnected and related to each other through direct flow of process hydrocarbon gaseous and liquids throughout the facility. However, nothing in Applicant's final Revised Notice of Intent shows or explains the relationships of all of the refinery's process units, emission units and control units in a graphic form and which is a standard element of required information..

Applicant failed to submit UDEQ-DAQ New Source Review Forms 1, 1a, 2, 4, 11, 12, 19 and 22 which all should be required and provided

Applicant's submitted Notice of Intent is incomplete and Applicant's requested UDEQ-DAQ Approval Order is non-approvable on a technically incomplete application because of the failure of Applicant to submit a process flow diagram showing all refinery process and emission units and the process flow relationships between each of these units. Commentors caused the filing of a public records request to UDEQ-DAQ specifically requesting such a process flow diagram and none was provided from the file by UDEQ-DAQ. UDEQ-DAQ failed to require submission of information required for NOI evaluation and AO issuance decisions.

Applicant submitted neither a process flow diagram showing the pre-NOI process flow configuration of the facility, nor a process flow diagram showing future final configuration of the facility after all authorized modifications have been completed.

UDEQ-DAQ cannot evaluate Applicant's emission characterization claims by process and emission unit for the subject facility without understanding the relationships between all process units, emission units and emission control units.

In particular, the failure to have a process flow diagram showing the refinery facility means that UDEQ-DAQ cannot competantly assess or analyze Applicant's claims or Applicant's failures of disclosure concerning contemporaneous emission increases and decreases at non-modified process and emission units after the significant overall refinery expansion being undertaken by Applicant, as discussed in the next section below

Documents labeled by UDEQ-DAQ as "Notice of Intent" documents from the Applicant that UDEQ-DAQ provided to the public do not contain UDEQ-DAQ-NSR Section Form 1, 1a and 2 that address source processes and operating information required by the agency to properly make a determination on Applicant's submitted final Revised Notice of Intent. UDEQ-DAQ-NSR Section Form 1 indicates that a Utah NSR applicant is supposed to contain a "Detailed description of project **including process flow diagram** (See Forms 2-23)"[5] (emphasis added)

Applicant's Notice of Intent cannot be properly reviewed and approved unless and until the Applicant submits process flow diagrams showing both present and future configuration of the all refinery-site process, emission and emission control units. Failure to submit the required process flow diagram renders the application technically incomplete and non-approvable.

2.9 Applicant Failed to Properly Evaluate and Characterize Contemporaneous Emission Increases Arising at Applicant's Non-Modified, Existing Process and Emission Units as a Result of Increased Process Utilization Rates Caused by Facility Process Expansions and Other Factors Arising in Applicant's Modernization Project

The Applicant is required to conduct a determination of the 'net emission increase' under 40 C.F.R. §52.21(b)(3)(i). Under such a determination, the provisions of the rule requires that:

> "any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable."[6]

This provision requires that all such creditable and contemporaneous emission increases and decreases be considered in the 'net emission increase' determination. Nothing in 40 C.F.R. §52.21(b)(3)(i)(b) states that the emission increases and decreases must necessarily come from a physical change or change in the method of operation at an existing emission unit that is not new or modified.

Under the language of the rule, "any other increases and decreases" includes all such emission increases and decreases, including those emission increases and decreases at existing, non-modified emission units whose processes are operated at a different production, heat generation or throughput rate in the final configuration of the facility upon commencement of operation of all new and modified emission units.

Applicant's final Revised Notice of Intent included review of the matter of so-called "Process Support Units" in Section 2.3 of Applicant's final Revised Notice of Intent. Applicant stated:

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[5] UDEQ-DAQ Form 1 on p. 2 under "Process Information" available at http://www.airquality.utah.gov/Permits/FORMS/October2011/Form1NOI.pdf

[6] 40 C.F.R. §52.21(b)(3)(i)(b), in part

> "The installation and operation of the proposed new or modified equipment at the Holly Refinery will impact some of the refinery's current operation and existing equipment. The following sections discuss the impacted areas."[7]

Applicant's submittal then shows 7 specific sections covering "Fuel Gas," "Cooling Towers," "Flare," "Loading/Unloading Facilities," "Storage Tanks," "Wastewater Treatment and Sewer," and "Removal of Frozen Earth Propane Storage."

Commentors find that Applicant's Section 2.3 failed to provide process/emission unit specific information sufficient to calculate and determine all contemporaneous emission increases and that emission tables in the subsequent section of Applicant's final Revised Notice of Intent failed to include required contemporaneous emission increases that will occur at non-modified existing emission and process units at the refinery. The failure of Applicant's emission tables in Section 3 of Applicant's final Revised Notice of Intent to properly list and determine all contemporaneous emission increasess at non-modified process and emission units means Applicant's submittal is non-approvable because of failure to comply with 40 C.F.R. §52.21(b)(3)(i)(b).

Commentors also note Applicant's failure to submit the required process flow diagram notice in a prior section of this comment. Such a failure to submit required information obstructs review by the public of Applicant's overall portrayal of emission changes at their facility because such process flow diagrams are necessary to properly evaluate the relationships between all process units, emission units and emission control units.

In the following subsections, Commentors address each of Applicant's specific deficient subsections under Section 2.3 and related Section 3 emission table information to show that Applicant failed to properly consider and determine all contemporaneous, creditable emission increases expected from future operation of the refinery in the final future configuration as modified.

2.9.1 Applicant's Section 2.3.1 "Fuel Gas" Process Support Group Analysis Submittal and Related Section 3 Emission Tables Failed to Show a Proper and Required Determination Under 40 C.F.R. §52.21(b)(3)(i)(b) for Contemporaneous Creditable Emission Increases and Decreases

The Applicant is proposing a large expansion of their facility with several new process groups and emission units in additing to the present operations at the refinery. Such an expansion will involve a significant expansion of the refinery fuel gas system network to supply fuel to new and modified heater and boilers in the second FCCU process train and at other locations.

[7] Holly Refining and Marketing, final Revised Notice of Intent, Section 2.3, p. 2-9

Because some of the existing heaters and boilers that are not modified serve process and emission unit functions served by, shared by or in coordinated operation with new and modified refinery process equipment in the future final configuration of the facility, operation of the refinery in its future final configuration means that utilization of such existing heaters and boilers may increase in the future refinery configuration.

The emission increases over baseline actual emissions from non-modified heaters and boilers arising from increased heat duty rates for the pre-existing, non-modified heaters and boilers must be considered creditable because they will occur at the existing units at the time that the new/modified process units actually start up that make additional demands on the pre-existing, non-modified heaters and boilers. As a result, the increased emissions from increased utilization of existing and non-modified heaters and boilers must be considered with all other contemporaneous creditable emission increases and decreases.

For example, Applicant's new process equipment is likely to cause increased utilization of process units in hydrogen generation, catalytic refining units, sulfur plant units or in catalytic refining units.

Applicant's one paragraph Section 2.3.1 and together with related emission tables in Section 3 do not constitute a valid and required determination of the effect of the expanded facility's process and emission units on pre-existing, non-modified refinery heaters and boilers. Because Applicant's Section 2.3.1 is deficient and is not a valid determination of how operation of the new and modified emission units will affect either likely or maximum potential non-modified unit process utilization rates at the non-modified heaters and boilers, there is no physical information basis in Applicant's submittal allowing for the required determination of contemporaneous, creditable emission increases from Applicant's non-modified and pre-existing heaters and boilers.

A valid determination for addressing contemporaneous emission increases and decreases from non-modified heaters and boilers would necessarily require a showing of the following specific data elements:

- Demonstrate the present annual heat duty and/or the annual heat duty associated with the emissions inventory calculation for the selected 2 year annual average determined under "baseline actual emissions" before the authorized changes in the present Approval Order matter to the refinery occur for each and every pre-existing and non-modified heater and boiler.

- Determine the predicted annual heat duty for each and every pre-existing, non-modified heaters and boilers at Applicant's facility that will occur under a most likely operational utilization scenario and also a separate utilization determination at the maximum overall refinery production rate or crude feed rate.

- Determine the contemporaneous emission increases and decreases over baseline actual emissions occurring at each non-modified process and emission unit for purposes of finding all creditable, contemporaneous emission increases and decreases for purposes of submitting the required analysis under 40 C.F.R. §52.21(b)(3)(i) that UDEQ-DAQ must require of Applicant.

No such analysis is contained in Applicant's submittal and such a failure by Applicant means the requested Approval Order cannot be issued because the proper netting analysis was not carried out. Applicant's netting analysis must consider all contemporaneous emission increases and decreases for all NSR-regulated pollutants. UDEQ-DAQ must reject Applicant's submittal since no analysis was conducted of contemporaneous emission increases and decreases that occurred from changes in utilization rates for non-modified process and emission units during the contemporaneous period.

2.9.2 Applicant's Single Paragraph Section 2.3.2 Disclosure of Cooling Tower Changes Fails to Provide Sufficient Information to Determine Contemporaneous Creditable Emission Increases from Non-Modified Portions of Existing Cooling Towers

Nothing in Applicant's single paragraph Section 2.3.2 disclosure provides physical and operational information concerning non-modified cooling tower units sufficient to determine all pollutant increases and descreases under conditions of increased heat duty for the non-modified units in serving new/modified process units in the final future configuration of the refinery. Such information is necessary to accurately determine contemporaneous creditable emission increases from higher utilization of non-modified cooling tower units. Failure to provide such future operating information about existing, non-modified cooling tower units is a basis for Approve Order denial for failure to properly carry out a determination of contemporaneous creditable emission increases and decreases under 40 C.F.R. §52.21(b)(3)(i).

2.9.3 Nothing in Applicant's Section 2.3.3 Disclosure Concerning Flares provides Sufficient Information to Determine Contemporaneous Creditable Emission Increases at Non-Modified Flare Emission Units

Applicant's Section 2.3.3 submittal provides no basis for determining the future physical level of utilization of non-modified (or modified) flare units caused by the facility expansion. As a result, there is no basis for determining if there will be contemporaneous creditable emission increases are such units as required for determination under 40 C.F.R. §52.21(b)(3)(i).

2.9.4 Nothing in Applicant's Section 2.3.6 Section of Wastewater Treatment and the Refinery Wastewater Sewer Sytem Provides Sufficient Physical Information to Quantify the Effect of the Refinery's Expansion on Contemporaneous, Creditable Emission Increases and Decreases from Such Pre-existing, Non-modified Refinery Emission Units under 40 C.F.R. §52.21(b)(3)(i)

Applicant's Section 2.3.6 review of wastewater treatment and sewer process and emission units and Applicant's Section 3 emission tables contains no information sufficient and necessary to determine all regulated pollutants either from the existing or future wastewater treatment and wastewater sewer emission unit at the facility.

As a result, nothing in Applicant's submittal provides information sufficient to determine contemporaneous, creditable emission increases and decreases from the non-modified portions of the refinery wastewater treatment and process wastewater sewer system in the future final configuration in the manner that 40 C.F.R. §52.21(b)(3)(i) requires for determination.

Applicant's submittal in Section 2.3.6 and the failure of the Applicant to characterize wastewater treatment and wastewater sewer related emissions in any manner at all in Tables 3-3 through 3-9 of Applicant's Notice of Intent, either for purposes of emission determination on the pre-existing configuration of the refinery and on the future configuration of the facility, means the submittal contains none of the required information necessary on either existing or new refinery wastewater and refinery sewer emission units for emission characterization.

Not only is Applicant's submittal insufficient for emission characterization and determination, Applicant's submittal includes a spurious discussion of water supply and water conservation which are irrelevant to emission determination for sewers and wastewater treatment plants. The studies Applicant addresses do not address the increased rate of generation of process wastewater from the new and modified process and emission units added with expansion of the refinery.

Finally, in addition to increased emissions from non-modified portions of the refinery oily wastewater sewers and the wastewater treatment plant, Applicant will be constructing a new network of new oily wastewater sewers attached to the new process equipment being constructed. Applicant failed to quantify any such new emissions from new sewers and significantly increased throughput through the current wastewater system.

2.10 Applicant's Section 3 Emission Characterizations Addressing Emissions of Volatile Organic Compounds and Hazardous Air Pollutants from Cooling Towers

2.10.1 In the 2012 NOI, Applicant's Claim of 48.1 Ton Per Year of VOC Emission Reduction from Cooling Towers 4-8 is a Spurious and Unsupported Emission Characterization for Volatile Organic Compound Net Emission Increase Analysis

Applicant's 2012 NOI claimed a 48.1 ton per year emission reduction from Cooling Tower 4-8 solely based on commencing a cooling water VOC periodic monitoring program. Applicant failed to provide any details that specified when the cooling water VOC monitoring program began, how often monitoring is carried out and a complete history of the effect of control actions on annual VOC and HAP emissions at Cooling Towers 4-8.

Applicant submitted annual emissions information for all of the cooling towers as shown in Attachment #8. For the 10 year period from 2001 through 2010, the data do not show any years when the annual emissions predicted have been significantly reduced from the commencement of the alleged cooling water VOC monitoring program or other VOC RACT control. If the cooling water monitoring program effectively reduced VOC emissions from these units, then Applicant has not claimed, shared or demonstrated the effect of any significant reductions in Applicant's submitted annual emission inventories.

Attachment #9 shows Applicant's 2012 emission calculation sheet for VOC from cooling towers. The calculation sheet indicates that the VOC baseline of 2008-2009 is 52.95 tons per year. Applicant determined emissions based on a controlled level of 4.87 tons of VOC per year based on AP-42 controlled recirculating cooling water VOC. Applicant did not use data from their own monitoring program to determine the controlled level of emissions from the existing cooling towers. Applicant's cooling tower emission calculation sheet shows a 48.08 ton per year VOC emission reduction which was used in Table 3-9 net emission increase analysis.

This Applicant-claimed cooling tower VOC baseline emission level conflicts with the annual emission inventory Applicant claimed to have submitted in Attachment #8. That data shows 2008 VOC emissions of 44.81 tons per year and 2009 VOC emissions of 46.14 tons per year for a 2 year average of 45.5 tons per year for VOC and not 52.95 tons per year as Applicant claims in the cooling towers calculation sheet. If the controlled level in the calculation sheet of 4.87 tons VOC per year were applied, the reduction available for potential consideration would be limited to 40.6 tons of emission reduction.

All of Applicant's emission characterization must be questioned in the absence of both submittal and usage of actual cooling water VOC analytical work carried out and the lack of details about the level of controlled emissions and uncontrolled emissions based on Applicant's own cooling water VOC analytical activities.

Implementation of the cooling water VOC monitoring is a Reasonably Available Control Technology (RACT) whose use is or should be considered as a Utah State Implementation Plan requirement for ozone control at Applicant's facility. Attachment #7 contains a listing of RACT controls at Applicant's facility that Commentors located on the UDEQ-DAQ website. That RACT listing addresses Applicant's problems with releases of propane from the cooling towers in 2008 as a result of heat exchanger leaks. However, Applicant's 2008 emission inventory in Attachment #8 does not show or fails to indicate any kind of unusual 2008 VOC emissions as cited in the RACT document.

Since cooling water VOC monitoring of sufficient frequency and proper format is a RACT control as admitted by the Applicant, Applicant should not have taken any credits in Table 3-9 of the 48.1 tons of VOC emission reducation listed for emissions that would have exceed a RACT level of control for the historical baseline used. Applicable requirements at 40 C.F.R. §52.21(b)(48)(ii)(b) & (c) require that the average rate of emissions must be adjusted downward to reflect source operation while operating above a RACT limit or to otherwise adjust downward baseline emission reductions that would have violated a RACT level of control had it been in place in the past. Applicant failed to carry out any such required reduction in the 'baseline actual emissions' noted for the 48.1 tons of VOC emission reduction claimed from the commencement of cooling tower water VOC analytical monitoring in violation of 40 C.F.R. §52.21(b)(48)(ii)(b) & (c).

Applicant's claimed 48.1 tons emission reduction from cooling towers 4-8 should be disallowed until such time that the record adequately supports such a determination. Moreover, Applicant's description contained in Attachment #7 of refinery operations while the degraded facility heat exchangers allow propane process material to enter the cooling water system must be considered poor air pollution control practice. Measures taken to remedy acts of Applicant's poor air pollution control practices with propane in cooling water systems cannot be allowed as contemporaneous emission reductioon credits under 40 C.F.R. §52.21(b)(48)(ii)(b) & (c).

2.10.2 Applicant's Section 3 Emission Increase and Net Emission Increase Tables Contain Erroneous Specification of Volatile Organic Compound and Hazardous Air Pollutant Emissions from Cooling Tower #11

Applicant's 2012 Revised Notice of Intent addresses emissions of volatile organic compounds (VOC) and hazardous air pollutants (HAP) from Cooling Tower #11 in Tables 3-3 and 3-9. Table 3-3 indicates 1.56 tons per year of VOC and 2.07 tons per year of HAP. Table 3-9 indicates 1.6 tons per year of VOC and 2.07 tons per year of HAP.

Applicant's Table 3-3 and 3-9 line entries for Cooling Tower #11 are erroneous as depicted in those tables since the table-reported results conflict with Applicant's own Cooling Tower #11 Emissions calculation sheet which indicates 2.39 tons per year of VOC and 3.17 tons per year of HAP.

Applicant's Table 3-3 and 3-9 must be revised to correct this problem and all other emission tables in Section 3 that depend on total results in Tables 3-3 and 3-9 must be revised to conform to corrections of the Cooling Tower #11 VOC and HAP emission characterizations.

Commentors find that Applicant has not provided a HAP emission estimate for chloroform and methyl chloride which may be present in reciculating cooling water system.

2.10.3 Applicant's 2013 Netting Demonstration Impermissibly Claims a 39.28 Contemporaneous Emission Reduction Thus Rendering Applicant's VOC Netting Analysis as Erroneous and Showing Applicant's Planned Project and Modification as Significant Emission Increases and Significant Net Emission Increases

The final netting table spreadsheet indicates a claimed VOC contemporaneous emission reduction from cooling towers #4-#8 of 39.28 tons per year. Applicant claims this 39.28 ton per year emission reduction from a baseline emissions from 2007-2008.

Applicant 2013 NOI submittal amendment thus again makes a claim that this emission reduction results directly from Applicant commencing a required RACT VOC control that Applicant themselves admit and identify as a RACT control measure. See Attachment #7.

Although Applicant admits the 39.28 ton per year VOC claimed emission reduction came from a VOC RACT control measure, Applicant nevertheless failed to adjust downward the claimed VOC emission reduction as is required under 40 C.F.R. §52.21(b)(48)(ii)(b) & (c). Commentors assert that none of the 39.28 ton per year VOC emission reduction can be credited during the contemporaenouse perior because the effect of 40 C.F.R. §52.21(b)(48)(ii)(b) & (c) would be to disallow the entire 39.28 ton per year reduction as non-creditable.

Under the circumstance of disallowing the 39.28 ton per year reduction, correct netting analysis of VOC emissions from the facility shows both a significant emission increase from the project and an overall significant net emission increase -- thus making the modification a major source for VOC emissions.

2.11 Condition II.B.1.b in the Draft Approval Order is Too Vague to be Enforceable

The third sentence of Condition II.B.1.b is vague and indeterminate to be enforceable. The provision should be replaced with one that uses equations and lists all parameters to be used in such equations instead of the vague provision proposed by UDEQ-DAQ.

2.12 Production Rates During Compliance Stack Tests

The last sentence of Condition II.B.1.b provides for stack testing to be done at 90% of the maximum production rate under a three year average. This means that Applicant is being allowed to conduct stack tests at times when the tested equipment will be operating a less than 95% of the physicaloperational capacity of the unit. UDEQ-DAQ's allowance for Applicant to test their equipment at a production rate less than a maximum potential to emit rate fails to properly regulation the subject facility.

2.13 Tanks

2.13.1 VOC Emissions and Waxy Crude Handling, Transfer and Storage

Applicant insists no emissions will occur from waxy crude handling, transfer and storage at nominal ambient temperatures. However, Applicant's claim that waxy crude will not release VOC emissions as a solid at room temperatures does not address Applicant's actual handling of waxy crude.

Applicant cannot transfer and store waxy crude without subjecting this feedstock to elevated temperatures. When waxy crude is heated it will no longer be a solid, but a liquid and any lighter molecular weight compounds that are contained in the crude or form from thermal breakdown can be released from such liquids.

Applicant must address vapor pressures, crude mixtures, reduced sulfur compounds, HAP and VOC emissions from all of the waxy crude handling, transfer, loading and storage operations and such characterizations must address the temperatures to which the waxy crude is subject.

Applicant states:

> "IFR – Internal floating roof. Holly proposes to remove the floating roofs on Tanks 71 and 72 and use these tanks for storage of black and yellow wax crude. However, Holly may initially leave the floating roofs in place, because there has been some variation in the vapor pressure of this crude, and although it has not varied enough to require vapor control, further monitoring of the vapor pressure will be conducted prior to removal of the roofs. If the vapor pressure of delivered

> crude appears to drop to levels that would require vapor controls, the roofs will be left in these tanks, and Holly will address the need to install controls on the remaining waxy crude storage tanks."[8]

Applicant plans to remove floating roofs from tanks that will contain hot waxy crude, saying such tanks will have not emissions because waxy crude is a solid at room temperatures. Such a change is a physical change or change in the method of operation that must be addressed in facility emission increase and net emission increase determinations. Applicant should not be allowed to claim that zero emissions will result or that emission decreases will result from removing the floating roof from hot waxy crude tanks.

In addition, removing floating roofs from hot waxy crude tanks is an act likely to increase heat losses from the hot waxy crude as it exists in the tank in a manner that would increase fuel utilization in a facility undergoing a BACT review for GHG emissions.

2.13.2 UDEQ-DAQ Must Reject Applicant's Erroneous Claim VOC Emission Reduction from Removal of a Floating Roof

Applicant's 2012 netting review claims a 0.58 ton per year emission reduction for VOC from the Tank 71 and 72 so-called "conversion" discussed in the prior subsection.

UDEQ-DAQ should disallow at technically implausible such a claimed emission reduction alleged to be from removing a recognized form of air pollution control from a petroleum hydrocarbon storage tank.

2.13.3 The Approval Order Should be Amended to Contain a Section Addressing the Regulatory Status, Method of Emission Control and Monitoring-Inspection-Recordkeeping-Reporting Requirements for Tank Sources of VOC and HAP

No provision of the present permit regulates tank emissions. UDEQ-DAQ should include a section of the permit that establishes all state and federal regulatory requirements for the tanks, including control requirements. The section should address monitoring, inspection, recordkeeping and reporting requirements for tanks.

In particular, UDEQ-DAQ should require a specific minimum annual frequency for source tank inspections.

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[8] Revised NOI, July, 2012, p. 2-12 footnote for tank table.

2.14 Applicant Must be Required to Address Condensible Emissions from 4FCCU and 25FCCU Scrubber Control Units

Emission estimates for the wet scrubber controlled FCCU units appear to be filterable-only estimates and Applicant must be required to fully characterize both filterable and condensable emissions for these units. Applicant must provide total filterable plus condensible PM, PM-10 and PM-2.5 emissions for both FCCU units at the refinery for purposes of Applicant's Table 3-3 and 3-9 analysis for emission increases and net emission increase determinations for purposes of 40 C.F.R. §52.21(a)(2)(iv)(a) analysis.

2.15 UDEQ-DAQ Must Enforce Notice of Intent and Compliance Report Certification by the Applicant

Notice of Intent materials disclosed to Commentors did not contain a signed certification statement attesting to the accuracy of claims made in Applicant's final Revised Notice of Intent filed in July, 2012.

Applicant has not signed a UDEQ-DAQ NSR Section Form 1 certification statement attesting to the accuracy of its submitted Notice of Intent or a functionally equivalent statement submitted under certification standard by a designated corporate officer.

Applicant's NOI and requested UDEQ-DAQ approval order should be denied as not complying with EPA's state program element requirements for certification of the contents of a Title V permit application and certification of the veracity of compliance reports. EPA Title V programmatic regulations provide:

UDEQ-DAQ air quality permitting and Applicant’s specific permit application are subject to the requirements of 40 C.F.R. §70.5(d) in the matter of certification requirements for submitted application matters and compliance reporting and all other submission responsibilities. The provision states:

> “(d) Any application form, report, or compliance certification submitted pursuant to these regulations shall contain certification by a responsible official of truth, accuracy, and completeness. This certification and any other certification required under this part shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.” (40 C.F.R. §70.5(d))

This Title V regulation for air quality permitting in compliance with CAA Title V requirements is unlawfully systematically disregarded, both in the present case and in the rest of the UDEQ-DAQ Approval Order issuance program.

By failing to enforce 40 C.F.R. §70.5(d) in the State of Utah in Approval Orders binding on entities who have applied for such permits, the UDEQ-DAQ air quality program negligently acts as an enabler for any entity that decides to submit false or fraudulent permit applications and compliance reports in a manner that shields such conduct from potential civil or criminal liability and weakens the ability to enforce the Clean Air Act.

The UDEQ-DAQ programmatic non-enforcement approach to its responsibilities under 40 C.F.R. §70.5(d) implicit in enforcing CAA Title V requirements is a matter that should be visited by EPA Region VIII and the EPA Inspector General.

Commentors assert that UDEQ-DAQ must amend the proposed Approval Order to require that all compliance and monitoring reports and other presentations, submittals and filings by Applicant also be accompanied by the requirement for a signed certification statement consistent with Part 70 requirements for such certification.

Commentors assert that UDEQ-DAQ must deny Applicant's NOI unless and until the Applicant submits a suitable verification covering the entire history of its application submittals and presentations in the present matter.

2.16 Compliance Assurance Monitoring

UDEQ-DAQ must evaluate whether and how the facility will comply with compliance assurrance monitoring requirements of 40 C.F.R. Part 64 compliance assurrance monitoring requirements. UDEQ-DAQ cannot consider that the present permit compliance with CAA Title V requirements unless and until all emission units subject to the compliance assurrance monitoring requirements contained in 40 C.F.R. Part 64. Such requirements must be directly placed into permits for enforceability.

3 Specific Emission Unit Section

3.1 Emission Units 4FCCU & 25FCCU Catalyst Regenerators

3.1.1 UDEQ-DAQ's Proposed Approval Order for the Applicant's Facility Fails to Enforce Specific Requirements of the July, 2008 EPA Consent Decree Covering PM Emission Limitations for FCCU Unit 4 and Fails to Require Sufficient Monitoring Necessary to Assure Compliance with PM Emission Requirements from Applicant's FCCU Units 5 and 25

The July, 2008 EPA Consent Decree required the Applicant to comply with a PM ermission limitation at least as stringent as 0.5 lbs of PM per 1000 pounds of coke burned in 4FCCU's Catalyst Regenerator process.[9] Paragraph 33 required installation and commencement of operation of a wet gas scrubber at 4FCCU by December 31, 2012 that would allow the facility to comply with the 0.5 lbs of PM emission limitation.

Definition gg of the July, 2008 Consent decree defined PM as:

> "'PM' shall mean particulate matter as measured by 40 CFR Part 60 Appendix A, Method 5B or 5F."

Approval Order condition II.B.2.c as proposed fails to provide the PM emission limitation specifically required by the PM Consent Decree on Holly Refinery for FCCU Unit 4. Condition II.B.2.c specifies a **PM-10** emission limitations of 0.50 lb/1000 lbs coke burned for FCCU Unit 4 and 0.3 lb/1000 lb coke burned for Unit 25.

UDEQ-DAQ's attempt to substitute PM-10 as a pollutant for the Consent Decree PM emission limitation and to substitute different test methods for the consent decree-required EPA Method 5B or 5F determination is technical error and an act by UDEQ-DAQ to re-interpret and relax clearly required emission limitations binding on the Applicant under that Consent Decree.

UDEQ-DAQ is not at liberty to re-interpret the EPA Consent Decree in a manner that relaxes PM emission limitation requirements to a PM-10 limitation without having EPA's consent to do so. Neither is UDEQ-DAQ at liberty to allow the Applicant to substitute PM-10 analytical methods (such as EPA Method 201 or 201a) for the PM Method 5B or 5F required of Applicant in the EPA July, 2008 Consent Decree.

UDEQ-DAQ's decision to substitute PM-10 for the PM emission limitations required by the Consent Decree is particularly objectionable under the circumstance because neither Applicant nor UDEQ-DAQ have properly determined or evaluated PM in netting analysis required for this facility in violation of the requirement to evaluate PM as a new source review pollutant that must be shown not to exceed major source/major modification criteria

3.1.2 UDEQ-DAQ Failed to Provide a Best Available Control Technology Emission Limitation for PM, PM-10 or PM-2.5 to Control Emissions from FCC Unit 4

UDEQ-DAQ provided what it deemed to be a Best Available Control Technology PM-10 emission limitation for FCC Unit 25 at 0.3 lbs PM-10 per 1000 lbs of coke burn. However, FCC Unit #4 is subject to the same Best Available Control Technology requirement under state rules defining Best Available Control Technology in state

[9] EPA Consent Decree on Holly Refinery, July, 2008; paragraphs #33 & 34

regulation in the same manner as the federal BACT definition. UDEQ-DAQ's proposed BACT emission limitation for FCC Unit 4 is 0.5 lbs PM-10 per 1000 lbs of coke burn.

When UDEQ-DAQ rules define the stringency of the required Best Available Control Technology in the same manner as the federal BACT rule, a BACT determination made by UDEQ--DAQ under the same rule language as provided in federal statute and regulation cannot arrive at a result that would be different than the result that U.S. EPA would make as to BACT stringency. Moreover, UDEQ-DAQ's BACT requirement that applies to minor sources and modification is a requirement of the approved Utah State Implementation Plan. As a result, UDEQ-DAQ BACT decisions made pursuant to the approved SIP must necessarily reflect the required stringency of a federal PSD BACT determination even though a source is only minor.

In the present case, the FCC Unit #4 was physically changed by the removal of the CO Boiler #6 from the flue gas process train. Operation of the FCC Unit 4 catalytic regenerator unit without passing its exhaust through a CO Boiler is also a change in the method of operation of the unit. FCC Unit #4 was additionally subject to pollution control projects potentially affecting PM, PM-10 and PM-2.5 emission rates, that were physical changes or changes in the method of operation during the pendency of the present contemporaneous period under question as such contemporaneous changes are considered for netting purposes to take place at commencement of operation rather than at facility permitting. FCC Unit #4 should have been subject to the requirement to develop an emission limitation that reflected, at a minimum, Best Available Control Technology as defined by 40 C.F.R. §52.21(b)(12).

In addressing the FCC Unit 25 PM emission limitation of 0.3 lbs PM-10 per 1000 lbs of coke burn, UDEQ-DAQ was establishing a PM-10 BACT emission limitation with the meaning of both the state and federal definitions of Best Available Control Technology.

Since the BACT control emission limitation for PM-10 from the FCC Unit 25, such determination should also have been applied to the FCC Unit 4 PM-10 emissions as well since all indications are that the physical configuration of both units appear identical. Applicant has listed identical annual emissions of NOX, SO2 and CO from both of the catalytic regenerator exhausts for FCC Units 4 & 25. Commentors interpret this emissions information to indicate that both units have the same potential to emit for those pollutants and thus that the two units have the same physical process capacities. In this circumstance, the UDEQ-DAQ determination of a BACT emission limitation should also have been identical, and the fact that these two BACT determinations for PM-10 differ together with the FCC Unit 4 emission limitation being set at a level exceeding the determination on FCC Unit 25 demonstrates the UDEQ-DAQ's BACT determination for FCC Unit 4 is erroneous.

3.1.3 Publication of the UDEQ-DAQ Approval Order Setting NOX Emission Limitations for 4FCCU and 25FCCU Catalyst Regenerator Exhaust Must be Explained and Justified on the Record to Eliminate Error and Ambiguity

Commentors have been informed by UDEQ-DAQ staff that the publication of Condition II.B.2.b in the draft Approval Order published in 2012 with NOX limitations of 40 ppmvd per 365 day rolling average and 80 ppmvd per 7 day rolling average was erroneous as published,[10] and that the limits should have been indicated as 20 ppmvd per 365 day rolling average and 40 ppmvd per 7 day rolling average in a section with applicability to both FCC Unit 4 & 25 catalyst regenerator exhausts.

Notwithstanding this prior communication with UDEQ-DAQ staff before the prior public comment period, the agency has published again the same erroneous NOX emission limitations in the presently proposed in AO Condition II.B.2.b. Under paragraph 12 of the 2008 EPA Consent Decree, Applicant was supposed to have designed the NOX control system for the FCC Unit 4 catalytic regenerator to achieve 40 ppmvd on a 7 day rolling average and 20 ppmvd on a 365 day rolling average.

Commentors urge UDEQ-DAQ to publish this error correction formally and in writing so it is available to the public and so the 40 ppmvd/20 ppmvd NOX emission limitations are imposed on both catalytic regenerator exhausts for both FCC Units 4 and 25.

However, additional issues exist as to NOX emissions from these units.

If the facility is supposed to comply with a 20 ppmvd, 365 day rolling average emission limitation, then the Applicant's emission characterization and BACT determination is subject to question. Applicant's emission determination assumed a 40 ppmvd compliance level and Applicant's submittal was never updated to show an emission characterization at a level of 20 ppmvd compliance for NOX emissions from the two emission units.

The Approval Order should not be issued unless and until the Applicant intends to comply with the 20 ppmvd NOX 365 day rolling average emission limitation, as well as emission-unit-specific pound per hour NOX mass rate emission limitations.

3.1.4 UDEQ-DAQ has Omitted Oxygen Corrections for NOX and SO2 Emission Limitations that are Stack Flue Gas Concentration Limits

Condition II.B.2.b of the draft Approval Order fails to specify the correction to 0% oxygen that is required and assumed in the July, 2008 EPA Consent Decree.

[10] See Condition II.B.2.b of the draft Approval Order DAQE-IN101230041-12

The NOX and SO2 emission limitations are not properly stated or cannot be renedered unambiguously and with out interpretation only when the proper oxygen concentration is stated for such gas concentration emission limitation.

3.1.5 UDEQ-DAQ's Draft Approval Order Does Not Place Federally Enforceable Annual Throughput Limits on Operations of the FCC Unit 25 Process Unit

Condition II.B.1.e limits throughput in the FCCU Unit 4 process to 3,250,000 barrels per rolling 12-month period. No such federally enforceable limit on the FCCU Unit 25 has been provided. The present matter is one in which no emission-unit-specific time rate of mass emissions reflecting BACT have been imposed on an emission unit specific basis on FCC Units 4 and 25 in violation of state and federal BACT requirements.

The failure to incorporate a federally enforceable throughput limitation on FCC Unit 25 means there is no assurance this process unit will limit the potential to emit for criteria pollutants to mass emission values indicated in Applicant's emission characterization[11] and to the levels of emissions that were used in air quality modeling demonstrations.

3.1.6 No Portion of Applicant's NOI submittals in either 2012 or in 2013 Show or Explain How a 3,250,000 Barrel Per Rolling 12 Month Period Limitation on the Feedstock Rate to FCC Unit 4 as Contained in the UDEQ-DAQ's Draft Approval Order Actually Limits the Potential to Emit at Applicant's Facility to the Calculated Potential to Emit

After making a diligent search of all available file materials in the present matter, including those materials available from the UDEQ-DAQ web site and materials provided in a public records request, Commentors can find no complete justification, basis or explanation for the 3,250,000 barrel per rolling 12 month period feedstock limitation that explains or ensures that the FCC Unit 25 catalytic regenerator exhaust emissions will limit the annual potential to emit for the subject facility to the annual criteria pollutant emissions claimed in Applicant's emission characterization.

Commentors object to UDEQ-DAQ's proposed permit issuance decision under the circumstance of a technically incomplete application when applicant's emission calculation depends on assumptions stated to be "Engineering Calculation" with no submittal or showing of such calculations to justify allowing the maximum feedrate limitation shown in Condition II.B.1.e.

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[11] Applicant's emission characterization shows the following for FCC Unit 25:

NOX - 19.91 t/y; SO2 - 17.7 t/y; PM-10 - 8.15 t/y; CO - 154.85 t/y

Commentors first object to the failure of Applicant to certify the veracity of their NOI submittal on a UDEQ-DAQ Form 1 or other verification statement substitute. All failures to verify the veracity of Applicant's NOI submittals are also failures by UDEQ-DAQ because failure to verify NOI submittals violate EPA Title V program requirements for state air quality programs and undermine the Clean Air Act's requirements for Applicant's facility as a Title V major stationary source.

Commentors note UDEQ-DAQ's approval of a maximum feedstock rate of 3, 250,000 barrels per rolling 365 day period exceeds other stated limitations of the process in question. Condition II.A.2 indicates a process rate of 8,880 barrels per day of annual average capacity, but this condition does not have the effect of being a federally enforceable limitation on the physical FCC Unit 4 feedrate. At a process feedrate of 8,880 barrels per day, the annual feedrate would be 3, 241,200 barrels in a 365 day period, which is less than the rate allowed in Condition II.B.1.e.

Attachment #1 shows Applicant's emission calculations for FCC Unit 25 for criteria pollutants. The entire criteria pollutant calculation depends on two key Applicant provided factors:

> Maximum daily FCC flue gas flow rate: 23 mmscfd (Engineering Calculation)
>
> Maximum hourly FCC regenerator coke burn rate: 6200 lbs coke burn / hr (Engineering Calculation)

Applicant provided no "Engineering Calculation" at all to support either the maximum hourly coke burn rate or the daily FCC flue gas flow rate. Unsupported assumptions of this nature used for calculation of a source's potential to emit would be considered by most state air quality permit engineers to be a non-approvable, technically incomplete application. For this reason, UDEQ-DAQ should reject Applicant's submittal as non-approvable. First, the application is technically incomplete. Secondly, UDEQ-DAQ ought to consider the present permit decision on this specific matter in the manner of a fundamental programmatic re-evaluation of its present air quality permitting practices of providing no short term limitations on physical production and/or feedstock rates to limit PTE and no one hour SO2 emission limitations.

3.1.7 Neither Applicant Nor UDEQ-DAQ Have Properly Determined Maximum Potential to Emit for Short Term SO2 Emissions from the FCC Unit 25 Wet Scrubber Exhaust Vent Compliance Determination Point that are Associated with Sulfur Recovery Unit/SRU Incinerator Outages

All of the effort and workproduct presented by Applicant and UDEQ-DAQ focus on achieving a single gas-concentration-based level of SO2 control performance at both FCC Units 4 and 25 catalyst regenerator units. Applicant’s emission characterization for SO2 emissions indicates only compliance with a 25 ppmvd long term average and 50 ppmvd 7 day average emission.

While the permit contains ton per day and ton per year SO2 emission limitations for FCC Units 4 and 25, there is no 1 hour emission limitation or 24 hour emission limitation determined on a rolling hourly average basis for SO2 emissions from FCC Units 4 and 25.

The draft Approval Order Condition II.B.1.g indicates that the Sulfur Recovery Unit (Unit 17) process emissions will be routed to the FCC Unit 25 wet scrubber. Condition II.B.1.g neither mentions or requires that the SRU process unit emissions be sent to SRU gas incinerators to convert any residual hydrogen sulfide in Claus Plant effluent from the Sulfur Recovery Unit as discuss in the Section 2.2 narrative contained in Applicant's final Revised Notice of Intent.

The UDEQ-DAQ provision should not allow transfer of Claus Unit tailgas directly to the 25FCCU wet scrubber. That control unit is not a caustic scrubber which would be the required BACT-level control the hydrogen sulfide contained in the non-incinerated Claus Unit tail gas. Condition II.B.1.g must be amended to require that SRU 17 Claus Plant tail gas be sent to SRU incinerator units before being transferred to the wet scrubber installed on the 25FCCU Catalyst Regenerator Unit.

Similarly, Condition II.B.3.b should clearly be amended to require incinerator treatment before any Claus Unit tail gas is sent to the wet scrubbers.

In doing so, UDEQ-DAQ must ensure that Applicant submits an acceptable short term emission characterization of emissions from the wet scrubber during times of Claus Plant outages that cause high sulfur dioxide emissions from the SRU incinerator process. The reason for requiring short term emission limitations and emission characterizations is so that the UDEQ-DAQ Approval Order as issued achieves sulfur dioxide emission limitation at each refinery SO2 vent source sufficient to ensure compliance with the 1 hour SO2 National Ambient Air Quality Standard (NAAQS).

Failure to address, analyze and limit short term emissions of sulfur dioxide from all of Applicant's SO2-emitting process and emission units constitutes abdication by UDEQ-DAQ of required supervisory and controlling effect provisions programmatically necessary for achieving attainment or maintenance of the SO2 one hour NAAQS.

The nature of UDEQ-DAQ's failure to address short term SO2 emissions is by failing to address all SRU / tailgas incinerator process train outages, alternate operating scenarios, process gas dispositions and bypasses as well as any use of any refinery fuel gas or natural gas as 'assist' gas in the tailgas incinerator.

If a 10 long ton per day sulfur recovery unit with 3 Claus Units is operating at maximum capacity, each Claus Unit could receive 3.3 long tons per day of sulfur. If one such unit has an outage while all units are at maximum capacity and the other units are operating at full capacity, then the SRU incinerator could potentially receive untreated acid gas at a rate of 3.3 long tons of sulfur (unless bypasses of the Claus Units in the SRU are directed to one or both of the site process flares). This means 7392 lbs of sulfur directed to the incinerator at a rate of 308 lbs of sulfur per hour, or an incinerator SO2 emission source term of 616 lbs of sulfur dioxide entering the wet scrubber controlling 25FCCU. No assessment has been provided of this operational mode and the resulting final hourly sulfur dioxide emission rate at the compliance measurement point of the FCC Unit 25 vent stack under such claus unit outage conditions. Nor has any consideration been given to showing such a short term sulfur dioxide rate in air quality modeling demonstrations, which renders the conclusions of such modeling as not addressing actual high short term emission rates..

3.1.8 Oxygen Monitoring and Wet Scrubber Outlet Volumetric Flow Rate Determination Must be Required at FCC Units 4 & 25 Wet Scrubber Controlled Vent Stacks

Condition II.B.2.b.1 is not sufficient and vague and does not create an affirmative duty to install continuous oxygen monitoring on both FCC Unit 4 and 25 wet scrubber vent stacks.

Conditions II.B.2.a.1 and II.B.2.b.1 together require prescribe continuous emission monitoring system operational requirements for for FCC Units 4 and 25 wet scrubber discharge vents. These AO provisions contain no clear requirement that clearly and unambiguously requires continuous oxygen monitoring and continuous monitoring of the vent outlet volumetric discharge rate through continuous gas flow velocity monitoring in the outlet vent.

The Approval Order should not be granted without specific provisions requiring continuous oxygen monitoring and continuous gas exit velocity monitoring in an appropriate outlet vent location just prior to atmospheric discharge.

Continuous oxygen monitoring is required for proper emission limitation compliance and enforcement purposes.

Emission data from the continuous emission monitoring systems at the FCC Units 4 and 25 process units are used as a basis for determining Applicant's compliance with stack vent gas concentration emission limitations. Because a continuous emission analyzer generates gas concentration emissions information, such gas concentration data must be used with a volumetric flow determination in order to determine the rate of mass emissions from the sources in question.

In the present matter, Applicant should be required to install, operate, maintain and calibrate (under a quarterly system of recordkeeping and compliance reporting) a continuous exit gas flow velocity monitor on both FCCU scrubber stacks and to use such data for continuous volumetric flow determination for purposes of accurate determination of the mass emission rates from the subject facility. The data system for handling CEM and flow data must integrate these date in real time for calculation, recordkeeping and reporting purposes.

3.1.9 The UDEQ-DAQ Approval Order Fails to Provide Suffient Monitoring of FCC Unit 4 & 25 Wet Scrubber Operation Sufficient for the Applicant to be Able to Assure Compliance with PM-10 Emission Limitations

Since Applicant has already sought an alternate compliance monitoring on visible emissions limitations under the July 2008 Consent Decree, such parameter monitoring should be a required part of the Approval Order. For wet scrubber-controlled units, the FCC Unit 4 & 25 catalyst regenerator process units, Applicant should be required to install, operate, maintain and calibrate continuous parameter monitoring for pertinent FCCU process and wet scrubber operational parameters, including rate of coke burn, combustion oxygen, regenerator temperature, scrubber flow recirculation rate, scrubber liquor pH, scrubber supply water flow rate, scrubber pressure drop and other pertinent parameters.

The Approval Order should require that the facility maintain all parameters at rates which have been demonstrated in a recent stack test to reflect compliant process and wet scrubber control unit operating conditions in compliance with stack test verified PM emissions less than any applicable PM emission limitations.

Finally, a provision must be included which specifies recordkeeping and reporting requirements on operation of all continuous parameter monitoring, including testing for accuracy and calibration in actual operation.

3.1.10 UDEQ-DAQ Eliminated a the Previously Establish PM Limits for FCC Unit 4 Without Replacing Such a Limit with a Revised BACT Determination

Applicant was previously subjected to PM emissions limitations of 0.09 tons per day and 32 tons per year at the discharge of the 4V82 FCC wet scrubber.

If such limitation was incorporated into the Utah SIP, then elimination of such a requirement constitutes an objectionable relaxation of the Utah State Implementation Plan for PM-10.

UDEQ-DAQ should require PM-10 and PM 2.5 time rate of mass emission limitations at a minimum which reflect the the UDEQ-DAQ BACT determination as applied at each process and emission unit.

3.1.11 Applicant Has Not Demonstrated that the 15% Opacity Limit for 25FCCU Constitutes a BACT Visible Emission Limitation

Since the FCC Unit 25 is being permitted as a PSD major stationary source, discharges from all new and modified process units [including FCC Units 25] are subject to a requirement for a BACT determination of visible emissions under 40 C.F.R. §52.21(b)(12) which includes visible emission standards under the definition of BACT.

No part of Applicant's final Revised Notice of Intent contains a BACT determination for visible emissions from this source. Applicant should be able to comply with less than a 20% opacity limitation on these newly scrubber controlled units as determined by an EPA Method 9 inspection. However the present condition II.B.1.c allows 20% opacity from the FCC wet scrubber controlled units without any basis or justification in a visible emission BACT determination analysis.

3.1.12 Applicant Must Address Condensible Emissions from FCC Unit 4 & 25 Catalytic Regenerator Wet Scrubber Controlled Units

Emission estimates for the wet scrubber controlled FCCU units appear to be filterable-only estimates and Applicant must be required to fully characterize both filterable and condensable emissions for these units. Applicant must provide total filterable plus condensible PM, PM-10 and PM-2.5 emissions for both FCCU units at the refinery for purposes of Applicant's analysis for emission increases and net emission increase determinations for purposes of 40 C.F.R. §52.21(a)(2)(iv)(a) analysis.

3.1.13 UDEQ-DAQ Must Regulate the FCC 34" Flue Gas Bypass

The Draft Approval Order contains an authorization of a vent discharge in the form of the "FCC 34" Flue Gas Bypass." As proposed, there are no provisions of the Draft Approval Order which regulate, monitor or limit emissions from this vent.

Commentors presume that this emission point, if opened, would allow uncontrolled and untreated 4FCCU Catalyst Regenerator process gas to discharge the unit directly to the atmosphere.

UDEQ-DAQ must regulate this discharge point by subjecting it to emission limitations and/or work practice requirements, monitoring, recordkeeping and reporting on any emissions occurring from such FCC Unit 4 scrubber bypass venting.

3.2 Flaring, Flare Gas Collection and Refinery Pressure Relief System

3.2.1 Nothing Provided by the Applicant's Final Revised Notice of Intent Justifies the Claimed 98% Control Efficiency Claimed for VOC, HAP and CO Destruction Efficiency from Applicant's Open Air Flares

All of Applicant's VOC;, HAP and CO emission determinations from the two site flares depend on an assumed 98% control destruction efficiency claimed in Applicant's flare emission calculation sheets.

Applicant has not provided any information to justify the claimed 98% flare control efficiency. Applicant has not provided detailed physical information about its flares. Applicant has not considered the adverse effects of high cross winds on flare operation and destruction efficiency because of reduced combustion temperatures in open air flare operation.

Applicant's has not shown how the flare technology they plan for the modified flare will support the 98% control efficiency claimed. Applicant has not shown how any such destruction efficiency shall be assurred on a continuous basis.

3.2.2 Applicant Failed to Address All Parts of the Existing and Proposed Flare Gas System and Failed to Carry Out a "Top Down" Best Available Control Technology Analysis

Both emissions determination and Best Available Control Technology review require a detailed exposition of the entire flare gas collection system and not just mention of the two existing flares. Design information on the flares as presently in use and as they are intended to be modified for future use must be provided for proper emission characterization and BACT review of the entire flare gas system.

A proper review of the flare system would include details on the gas collection system used to collect process gas intended for flare disposal, what atmospheric discharge pressure operated relief valves are provided in each existing and new/modified process at the refinery site, what manifold system is in place to collect pressure operated relief valve emissions that are not directed to atmospheric discharge but into the flare gas collection system, issues of management and disposition of acid gas vs. hydrocarbon gas for flare operation and how each type of gas is transported to each of the site flares, the use of knock-out pots to remove entrained liquid aerosals from collected flare gas, the presence of gas metering on gas volumes directed to the flares, the type of assisted or nonassisted flares to be used, the method and gas consumption from flare pilot flames (or the use of igniters) and the presence of a flame detection system that instrumented to the refinery operations control room to ensure the flare remains lit at all times. All such information is needed for a proper evaluation of emissions from such flares and such information should be present for a BACT determination affecting flare emission units.

However, a BACT determination must also necessarily include consideration of flare gas and pressure relief system alternate flare/gas collection/pressure relief system designs, such as flare gas recovery systems, use of refractory lined "tip incinerators" in which the combustion zone is shielded from the wind, use of ground flares with elevated, refractory-lined stacks and dedicated waste gas incinerators with emission controls and/or elevated stacks. Applicant failed to include any such alternative technical options in the claimed "top down" BACT determination submitted on two pages of the NOI, with the exception of the flare gas recovery system which Applicant rejected.

UDEQ-DAQ should reject Applicant's BACT determination because it failed to carry out a proper narrative and description of both existing flare and pressure relief system components and it failed to properly consider flare system technology alternatives as required in BACT determination and in the "top down" BACT determination process.

3.2.3 Applicant's Cannot Dismiss Flare Gas Recovery Systems as a BACT Requirement Without Considering Prevailing Industry Practice in Favor of Such Systems at Larger Refineries

Applicant's BACT determination for flares dismissed flare gas recovery systems as being uneconomic because of high costs for control for CO, NOX and VOC. The Applicant performed a greenhouse gas cost of control determination claiming $72.45 cost per ton of CO2e removed and further claimed this cost to be uneconomic by exceeding Applicant's threshold of $8/ton CO2e.

Commentors object to the 10 year economic life range on the flare gas compressor control cost evaluation as being too short and not typical of the expected life of compressor units. Commentors object to the claimed 13.59% capitol recovery factor at high and unrealistic.

In considering greenhouse gas BACT, a decision should properly prefer recovery of flare gas for beneficial use elsewhere in heaters and boilers in the refinery over simple flaring as the matter relates to BACT benefits of flare gas recovery systems.

Applicant's BACT cost of control review review addressing the matter of flare gas recovery compressors also claimed zero SO2 emission reduced and no cost analysis was done.[12] Applicant repeated their zero SO2 emission reduction achieved from a flare gas compressor claim in a later 2013 submittal; see Attachment #2. However, Applicant also stated that sulfur dioxide emissions from flares were 120 tons of sulfur dioxide per flare per year, so a claim of only 0.1 ton for control isn't credible. See Attachment #3 for flare SO2 information due to upsets.

Flare gas recovery systems have become common in the petroleum refining industry at larger facilities. In such circumstances, Applicant's holding that such units are non-economic cannot be sustained for purposes of BACT review for such a common industry practice.

3.2.4 Applicant's Description of South Flare Gas Flow Conflicts with NSPS Subpart Ja

Applicant states:

> "The average non-upset throughput to the south flare is estimated to be 17,000 standard cubic feet for hour (scf/h) and was based on 2011 flow monitoring data."[13]

Applicant repeated the 17,000 scf/hr flare gas volume claim in the most recent and final emission calculations submitted by the Applicant; see Attachment #4.

Provisions in NSPS Subpart Ja to which Applicant is subject provide:

> "3) Except as provided in paragraphs (h) and (i) of this section, the owner or operator of an affected flare shall not allow flow to each affected flare during normal operations of more than 7,080 standard cubic meters per day (m3/day) (250,000 standard cubic feet per day (scfd)) on a 30-day rolling average. The owner or operator of a newly constructed or reconstructed flare shall comply with the emission limit in this paragraph by no later than the date that flare becomes an affected flare subject to this subpart. The owner or operator of a modified flare shall comply with the emission limit in this paragraph by no later than 1 year after that flare becomes an affected flare subject to this subpart."[14]

A rate of 17,000 scf/hr is equal to 408,000 scf per day which exceeds the 250,000 scf per day maximum emission flow requirement contained in NSPS Subpart Ja. Such a flare

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[12] Section 5.9.1.4 of Applicant's final Revised NOI, July 2012, p. 5-73

[13] Section 3.4.4 "Flare" section, p. 3-24 of Applicant's final Revised NOI, July, 2012

[14] 40 C.F.R. §60.102a(g)(3)

and associated gas collection system would not comply with NSPS Subpart Ja and cannot be approved as proposed.

Applicant's typical flaring of non-upset gas exceeds the limitation contained in the rule with a 250,000 scf/day limitation for Subpart Ja-affected flare units. Nothing in Applicant's final Revised NOI addresses Applicant's defficient flaring system for excessive flaring of usual and ordinary emissions.

3.2.5 Flare Gas Flow Metering Requirement

Condition II.B.11.d addresses "flow meters" and "gas combustion monitors" on the South Flare gas line, but no requirement of the permit addresses similar functions and needs on the north flare portion of the system.

3.2.6 Flare Opacity Limitation is Not a BACT Limitation

Condition II.B.1.c of the draft Approval Order indicates a 20% opacity limit for all flares. While such an opacity limit may comply with Utah State Implementation Requirements on visible emissions, such a 20% opacity requirement has not been shown or determined in a Best Available Control Technology finding to be a BACT-related visible emission limitation that is required under

The proper BACT visible emission limitation must be established for the two flares based on a demonstration showing compliance with 40 C.F.R. §52.21(b)(12).

3.2.7 UDEQ-DAQ Must Make a Clear Finding that the Proposed Refinery Modification, Including all New and Modified Equipment, Are Subject to NSPS Subpart Ja

UDEQ-DAQ should clarify that all new and modified equipment that is part of the Approval Order must be considered as subject to NSPS Subpart Ja.

In particular, UDEQ-DAQ should clarify that both site flares are subject to Subpart Ja requirements as a result of flare header and piping changes associated with the expansion and addition of new process units and extension of flare manifold and header systems. On September 12, 2012, EPA published a lift of a previous stay of certain provisions of

EPA's NSPS Subpart A and Ja rules.[15] The rule on which was the stay was lifted require that new piping systems installed to accomodate expansions as Applicant has undertaken cause entire flare systems to become subject to requirements for Subpart Ja flares under 40 C.F.R. §60.100a(c).

UDEQ-DAQ should include a specific flare section in the permit that includes all flare emission limitations that are either numerical limits or work practice requirements, including design requirements. Such a section must have specific sections addressing flare monitoring and flare pilot/ignition operation, flare steam assist, and other requirements for the design, monitoring, recordkeeping and reporting of flare emissions. The section should also address acid gas flaring and hydrocarbon flaring considered to be in violation because of failure to maintain good engineering practice process operations.

3.2.8 SRU Incinerator

UDEQ-DAQ should clarify whether assist gas in the form of natural gas or refinery fuel gas can physically be burned in the SRU incinerator.

If refinery fuel gas can be burned in the SRU incinerator, the Applicant must address the amount and the emissions associated with any use of assist gas int he SRU Incinerator.

UDEQ-DAQ must require that the SRU incinerator not be considered a means of disposal for excesses of available refinery fuel gas. Further, use of the SRU incinerator in that manner must be identified as a form of process refinery gas flaring done outside of the existing flaring system of elevated flares. Applicant must not be permitted to 'hide' hydrocarbon flaring by disguising it as an incinerator operation.

UDEQ-DAQ should require a disclosure that the reduction in use of refinery fuel gas associated with the closing of the 4 compressor drivers cannot become the reasons for hydrocarbon flaring in the future of the facility.

3.3 Controlled Refinery Process Wastewater Sewers

UDEQ-DAQ should clarify the status of the entire refinery process wastewater sewer system, both currently and in the future final configuration of the proposed facility. This clarification should show and determine which parts of the refinery sewer system become subject to NSPS Subpart QQQ because of refinery expansion and new system connection.

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[15] 77 Fed. Reg. 56422, with specific provision at 56464

3.4 Neither the UDEQ-DAQ Draft Approval Order, Nor the Applicant's Final Revised Notice of Intent Contain Any Limitation on Cooling Tower Water Total Dissolved Solids

While Applicant has submitted information about the drift elimination rate for the cooling tower equipment, the mere specification of the design basis for drift elimination is not sufficient to limit the potential to emit of cooling tower emission units.

UDEQ-DAQ should amend the proposed permit to specify a maximum limit on allowable total dissolved solids that can recirculated in the site cooling tower systems.

The PM-10 potential to emit of a cooling tower cannot be limited unless there is a physical limitation placed on the maximum cooling tower recirculation total dissolved solids allowable by permit in the system.

3.5 UDEQ-DAQ's Draft Approval Order Fails to Incorporate Applicant's VOC BACT Determination and Fails to Address EPA Consent Decree Requirements for LDAR Programs at Applicant's Facility

Applicant states that it was including lower leak definitions in its fugitive emissions control program of 2000 ppm for pumps and 500ppm for valves. However, UDEQ-DAQ never incorporated such requirements in the Draft Approval Order, so there is no clearly required federally enforceable provision that requires Applicant to do what Applicant claims as VOC BACT control in leak detection and repair programs.

Applicant's BACT review of control alternatives for VOC fugitives fails to consider usage and work practices involving remote sensing and determination of refinery component leaks through infrared backscatter techniques and other methods of remote visualization.

In addition, no provision of the permit incorporates July, 2008 EPA Consent Decree requirements for LDAR improvements made under that decree into federally enforceable requirements that are Approval Order conditions. UDEQ-DAQ's air quality programmatic failure to require specific provisions Approval Order conditions recognizing facility fugitive VOC and HAP emissions and recognizing that AO conditions must necessarily be included to set emission limitations for fugitive emissions that are BACT limits.

3.6 Heaters, Boilers and Refinery Fuel Gas System

3.6.1 Condition II.B.1.d Should Require Continuous Total Sulfur Analyzer

As written, Condition II.B.1.d requires monitoring of hydrogen sulfide in refinery fuel gas as the only means of determining sulfur dioxide emissions from the facility. However, moitoring hydrogen sulfide only in refinery fuel gas means that sulfur dioxide emissions from burning such gases will be significantly understated in typical refinery use in the monitoring done with only hydrogen sulfide being detected in fuel gas to be burned. Such a circumstance is unacceptable and will render the monitoring provided to be inadequate to accurately determine the actual rate of sulfur dioxide emissions during refinery operations.

Refinery fuel gas will contain sulfur compounds that include methyl mercaptan, dimethyl sulfide, ethyl mercaptan, carbonyl sulfide, carbon disulfide and potentially other sulfur compounds.

The refinery fuel system must be designed to incorporate a total sulfur continuous gas analyzer instead of simply total hydrogen sulfide continuous detection.

Applicant must be required to submit plans and specifications for the refinery fuel gas system that shows the gas collection network from process overheads throughout the refinery, and the locations where continuous analyzers should be placed to ensure that 100% of the refinery fuel gas flows sent to boilers and heaters is monitored for gas flow and total sulfur.

3.6.2 Applicant's Boiler and Heater SO2 Short Term Emission Characterization is Erroneous

Applicant has characterized SO2 emissions from refinery site boilers and heaters using SO2 emissions based on refinery fuel gas at 60 ppmv on a annual average for both short term and long term emissions. However, Applicant states that the 3 hour hydrogen sulfide shall not be greater than 162 ppmv. This means that Applicant's maximum 1 hour sulfur dioxide emission characterizations are erroneous and understated since a short term average of such emissions from burning refinery fuel gas will physically exceed the 1 hour emission rates calculated on the basis of 60 ppmv.

One hour maximum potential to emit determinations for sulfur dioxide must be based on the maximum short term refinery fuel gas concentrations and not annual average concentrations. As a result, Applicant's maximum short term emission numbers for 1 hour averages from heaters and boilers should be increased by a factor of 2.6, and such corrected short term maximum sulfur dioxide emissions should be reflects in air quality modeling and, in particular, for modeling designed to evaluate compliance with EPA's short term 1 hour SO2 National Ambient Air Quality Standards (NAAQS).

3.6.3 UDEQ-DAQ Must Address Heater/Boiler NOX CEM Requirement

UDEQ-DAQ must provide appropriate continuous emission and parameter monitoring for operation of heaters and boilers and must address NOX monitoring of such sources.

All units with SCR should be required to have NOX continuous emission monitors on each process unit. Commentors suggest NOX CEMs for all boilers and heaters exceeding 50 mmbtu/hr.

Such NOX CEM requirements should be enacted in the permit with addtional requirements for performance specifications, reporting and recordkeeping.

4 Air Quality Impact Review Section

4.1 Applicant's Sulfur Dioxide Air Quality Modeling Prediction Understated the Short Term Sulfur Dioxide Ambient Air Quality Impact Because of the Understated Modeled Emission Rates for the Two Site Process Flares

Air quality modeling exercises and demonstrations carried out in the State of Utah must follow R307-405-13 which binds the Utah State Implementation Plan and New Source Review process to 40 C.F. R. §52.21(l), which in turn binds all such modeling demonstrations, review and analysis to 40 C.F.R. Part 52, Appendix W.

40 C.F.R. Part 52, Appendix W review of source data recommendations states:

> "a. For point source applications **the load or operating condition that causes maximum ground-level concentrations should be established**. As a minimum, the source should be modeled using the design capacity (100 percent load). **If a source operates at greater than design capacity for periods that could result in violations of the standards or PSD increments, this load) a should be modeled.**"[16] (emphasis added)

This language must be read in the context of the Applicant's obligations to properly consider the maximum potential short term sulfur dioxide emission rates from each of the two refinery process flares. Flare operation cannot be considered as a refinery malfunction condition that would not be modified as use of the flare system by the refinery operator is not a malfunction in the operation of a flare emission unit. In

[16] 40 C.F.R. Part 51, Appendix W, Section 8.1.2(a), in part.

addition, past Approval Order conditions stating that process flare emissions at the Applicant's refinery are sources that "....shall not be regulated for SO2 emissions, nor shall they be included in the emission limitation totals herein"[17] cannot be deemed to have a determinant effect on Applicant's obligations to properly model the facility's emissions under Appendix W or to consider all flare operation under the rubric of refinery malfunction.

The public rightly expects a properly determined air quality impact review of the maximum sulfur dioxide emission rates that may occur from operation of the two remaining flares at the refinery facility.

However, Applicant's sulfur dioxide air quality modeling improperly understates the ambient impact of refinery site process flares on the predicted ambient, ground-level sulfur dioxide ambient concentrations because the short term emission rates for the two process flares are not properly characterized.

Applicant's Table 6-4 shows a sulfur dioxide emission rate of 0.0030 grams per second for each of the two site flares. That rate is equivalent to sulfur dioxide emissions at a constant rate of 0.1 tons of sulfur dioxide per year. Applicant also showed a "SO2 emission factor for industrial flares: 0.0238 lb/hr" in Applicant's Appendix for emission calculations and potential to emit estimates. A rate of 0.0238 lb/hr is also equivalent to a constant emission at a rate of 0.1 tons per year.

However, Applicant admits as a "proposed flare emissions from upsets" characterization emissions of 120 tons per year per flare.[18] No emission calculations were provided in Applicant's final Revised Notice of Intent Appendixes that justifies the 120 tons of sulfur dioxide per flare per year emission level. Applicant is under an obligation to properly premise air quality modeling demonstrations attempting to show environmental acceptability for community exposures to sulfur dioxide ambient air quality impacts and compliance with short term National Ambient Air Quality Standards for Sulfur Dioxide. The "PTE Emission Rates" provided in Table 6-4 must be properly determine pursuant to the Appendix W-required determination factor addressing what maximum sulfur dioxide emission rate should be modeled to determine the maximum sulfur dioxide ambient impact from the two site process flares.

Applicant's specification of a 0.0030 gram per second SO2 emission rate for each of the site process flares must be considered erroneous and understated. A modeling demonstration using such an emission rate for the flare emissions cannot properly show that the facility will not jeopardized maintenance of short term National Ambient Air Quality Standards for Sulfur Dioxide.

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[17] Condition II.B.4.c of Approval Order DAQE-AN0101230038-10

[18] See Section 3.6 of Applicant's final Revised Notice of Intent, p. 3-37

The Approval Order should not be approved without a revised emission characterization and subsequent revised modeling demonstration which addresses the maximum sulfur dioxide emissions expected from flare operation and the effect of such operation on the 1 hr, 3 hr and 24 hour National Ambient Air Quality Standards for Sulfur Dioxide.

5 Miscellaneous Comments Addressing Typographical Errors, Format and Citation Errors

UDEQ-DAQ Intent to Approve:

The CFR citation at paragraph 1.3 is not complete and/or missing.

Applicant July, 2012 NOI:

The Applicant July, 2012 NOI submittal in Section 3 extensively used the word "credible" when the material should instead have been using the word "creditable." Because this is a non-significant error, Applicant must be required to correct these errors in writing and on the record of the proceeding.

-end-

Attachment #1

FCCU #2 Scrubber - New
Holly Marketing & Refining Company

Equations Used:

$PM_{10}/PM_{2.5}$ = 6200 lb coke burn/hr /1000 * Consent Decree FCCU PM limit*operating hours per year

SO_2 = Maximum daily FCC flue gas flow rate * Consent Decree FCCU SOx limit *(1/379.5 scf*MW SOx)*Operating hours per year

NO_x = Maximum daily FCC flue gas flow rate * Consent Decree FCCU NOx limit *(1/379.5 scf*MW NOx)*Operating hours per year

CO = Maximum daily FCC flue gas flow rate * Consent Decree FCCU CO limit *(1/379.5 scf*MW CO)*Operating hours per year

		Emissions	
Pollutant	lb/hr	(lb/yr)	(tn/yr)
NO_x	4.545	39818.18	19.91
SO2	4.040	35393.94	17.70
VOC	Neg.	Neg.	Neg.
PM_{10}	1.9	16293.6	8.15
$PM_{2.5}$	1.86	16293.6	8.15
CO	35.354	309697	154.85

Assumptions:

Emissions controlled through wet gas scrubber

NOx from CD controlled fluid catalytic cracking units:	40	Holly Consent Decree FCCU NOx final limits (ppmvd 0% O2 365 day average)
SO2 from CD controlled fluid catalytic cracking units:	25	Holly Consent Decree FCCU SOx final limits (ppmvd 0% O2 365 day average)
PM10 from CD controlled fluid catalytic cracking units:	0.3	Ja
PM2.5 from CD controlled fluid catalytic cracking units:	0.3	All PM10 assumed to be PM2.5 (lb/1000 lb coke burn)
CO Emission Limit for FCCU:	500	ppm (1 hr average 0% O2)
VOC from controlled fluid catalytic cracking units:	Neg	AP-42 Emission Factors from Table 5.1-1 (lb/10^3 bbl fresh feed) [TOC]
Plant Wide Annual Operating Time:	8760	hr
Conversion from scf to lb mol:	379.5	scf -> lb mol
Maximum daily FCC flue gas flow rate:	23	mmscfd (Engineering Calculation)
Maximum hourly FCC regenerator coke burn rate:	6200	lbs coke burn / hr (Engineering Calculation)
Molecular Weight of CO:	28	lb/lb-mol
Molecular Weight of NOx:	45	lb/lb-mol
Molecular Weight of SOx:	64	lb/lb-mol

Attachment #2

10	Economic life (yrs)
6.00%	Depreciation range (%)
13.59%	Capital Recovery Factor
$ 8,053,500.00	Total turnkey costs ($) - total costs (capital) less labor and maintance costs
$ 1,094,212.60	Capital Recover
$ 567,420.00	Total Direct Costs
$ 128,856.00	Overhead ($/yr)
$ 322,140.00	Taxes, Insurance, and Admin ($/yr)
$ 1,094,212.60	Capital Recovery
$ 1,545,208.60	Total Indirect Costs ($/yr)
$ 2,112,628.60	Total Annual Costs
$ 1,300,000.00	Recovery Benfit
$ 812,628.60	Total Costs
5.76	NOx Removal (tpy)
$ 141,081.35	Cost per ton NOx removal
31.36	CO Removal (tpy)
$ 25,912.90	Cost per ton CO removal
0	PM10 Removal (tpy)
#DIV/0!	Cost per ton PM10 removal
0	PM2.5 Removal (tpy)
#DIV/0!	Cost per ton PM2.5 removal
5.37	VOC Removal (tpy)
$ 151,327.49	Cost per ton VOC removal
0	SOx Removal (tpy)
#DIV/0!	Cost per ton SOx removal
10,545	CO2 Removal (short tons per year)
32	CH4 Removal (short tons per year
-	N2O Removal (short tons per year)
11,217	CO2e removal (short tons per year)
$ 72.45	Cost per ton CO2e removal

Notes:

1)Cost effectiveness of CO2e removal: based on tailoring rule which considers 100,000 tpy CO2e equal to 100 tpy of a criteria pollutant (100/100,000=.001), then if th threshold for a criteria pollutant is $8000, then 8000 * 0.001 = $8/ton would be the threshold for GHG's

Attachment #3

3.6 Flaring Emissions Due to Upsets

Flaring emissions from upset conditions were calculated based on the average emissions calculated for flaring events from 2005 through 2008 from the existing north and south flares. Three standards deviations were applied to the average emission estimates so that a conservative emissions estimate could be obtained. Proposed flare emissions from upsets for the north and south flare are as follows:

- SO_2 – 120 TPY per flare
- NO_x – 4 TPY per flare
- VOC – 8 TPY per flare
- CO – 21 TPY per flare

3.7 Potential to Emit Emissions for Entire Refinery

Based on the above calculation methodologies, PTE emissions for the entire refinery which includes existing operations and proposed changes were determined. These PTE emissions are presented in Table 3-14.

Table 3-14

Potential to Emit Emissions for

Holly Refining & Marketing Company Woods Cross Refinery

Equipment	PM_{10} (TPY)	$PM_{2.5}$ (TPY)	SO_2 (TPY)	NO_x (TPY)	VOC (TPY)	CO (TPY)
All combustion sources (SIP sources)	84.4	84.4	109.5	364.9	42.7	912.2
All other sources (Non-SIP sources)	101.7	1.9	4.5	12.9	207.9	67.1
All Sources	186.1	86.3	114.1[1]	377.7	2621.7[2]	979.3

[1] Value does not include flaring upset emissions.
[2] Total includes fugitives including emissions from tank cleaning.

Attachment #4

Flare Emissions (South Flare)
Holly Marketing & Refining Company

References:	AP-42 Section 13.5 Industrial Flares
	California Air Resources Board
	EPA's Technology Transfer Network
	API Compendium of Greenhouse Gas Emission Methodologies for the Oil and Gas Industry

$E_{(lb/hr)}$ = flare gas vol (scf/hr) * HHV (Btu/scf) * (1 MMBtu/1000000 Btu) * EF (lb/MMBtu)

flare gas vol	17,000.0	scf/hr
HHV	1150	Btu/scf
$EF_{(CO)}$ =	0.37	lb/MMBtu
$EF_{(NOx)}$ =	0.068	lb/MMBtu
$EF_{(VOC)}$ =	5.6	lb/MMcf
$EF_{(benzene)}$ =	0.159	lb/MMcf
$EF_{(formaldehyde)}$ =	1.169	lb/MMcf
$EF_{(naphthalene)}$ =	0.011	lb/MMcf
$EF_{(acetaldehyde)}$ =	0.043	lb/MMcf
$EF_{(acrolein)}$ =	0.01	lb/MMcf
$EF_{(propylene)}$ =	2.44	lb/MMcf
$EF_{(toluene)}$ =	0.058	lb/MMcf
$EF_{(xylenes)}$ =	0.029	lb/MMcf
$EF_{(ethylbenzene)}$ =	1.44	lb/MMcf
$EF_{(hexane)}$ =	0.029	lb/MMcf
$EF_{(SO2)}$ =	0.024	lb/hr

Pollutant	Emissions (lb/hr)	Emissions (TPY)	Baseline (TPY)	Net Emissions (TPY)	
CO	7.2335	31.68	0.00	31.68	Baseline 2010-2011
NOx	1.3294	5.82	-0.925	4.90	Baseline 2004-2005
VOC	9.52E-02	0.42	-4.29	-3.87	Baseline 2007-2008
Benzene	2.70E-03	1.18E-02			
Formaldehyde	1.99E-02	8.70E-02			
Naphthalene	1.87E-04	8.19E-04			
Acetaldehyde	7.31E-04	3.20E-03			
Acrolein	1.70E-04	7.45E-04			
Propylene	4.15E-02	1.82E-01			
Toluene	9.86E-04	4.32E-03			
Xylene	4.93E-04	2.16E-03			
Ethylbenzene	2.45E-02	1.07E-01			
Hexane	4.93E-04	2.16E-03			
Total HAPS		4.01E-01			
SO_2	0.024	0.1042	-4.42	-4.32	Baseline 2005-2006

Assumptions:
Flare efficiency - 98%
Average methane concentration of total HC is 55% per AP-42
Questar - 1 grain S/100 scf
HAPS speciation from CARB
VOC emission factor from webfire database

Attachment #5

Boiler #11 - New
Holly Marketing & Refining Company

Pollutant	Equipment Rating (MMBtu/hr)	Emission Factor (lb/mmscf)	Conversion lb/mmscf to lb/MMBtu	(lb/hr)	Emissions (lb/yr)	(tn/yr)
NOx	89.3		0.02	1.786	15645.36	7.82
SO2	89.3	10.1281	1020	0.886	7768.05	3.88
VOC	89.3	5.5	1020	0.482	4218.11	2.11
PM_{10}	89.3	7.6	1020	0.665	5828.66	2.91
$PM_{2.5}$	89.3	7.6	1020	0.665	5828.66	2.91
CO	89.3	84	1020	7.354	64422.07	32.21
lead	89.3	0.0005	1020	4.38E-05	0.38	1.92E-04
benzene	89.3	2.10E-03	1020	1.84E-04	1.61E+00	8.05E-04
formaldehyde	89.3	7.50E-02	1020	6.57E-03	5.75E+01	2.88E-02
hexane	89.3	1.8	1020	1.58E-01	1.38E+03	6.90E-01
naphthalene	89.3	6.10E-04	1020	5.34E-05	4.68E-01	2.34E-04
toluene	89.3	3.40E-03	1020	2.98E-04	2.61E+00	1.30E-03
arsenic	89.3	2.00E-04	1020	1.75E-05	1.53E-01	7.67E-05
beryllium	89.3	1.20E-05	1020	1.05E-06	9.20E-03	4.60E-06
cadmium	89.3	1.10E-03	1020	9.63E-05	8.44E-01	4.22E-04
chromium	89.3	1.40E-03	1020	1.23E-04	1.07E+00	5.37E-04
cobalt	89.3	8.40E-05	1020	7.35E-06	6.44E-02	3.22E-05
manganese	89.3	3.80E-04	1020	3.33E-05	2.91E-01	1.46E-04
mercury	89.3	2.60E-04	1020	2.28E-05	1.99E-01	9.97E-05
nickel	89.3	2.10E-03	1020	1.84E-04	1.61E+00	8.05E-04
selenium	89.3	2.40E-05	1020	2.10E-06	1.84E-02	9.20E-06
Total HAPS						0.72

Assumptions
Selective Catalytic Reduction for emissions control
Emission estimates based on AP-42, Section 1.4 Natural Gas Combustion
SO_2 emissions based on H_2S content of 60 ppmv

Attachment #6

3.6 Flaring Emissions Due to Upsets

Flaring emissions from upset conditions were calculated based on the average emissions calculated for flaring events from 2005 through 2008 from the existing north and south flares. Three standards deviations were applied to the average emission estimates so that a conservative emissions estimate could be obtained. Proposed flare emissions from upsets for the north and south flare are as follows:

- SO_2 – 120 TPY per flare
- NO_x – 4 TPY per flare
- VOC – 8 TPY per flare
- CO – 21 TPY per flare

3.7 Potential to Emit Emissions for Entire Refinery

Based on the above calculation methodologies, PTE emissions for the entire refinery which includes existing operations and proposed changes were determined. These PTE emissions are presented in Table 3-14.

Table 3-14
Potential to Emit Emissions for
Holly Refining & Marketing Company Woods Cross Refinery

Equipment	PM_{10} (TPY)	$PM_{2.5}$ (TPY)	SO_2 (TPY)	NO_x (TPY)	VOC (TPY)	CO (TPY)
All combustion sources (SIP sources)	84.4	84.4	109.5	364.9	42.7	912.2
All other sources (Non-SIP sources)	101.7	1.9	4.5	12.9	207.9	67.1
All Sources	186.1	86.3	114.1[1]	377.7	2621.7[2]	979.3

[1] Value does not include flaring upset emissions.
[2] Total includes fugitives including emissions from tank cleaning.

Attachment #7

Site and Company/Owner Name: k. Holly Corp: HRMC and HEP Woods Cross Operations
Site ID: 10123

The Holly Refining & Marketing Company – Woods Cross Refinery is located in West Bountiful, Davis County.

Description of Facility:
The Woods Cross Refinery processes regional crude oils and produces gasoline, diesel, jet fuel, fuel oil, and asphalt. Process include crude distillation, catalytic cracking, catalytic reforming, alkylation, distillate hydrotreating, solvent deasphalting, naphtha hydrodesulfurization, gas processing and treatment, sufur recovery, gas oil hydrocracking, and sour water and ammonia stripping. On site utilities include steam production, and water treatment and cooling. The facility can currently process up to 31,000 barrels of oil per day, but a request to add facilities to increase throughput to a maximum of 60,000 barrels of oil per day has been requested.

Recent Permitting Actions (if any):
The latest modification to the refinery's Approval Order was issued in December of 2011. This source was listed specifically in prior SIP submittals. The refinery submitted a request for modification of its Approval Order in July of 2012. This request included an extensive BACT analysis. Results of this analysis are summarized below:

New process heaters CO Proper equipment design and operation, good combustion practices, and use of gaseous fuels.
PM10 Proper equipment design and operation, good combustion practices, and use of gaseous fuels.
SO2 Fuel gas sulfur content limit, with equipment design and work practice requirements to minimize emissions due to upsets.
NOx Low-NOx burners with selective catalytic reduction for large heaters. Ultra low-NOx burners for moderate-sized heaters.
VOC Proper equipment design and operation, good combustion practices, and use of gaseous fuels.
GHG Good combustion practices.
New boilers CO Good combustion practices.
PM10 Good combustion practices.
PM2.5 Good combustion practices.
SO2 Fuel gas sulfur content limit, with equipment design and work practice requirements to minimize emissions due to upsets.
NOx Low-NOx burners with selective catalytic reduction.
VOC Good combustion practices.
GHG Good combustion practices and use of gaseous fuels.
New cooling towers PM10 Drift eliminators.
PM2.5 Drift eliminators.
VOC Monitoring of cooling water returns for hydrocarbons.
Catalytic crackers CO Good combustion practices (full burn) and use of CO promoter.
PM10 Wet gas scrubber.
PM2.5 Wet gas scrubber.
SO2 PM10 Wet gas scrubber.
NOx Wet gas scrubber with selective oxidation.
GHG High efficiency regenerator and heat recovery.
Storage tanks VOC Fixed roof tanks for low volatility hydrocarbons. Floating roofs with primary and secondary seals for higher volatility hydrocarbons.

Emergency equipment	NOx	Ultra-low sulfur diesel fuel and limited annual hours of Operation.
	CO	Good combustion controls and limited annual hours of operation.
	VOC	Good combustion controls and limited annual hours of operation.
	PM10	Good combustion controls, ultra-low sulfur diesel fuel, and limited annual hours of operation.
	PM2.5	Good combustion controls, ultra-low sulfur diesel fuel, and limited annual hours of operation.
	SO2	Ultra-low sulfur diesel fuel.
Leaks	VOC	40 CFR Subpart GGGa for new equipment.
Flares	All	Proper design and good combustion practices.
	GHG	Flow monitors and steam controls.

Existing Actual Emissions (from 2008 inventory)

PM2.5	SO2	NOx	VOC
47.34	449.16	283.03	2332.20*

* Includes one-time breakdown release of 2144 tons.

Holly Corp: HRMC and HEP Woods Cross Operations

Year	PM2.5	SO2	NOx	VOC
2008	50.65	452.99	293.20	227.39
2014	43.07	65.14	292.70	211.62
2017	43.07	65.14	292.70	211.62
2019	43.07	65.14	292.70	211.62

Emissions Information / Discussion

Except for maintenance periods, operations are generally 24 hours per day, 365 days per year. The VOC emissions for 2008 were substantially out of agreement with other years due to an undiscovered leak in a heat exchanger that lost a significant amount of propane into the cooling water, which was subsequently vaporized into the atmosphere in a cooling tower. This type of occurrence is now prevented through regular monitoring. Multiple emissions controls on heaters, boilers, and the catalytic cracker have been employed since the 2008 inventory. Additional controls have been proposed as part of the pending request for modification of the Approval Order.

Results of Analysis

The following was determined to represent RACT for this source:

A second crude unit with a capacity of 15,000 barrels per day of crude will be installed along with a 60 MMBtu/hr crude heater (24H1). To improve recovery of gas oil from the crude distillation bottoms, a vacuum tower and vacuum furnace, with a rating of 130 MMBtu/hr will be installed. Emissions from the new heater will be controlled using Selective Catalytic Reduction (SCR).

The existing charge heater on the Gas Oil Hydrocracking Unit (GHC) will be replaced with a 42.1 MMBtu/hr reactor charge heater.

A Fluid Catalytic Cracking Unit (FCCU) with a capacity of processing 8500 barrels per day will be constructed along with a 45 MMBtu/hr feed heater. Emissions from the FCCU will be controlled by a wet gas scrubber.

A Hydrocracker/Hydroisom Unit which will produce high-quality lubricants and ultralow sulfur diesel will be constructed. This unit will be equipped with a 99 MMBtu/hr reactor charge heater. Emissions from this heater will be controlled using SCR.

n 89.3 MMBtu/hr steam boiler will be installed. Emissions from this boiler will be controlled through Selective Catalytic Reduction (SCR).

A sour water stripper with a capacity of handling 100 gallons per minute will be constructed. Emissions from this unit will be controlled through the existing sour water stripper/ammonia stripping unit prior to treatment in the existing sulfur recovery unit.

One new cooling tower will be constructed and one existing cooling tower will be expanded by adding a cell.

The 60 MMBtu/hr CO boiler will be decommissioned.

A previously permitted 15.3 MMBtu/hr asphalt mix heater will no longer be used.

The previously permitted heaters for the Hydrogen Plant will be controlled using SCR to reduce oxides of nitrogen emissions.

The previously permitted heater for the Deasphalting Unit hot oil heater will be controlled using SCR to reduce NOx emissions.

The previously permitted boiler #8 will be controlled using SCR to reduce NOx emissions.

The frozen earth propane storage will be removed.

Attachment #8

Cooling Towers ALL - 5 towers including #11
Holly Refining & Marketing

	PM10 Tons	PM2.5 Tons	SOx Tons	NOx Tons	VOC Tons	CO Tons	Lead Tons	Benzene Tons	Formalde. Tons	Hexane Tons	Toluene Tons	Arsenic Tons	Cadmium Tons	Chromium Tons	Cobalt Tons	Mercury Tons	Nickel Tons
2001	0	0	0	0	45.44	0	0	0	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	43.35	0	0	0	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	42.07	0	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	45.84	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	45.84	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	43.49	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	43.49	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	44.81	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	46.14	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	47.59	0	0	0	0	0	0	0	0	0	0	0	0

Assumptions:
Implementation of monthly cooling tower hydrocarbon monitoring.

2003	0.0000	0.0000	0.0000	0.0000	43.9535	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2004	0.0000	0.0000	0.0000	0.0000	45.8370	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2005	0.0000	0.0000	0.0000	0.0000	44.6635	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2006	0.0000	0.0000	0.0000	0.0000	43.4900	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2007	0.0000	0.0000	0.0000	0.0000	44.1500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2008	0.0000	0.0000	0.0000	0.0000	45.4750	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2009	0.0000	0.0000	0.0000	0.0000	46.8650	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	0.0000	0.0000	0.0000	0.0000	46.8650	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Attachment #9

Cooling Tower #4-#8 Emissions
Holly Marketing & Refining Company

Reference: South Coast Air Quality Management District, Guidelines for Calculating Emissions from Cooling Towers, June 2006
E = Cooling tower circulating water rate (gal/min) * TDS/10^6 * Drift loss * density of water * 60 * operating hours

$E_{(VOC)}$ =	9749.88	lb/yr	VOC Baseline 2008-2009 52.95 tons
$E_{(VOC)}$ =	4.87	tn/yr	-48.08 tons
$E_{(VOC)}$ =	1.11	lb/hr	

Where:

Water Circulating Rate (gal/min)	26,500
Concentration of Total Dissolved Solids (ppm by weight)	2064.9
Drift Loss of Circulating Water	0.000
Density of Water (lbs/gal)	8.34
Conversion of Minutes to Hours	60
Annual Operating Hours (hr/yr)	8760

Assumptions:
TDS was based on the average TDS of the existing cooling towers
HAP emissions estimated by Holly based on storage tank HAPs emissions determined using the TANKS software, averaging the last 8 years, and multiplying by 2 standard deviations.
VOC emission factor from AP-42 Section 5.1-2 controlled
Circulation rate for cooling towers 4-8