

US EPA ARCHIVE DOCUMENT

Greg Willms
General Manager



August 19, 2014

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CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. Jeffrey Robinson
Air Permits Section Chief
U.S. EPA Region 6, 6PD-R
1445 Ross Avenue
Dallas, TX 75202-2733

RECEIVED
14 AUG 22 AM 10:30
AIR PERMITS SECTION
6PD-R

Re: Motiva Enterprises LLC, CN600124051
Port Arthur Refinery, RN100209451
PSD Greenhouse Gas Permit Application – HCU2/DHT Expansion Project

Dear Mr. Robinson:

Motiva Enterprises LLC (Motiva) owns and operates a refinery in Port Arthur, Texas. Motiva is planning to expand the existing Hydrocracker 2/Diesel Hydrotreater Unit (HCU2/DHT) at this refinery. The greenhouse gas (GHG) emissions from the project are above the GHG significant emissions rate and will trigger Prevention of Significant Deterioration (PSD) for the project. Accordingly, Motiva is submitting this application for a PSD air quality permit for the GHG emissions from the proposed project.

This is a very important project to the economic viability of our facility and we desire to begin construction in April 2015. We are aware that US EPA is working to transition Texas GHG permitting to the Texas Commission on Environmental Quality (TCEQ) in the very near future. We look forward to working with U.S. EPA and TCEQ to assure that this project's GHG permitting is handled as expeditiously as possible.

From a GHG perspective, we don't think this will be a very complex permit review. The only substantial GHG PSD permitting requirement for this particular project is the need to implement best available control technology (BACT) for fugitive leaks of methane (a GHG) from the modified fugitive emissions source (CEP-FUG).

If you have any questions concerning this application, please contact Ms. Laurie Carpenter at (409) 989-7449 or Mr. Damian Fryoux at (409) 989-7174.

Sincerely,

MOTIVA ENTERPRISES LLC

A handwritten signature in black ink, appearing to be "G Willms", written over a horizontal line.

DMF:jmb

cc: Air Section Manager, Air Programs, TCEQ, OCE/FO Region X, 3870 Eastex Fwy, Beaumont, TX
77703-1830

Attachment



**Motiva Enterprises LLC
HCU2/DHT Expansion Project
Port Arthur Refinery
Prevention of Significant Deterioration
Greenhouse Gas Application**

August 2014

Prepared for:

Motiva Enterprises LLC
2555 Savannah Avenue
Port Arthur, Texas 77640

Prepared by:

URS Corporation
Houston, Texas and
Louisville, Kentucky

MOTIVA
ENTERPRISES LLC

URS

HCU2/DHT Expansion Project GHG PSD Permit Application

TABLE OF CONTENTS

SECTION 1.0 INTRODUCTION	5
SECTION 2.0 PROJECT DESCRIPTION	10
SECTION 3.0 EMISSIONS BASIS	13
SECTION 4.0 BEST AVAILABLE CONTROL TECHNOLOGY.....	17
SECTION 5.0 OTHER PSD REQUIREMENTS	21
APPENDICES	23
APPENDIX A: EMISSION RATE CALCULATIONS	1
APPENDIX B: TCEQ FORM PI-1	3
APPENDIX C: SEPARATE SOURCE EVALUATION (HYDROGEN).....	3

Section 1.0 Introduction

Motiva Enterprises LLC (Motiva) owns and operates a refinery in Port Arthur, Texas. This document is an application for a greenhouse gas (GHG) Prevention of Significant Deterioration (PSD) permit for the expansion of the existing Hydrocracker 2/Diesel Hydrotreater Unit (HCU2/DHT). (A separate PSD application for the non-GHG emissions of the project has been submitted to Texas Commission on Environmental Quality (TCEQ).)

There is no confidential information included in this submittal.

Project Overview

The existing HCU2/DHT is currently capable of approximately 82 KB/D feed rate. A new expansion project is planned that will increase the HCU2 capacity to a new design capacity of approximately 105 KB/D. Aside from the HCU2, this project will not change the capacity or maximum allowable emissions of any other process unit or emission source. Motiva desires issuance of required permits in time to support current plans to start construction in mid-2015.

PSD Applicability/Review

The actual emission increases due to this project are greater than the PSD major modification thresholds (SER) for conventional pollutants NO_x , SO_2 , and particulate matter (PM_{10/2.5}) and are addressed in a separate application submitted to Texas Commission on Environmental quality, TCEQ. Additionally, the project's emissions of CO_2e are above 75,000 tons/yr. Consequently, per current regulations and EPA guidance, the greenhouse gas emissions (CO_2e) of this project are subject to extra permit review elements associated with a PSD pre-construction review, namely the requirement to employ best available control technology (BACT). Table 2.1 (in the next section) shows a summary of the project emissions compared to these PSD applicability thresholds.

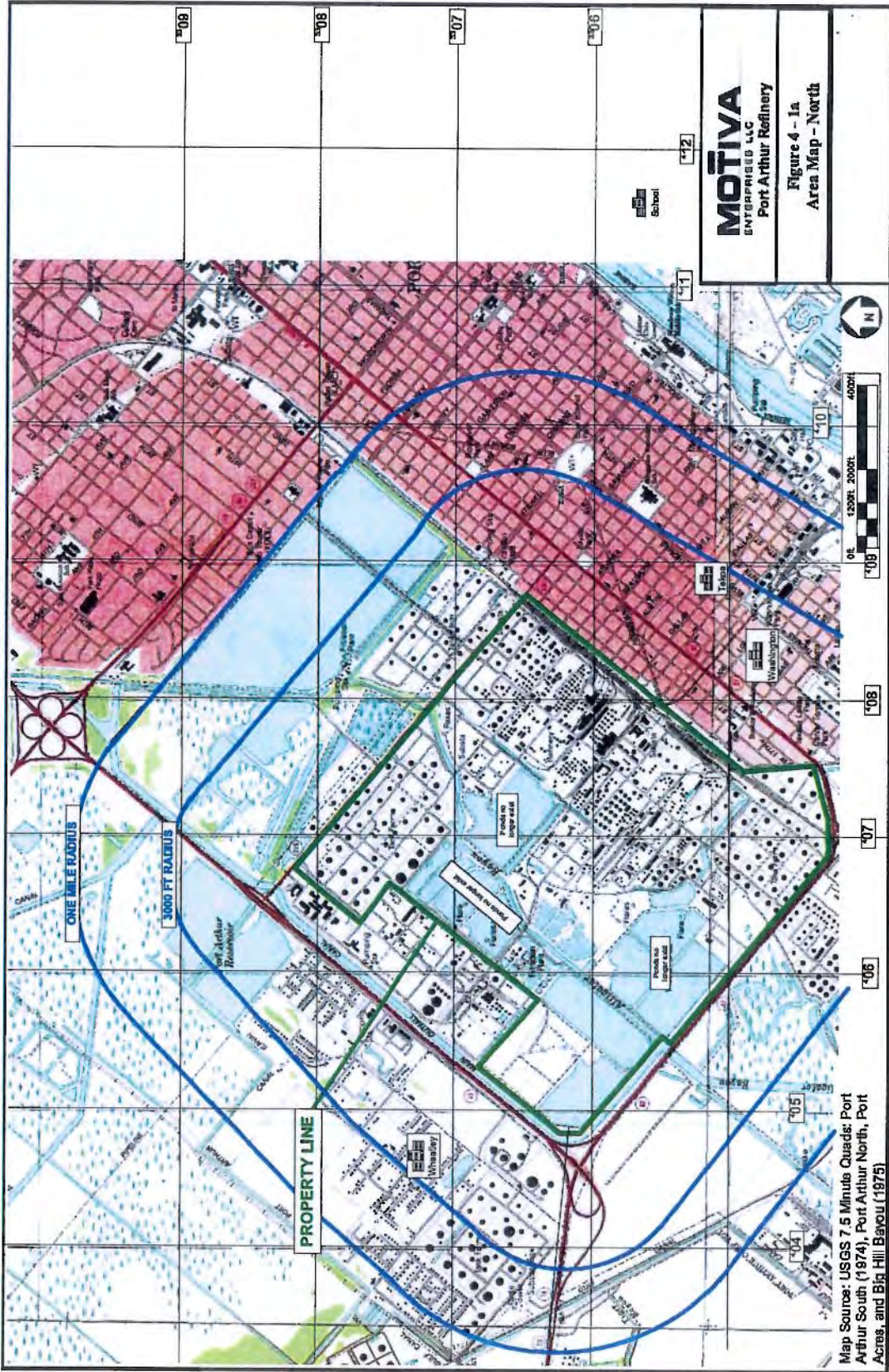
The only physical changes to the HCU2/DHT unit and other interconnected processes to accomplish this expansion involve only modifications to piping, pumps, exchangers, compressors, and other fugitive emission sources. Therefore, the only direct greenhouse gas emissions impact of the physical modification is a slight increase to the actual and allowable emissions from fugitive piping components at the refinery of 145 tons $\text{CO}_2\text{e/yr}$. This is only a small fraction of the GHG PSD significant emissions rate of 75,000 tons $\text{CO}_2\text{e/yr}$. However, in addition to the process fugitive piping changes, there are a number of upstream and downstream process units, process heaters, and other existing equipment that, although not modified, will increase their utilization and their actual emissions as a result of the expansion of the HCU2/DHT project. The total GHG emissions increases for these affected, but un-modified processes is approximately 400,000 tons $\text{CO}_2\text{e/yr}$. Therefore, this project triggers the requirement to employ BACT for its GHG emissions.

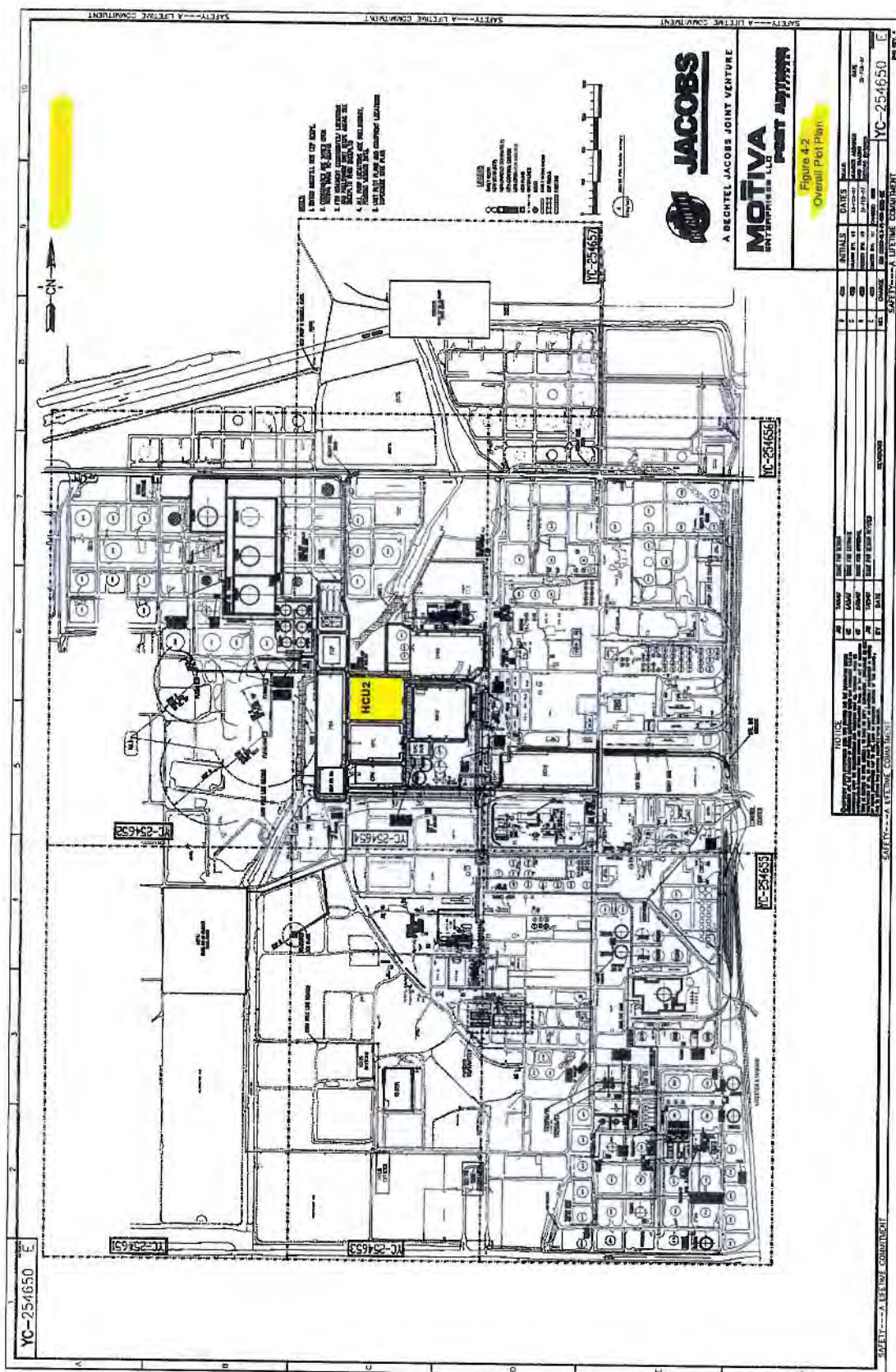
Although this project triggers PSD BACT for greenhouse gases, the BACT review for this particular project should be fairly straightforward. BACT is only required for sources that are modified. The only project source that is modified and has GHG emissions is the equipment leak fugitive emissions source (CEP-FUG). To date, the most common control measure in other BACT determinations for fugitive equipment leaks for complex facilities is the use of a leak detection and repair (LDAR) program. The current permit for this existing source already requires use of the TCEQ 28 MID LDAR program for fugitive emissions for the refinery— a level of control that is more stringent than is typically required as BACT for VOC. Section 3 of this application presents the BACT analysis for this modified GHG emission project and provides a further explanation of why the un-modified, but affected, sources (e.g.: heaters) do not trigger PSD BACT.

Site Description

The Motiva facility is located in Port Arthur, Texas which is in Jefferson County. The Port Arthur area is currently not designated as non-attainment for any pollutant. A copy of TCEQ form PI-1 is provided in Appendix B and contains further information regarding the site address, key contacts, SIC code, etc. The facility currently operates under the following air permits: Texas Commission on Environmental Quality (TCEQ) air permits: No. 8404 and 6056 and PSD permit PSD-TX-1062M1.

The following area map illustrates the location of the HCU2/DHT Expansion Project in relation to the surrounding area. In addition, on the next page, an area map is presented and indicates a 3,000-foot, 1-mile, and 3-kilometer radius from the Motiva Port Arthur Refinery. There are schools located within 3,000 feet of the facility. Following the area map, a plot plan is provided of the Motiva Port Arthur Refinery Plot Plan showing the location of the HCU2/DHT Expansion Project.





Section 2.0 Project Description

Motiva Enterprises LLC (Motiva) owns and operates a refinery in Port Arthur, Texas. Motiva is planning to expand the existing Hydrocracker 2/Diesel Hydrotreater Unit (HCU2/DHT). The greenhouse gas (GHG) emissions from the project are above the GHG significant emissions rate and will trigger prevention of Significant Deterioration (PSD) for the project. Accordingly, Motiva is submitting this application for a PSD air quality permit for the GHG emissions from the proposed project.

The existing Hydrocracker 2/Diesel Hydrotreater Unit (HCU2/DHT) was originally permitted as part of the Crude Expansion Project (CEP). That project was permitted in 2006 and began operation in 2012 expanding the already existing Motiva base plant. The HCU2/DHT (Hydrocracker 2 and integrated Diesel Hydrotreater.) was one of several new process units in that permit. This existing HCU2/DHT is currently capable of approximately 82 KB/D feed rate. A new expansion project is planned that will increase the HCU2 capacity to a new design capacity of approximately 105 KB/D. The current application represents a permit amendment application for the expansion of HCU2/DHT.

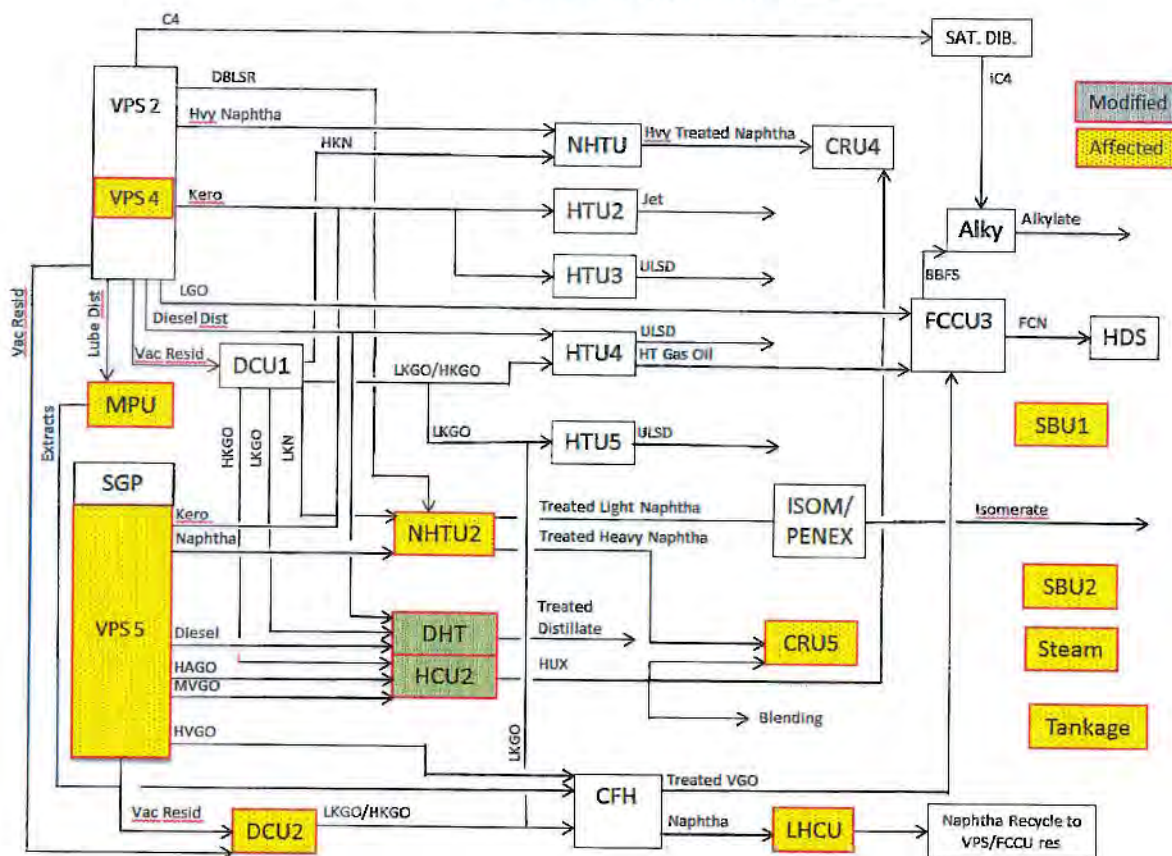
The existing Hydrocracking unit (HCU2/DHT) converts heavy, high boiling gas oils into lighter, more desirable products such as fuel gas, naphtha and diesel. Typical feedstocks consist of various gasoils (e.g. from VPS, DCU, FCCU, etc.), lube oil extract and H_2 . The HCU2 is a moderate temperature, high pressure, fixed bed catalytic cracking process. The unit consists of two main sections, the reactor section and the product recovery section. Feedstocks are mixed with hydrogen, heated, and in the first reactor, nitrogen and sulfur compounds are converted to ammonia and hydrogen sulfide and removed. In the second reactor, catalytic cracking and hydrogenation reactions take place under controlled temperatures and pressures to produce the desired products. The unit also has an integrated diesel hydrotreating section that processes the cracked and straight-run diesel feedstocks. The overall operation of the unit will not be changed by this project other than an increase to its capacity.

The physical changes to the HCU2/DHT unit to accomplish this expansion will involve changes to piping, pumps, exchangers, compressors, and other fugitive emission sources. Additionally, some tower internals will be modified or replaced. One new process vessel is expected to be installed. The only direct emissions impact of the physical changes is a slight increase to the actual and allowable emissions from fugitive piping components. These increases are primarily in the HCU2/DHT process unit, but also include some minor piping modifications outside the HCU2/DHT battery limits. In addition to the changes to the CEP fugitive emissions (CEP-FUG which includes HCU2 fugitives) covered in TCEQ permit 6056, a few project piping changes are being considered in the base plant (currently covered in separate TCEQ Permit 8404).

This project will not modify any process heaters, reactors, or other emission sources besides the above described fugitive sources in any other Motiva refinery process unit. Accordingly, this project will not change the allowable emissions rates of any other facility equipment. The expansion of the HCU2/DHT unit will not involve any physical changes, besides those noted above, at any other emission sources. However, the HCU2/DHT's increased capacity is expected to increase the utilization of some upstream and downstream units. Increases to the actual feed rates of the upstream and downstream sources will result in increases to their actual emission rates, but not above already permitted and allowable levels. This project does not remove any capacity limitations or change the effective capacity of any of these unmodified units. Similarly, this project will not result in any changes to maintenance, startup, or shutdown (MSS) emission rates.

The following is a process flow diagram for the HCU2/DHT Expansion Project. The PFD shown below represents the new, modified and affected facilities for this project.

Motiva Refinery Process Flow Diagram



Emissions Impacts

The only project related emission increase to allowable emissions is approximately 1.05 tons/yr increase to VOC emissions and 145 tons/yr of CO₂e from process fugitive piping components. However, as mentioned previously, there are a number of upstream and downstream process units and other existing equipment that will increase their utilization as a result of this project. Although the allowable emissions of those unmodified units will not change, there will be an increase to their actual emissions resulting from their increased utilization.

The total emissions impacts to both modified and unmodified sources are presented in the following Table 2.1 and have been considered in the Prevention of Significant Deterioration (PSD) and the Nonattainment New Source Review (NNSR) applicability reviews discussed next.

Table 2.1 Summary of All Project and Related Emissions Impacts

Project Scope Element	NOx	CO	PM10/2.5	VOC	SO2	CO2e	H2SO4
	Tons/yr	Tons/yr	Tons/yr	Tons/yr	Tons/yr	Tons/yr	Tons/yr
Modified Unit							
CEP-FUG Equip. Fugitives (primarily HCU2/DHT)				1.05		145	
Non-CEP Fugitive (estimate)				<0.2			
UnModified w/Increased Use							
HCU2 Heaters	35.38	3.87	8.43	3.05	25.08	141,450	0.38
CRU5 Heaters	16.80	2.30	5.01	1.81	14.89	84,000	0.23
SVPS4 Heaters	6.81	7.17	0.65	0.47	1.93	10,881	0.03
MPU 3 & 4 Heaters	4.23	5.49	0.50	0.36	1.48	8,337	0.02
VPS5 Heaters	15.16	1.48	3.23	1.17	9.60	54,277	0.73
HTU4-LT (Lube train) Heaters	0.16	1.51	0.14	0.10	0.41	2,293	0.01
DCU2 Heaters	4.04	0.40	0.86	0.31	2.56	14,435	0.04
NHTU2 Heaters	4.11	0.56	1.22	0.44	3.64	20,531	0.06
Incremental Steam Generation	6.85	12.50	10.89	1.90	8.79	45,955	2.50
SBU 1 and 2	6.56	15.50	0.61	0.44	88.55	17,725	1.36
Cooling Towers Increase			0.22/0.001	0.46			
Increased Tank Throughput				3.72			
Project Total	100.1	50.8	31.8/31.5	15.5	156.9	400,028	5.36
PSD Significant Emiss. Rate	40	100	15/10	40	40	75,000	7

The expanded HCU2/DHT operation will also require the supply of additional hydrogen (H₂) for use by this unit. There are currently multiple outside industrial gas suppliers that service Motiva's H₂ needs (as well as the needs of other regional petroleum and chemical facilities). It is anticipated this project's needs for hydrogen will either be supplied by the existing capacity of outside suppliers, or a supplier will build a new hydrogen production unit to meet this increased demand. In either case, any increased emissions from the production of extra hydrogen would not occur at a facility under Motiva's common control and any associated emissions would be considered "secondary emissions" for this project as explained further in Appendix C.

Although this project will result in some increased product rates (primarily diesel/distillate), it is not expected to result in an increased throughput at the nearby Motiva Port Arthur Terminal (PAT). This marine terminal loads a portion of the liquid products from Motiva's Refinery onto ships and barges for transport to customers. However, the vast majority of the refinery's products are instead shipped from the refinery by pipeline, not over this dock. The volume of products shipped by marine vessels is a function of customer location and market conditions. The volume of products shipped over this dock is not expected to change as a result of this current project. (Also note that the Port Arthur Terminal is on a separate property which is not contiguous with the refinery and has historically been treated as a separate facility from the refinery for permitting purposes. But regardless, no changes to operations at the PAT are expected as a result of this project.)

Section 3.0 Emissions Basis

Detailed calculations for GHG emissions (as well as other pollutants) from the proposed project are presented in Appendix A. A brief summary of the basis of the GHG emissions estimates is presented below.

Heater/Boiler: The primary emissions of GHGs are those from increased heater and boiler firing. Combustion of refinery fuel gas in the heaters results in emissions of CO₂ and small amounts of N₂O and methane. GHG emissions were calculated by taking the increased firing rate of heaters and boilers and multiplying it by the following emissions factors.

- For heater firing: 125 lbCO₂e/MMBtu (based on 124.44 lb CO₂/mmbtu, 0.17 lb CH₄/mmbtu, and 0.39 lb N₂O/mmmtu.)
- For boiler firing: 122 lbCO₂e/MMBtu (based on 121.44 lb CO₂/mmbtu, 0.17 lb CH₄/mmbtu, and 0.39 lb N₂O/mmmtu.)

Methane and N₂O factors are from the EPA Mandatory GHG Reporting Rule (40 CFR Part 98 Subpart C Table C-2 and assume a global warming potential for methane of 25 and N₂O of 298.) CO₂ factors are conservatively based on past actual refinery data. Firing rates are based on expected increased firing rates resulting from this project.

Sulfur Block Units (SBU): This project will result in increased loading to the existing unmodified sulfur recovery units. The incremental CO₂ emissions estimates are based on emissions factors of 875 lb/LTPD (or 36.46 lb/hr per long tons of sulfur loading). This factor is based on SRU design information and is typical for refinery SRU's. Some of this CO₂ is a result of combustion of supplemental fuel in the tail gas incinerator. Additionally, some of the CO₂ is from combustion of organic impurities in the acid gas feed to the SRU Claus process. The emission factor used reflects the total GHG from both these mechanisms.

Fugitive Equipment Components

Fugitive emission from some of the piping components in gaseous service will contain some methane a GHG. GHG emissions were estimated assuming that on average, the project's piping in gas service contains 50% methane. Total emissions rates were estimated using the general methodology outlined in the *TCEQ's Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000*, but using site-specific experience-based control efficiencies negotiated with TCEQ based on EPA's correlation equations and Motiva's actual monitoring data.

An uncontrolled total hydrocarbon emission rate was estimated by multiplying the number of fugitive components of a particular equipment type by the US EPA Refinery Average Emission Factor in the TCEQ guidance document for that component type. Next, the controlled fugitive emission rates were calculated using site-specific experience-based control efficiency factors negotiated with TCEQ in the most recent past permit application for Permit 6056. Those control efficiencies are based on actual fugitive monitoring data from Motiva units in the PAR Base Plant employing the 28MID LDAR program. The actual monitoring data shows that the actual leak control effectiveness at Motiva operating the 28MID LDAR requirements is much better than the default 28MID control efficiencies in TCEQ's

guidance documents. For conservatism, the site-specific control efficiencies only take credit for 65% of the improvement shown in the monitoring data. (i.e.: site-specific control factors = TCEQ default efficiency + 65% of the difference between (1) the actual measured efficiencies and (2) the TCEQ default efficiencies). For example, the Motiva site-specific control efficiency of 98.7% for valves in gaseous service was derived from TCEQ default factor of 97% and actual measured values of 99.644%. Speciated emissions of methane were estimated using an assumed average stream composition for the HCU2 Process Unit of 50% methane (gas/vapor components only).

Approach used for Unmodified Sources with Increased Utilization

The following paragraphs explain the “increased utilization” emissions estimation approach used for calculating project emissions increases for existing equipment which is not being modified, but which will see increased utilization due to this project. This description applies to the following unmodified sources: steam utilities, sulfur recovery units, and process heaters. Increases to the actual utilization of these existing, unmodified refinery sources will result in increases to their actual emission rates, but not above already permitted and allowable emission rates. This project does not remove any capacity limitations or change the effective capacity of any of these unmodified units. Therefore, these upstream and downstream impacts do not fall within the common concept of “debottlenecking”. Nevertheless, it is expected that these unmodified sources will experience an increase in their current operating rates and emissions as a result of this project. Consequently, for PSD applicability and air dispersion modeling purposes, Motiva has estimated the maximum emissions increase expected at these emission units due to their increased utilization as a result of the proposed project.

Multiple EPA guidance documents outline the appropriate procedure for unmodified sources with increased utilization. For example, as explained in a July 25, 2001 letter from Rebecca Weber of US EPA to Ms. Higgins of Louisiana DEQ regarding a Motiva Enterprises Low Sulfur Gasoline Project:

“In the case of the existing equipment not undergoing a change, but whose emission levels could be affected by the change at the facility (e.g., because of increased demand for steam and other products), emissions increases should be calculated as the worst case increases that could occur at those existing units if the new or modified units were to operate at their maximum permitted capacity.” (emphasis added)

Similar guidance is provided in other EPA guidance documents such as the Sept. 17, 1993 letter by US EPA’s Joel Luehrs to Louisiana DEQ regarding Union Carbide, and the February 24, 2005 letter from US EPA’s Sam Portanova to the Wisconsin DNR regarding Murphy Oil.

The purpose of this methodology for unmodified units with increased utilization is to assure that the permit review considers the full emissions increases that may occur at these units as a result of the project, without having to “re-permit” the entire un-utilized capacity of these unmodified sources.

For unmodified heaters, Motiva’s engineering staff evaluated the maximum feed rate impact that the proposed expansion of the HCU2/DHT unit could have on each refinery process unit. Motiva estimates that the proposed expansion of the HCU2/DHT unit will affect the following existing refinery units, and that the expansion, if operated at its new maximum design rate will result in no more than the following

maximum feed rate increases to these affected upstream/downstream unmodified processes when the HCU2/DHT expansion is operating at maximum rates.

Table 3-1

Incremental Feed Rate Increase for Upstream/Downstream Emissions Units

	Max. Possible Rate Increase from HCU2 Expansion KB/D
<u>CEP Units Affected</u>	
HCU2/DHT	23
CRU5	17.5
VPS5	30.0
NHTU2	12.0
DCU2	4
<u>Base Plant Affected</u>	
VPS4	10
MPU3	1.9
MPU4	
HTU4 LT (Lube Plant)	0.84

Note: Actual increases to these process units due to this project may be significantly less than shown above (or even zero) since Motiva has the capability to purchase and/or sell intermediate feedstocks. These intermediate feedstock/product sales functionally delink upstream and downstream units from being affected by other unit changes. Nevertheless, for conservatism, Motiva has evaluated emissions associated with these maximum upstream and downstream rate changes that could result from the HCU2/DHT expansion project.

Each of these process units has one or more process heaters supporting its operation. Motiva has determined the maximum incremental heater firing rate for each heater needed to accommodate the increased feed rates in Table A-1 for each of the potentially affected process units. The GHG emissions increase for each of these heaters is then calculated using appropriate GHG emissions factors (lbs/MMBtu) multiplied by the maximum incremental firing rate (MMBtu/hr) for each heater. Documentation of these maximum incremental firing rates and all emissions factors is presented in Appendix A.

For estimating GHG emissions from the Sulfur Recovery Unit and Steam generation, Motiva's engineering staff evaluated the maximum potential rate impact that the proposed expansion of the HCU2/DHT unit could have on these unmodified refinery infrastructure systems. Motiva estimates that the proposed expansion of the HCU2/DHT unit will require increases of no more than the following maximum rate increases to these systems. GHG emissions are based on the previously described GHG emissions factors for these units multiplied by these unit rates.

Table 3-2

	Max. Possible Rate Increase from Expansion
Sulfur Plants (LTPD)	
SBU1 (LTPD)	6 LTPD
SBU2 (LTPD)	105 LTPD
Incremental Utility Needs	
Steam (Klb/hr 1500#) (from Power Station #4)	86 Klb/hr

LTPD is long tons per day

Klb/hr is thousand pounds per hour

Routine Maintenance, Startup, and Shutdown (MSS)

MSS emissions have historically been represented in Motiva's annual emissions inventory submittal and will continue to be included. This project will not affect MSS emissions. There are no proposed changes to existing MSS emissions or new MSS emissions associated with this permit action.

Section 4.0 Best Available Control Technology

As part of the air permitting process, Prevention of Significant Deterioration (PSD) regulations requires that all new and modified emissions sources which have increased emissions of PSD regulated pollutants must use best available control technology (BACT). The control technology evaluation process considers the technical practicality and economic reasonableness of reducing emissions. According to US EPA guidance following the June 23, 2014 Supreme Court decision regarding EPA's authority to regulate GHGs, the PSD BACT requirement applies to greenhouse gas (GHG) emissions for this project because it triggers PSD for at least one conventional pollutant and its GHG emissions are above 75,000 tons/year of CO₂e. This project also triggers PSD BACT for criteria pollutants NO_x, SO₂, and PM_{10/2.5}. A criteria pollutant and GHG BACT analysis was submitted by Motiva to TCEQ as part of a separate TCEQ air permit application. As described later in this section of this application, for this project, the controls considered as BACT for criteria pollutants also serve to minimize GHGs. The GHG elements of this project's BACT analysis are presented here in support of the GHG PSD permitting.

BACT Affected Sources

BACT is assessed on an emissions unit basis, not on a plant-wide basis, and applies only to new and modified sources. The requirement to implement BACT does not apply to a facility's existing unmodified sources. The applicability of BACT to only new and modified sources is clarified in Texas and Federal rules in the below references:

40 CFR 52.21(j)(3)

This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit. (emphasis added).

30 TAC 116.10 Definitions (1)

Best available control technology (BACT)--An air pollution control method for a new or modified facility. . .

TCEQ BACT Guidance Documentⁱ, (page 20 of 51)

The BACT requirement applies to each individual new or modified affected facility and pollutant emitting activity at which a significant net emissions increase would occur. . .

Therefore, BACT is not required of existing sources at the facility, unless they are modified, i.e. unless they have a "physical change or change in the method of operation".

For this project, the only emissions source that is being physically modified is the fugitive piping components of the CEP Plant (primarily in the HCU2/DHT process unit). For that process unit, this project scope includes the addition of some piping, pumps, heat exchangers and other fugitive emission sources as well as replacement of some existing similar types of components. The result of these changes

will be an increase in fugitive VOC emissions and a small amount of fugitive methane, a greenhouse gas. Since this emission source is being modified, BACT applies to its emissions.

None of the other project “affected” sources are being physically modified. As described elsewhere in this application, a number of upstream and downstream units are expected to have increased utilization associated with this project, but none are being modified. For example, although a number of upstream process heaters and boilers may increase their actual firing rate, resulting in increased actual combustion emissions (e.g. GHG, NO_x, SO₂, CO, etc.), none of these sources are being physically modified.

Likewise, their maximum potential and allowable firing rates will not change, nor are there changes to their allowable emissions. Absent a physical change or an increase in allowable emissions, a simple increase in their actual firing rate, production rate, or hours of operation, by itself, is not considered a “modification” – and would not trigger a BACT requirement as part of this permitting effort. Most of these affected unmodified existing units already meet BACT for their criteria pollutants because they were permitted as part of the Crude Expansion Project (CEP), permitted originally in 2006 with the most recent permit amendment in 2013. Through that permitting process, as new equipment, they were required to implement BACT. But regardless, since they are not being modified by this new project, a re-evaluation of BACT is not required.

In summary, as described above, the only project emissions source requiring a BACT analysis as part of this permitting is the VOC and GHG emissions from the process fugitives. The below section addresses BACT for this source.

BACT for HCU2/DHT (CEP-FUG) Process Equipment Fugitive Leaks of VOC and Methane (GHG)

The HCU2/DHT was installed as part of the Crude Expansion Project (CEP) and underwent a VOC BACT review at that time, 2006, and in subsequent permit amendments, most recently in 2013. In those previous permitting actions, Motiva agreed to implement a “beyond BACT” level of emissions controls on the fugitive equipment leaks for this unit (as well as other CEP processes). Accordingly, the current permit for this process unit already requires use of the TCEQ “28 MID” leak detection and repair (LDAR) program plus a number of enhancements that further reduce emissions.

The use of a comprehensive LDAR programs serves to control all pollutants contained in the process piping. In this case, the primary piping constituent is VOC, and LDAR will serve to minimize it’s emissions. Additionally, some of the piping components in gaseous service at the refinery contain methane, a greenhouse gas. Use of an LDAR program minimizes those emissions as well.

The use of a 28 MID LDAR program results in lower emissions than would otherwise be required per TCEQ’s Tier I BACT guidance. Specifically, TCEQ’s BACT Guidelines outlined in *“TCEQ Chemical Sources, Current Best Available Control Technology (BACT) Requirements, Equipment Leak Fugitives”*ⁱⁱⁱ (updated 8-1-2011) require the largest facilities (those with more than 25 tpy of VOC fugitive emissions) to implement at least the 28VHP leak detection and repair (LDAR) program. The 28 MID LDAR program that Motiva uses is more stringent than the 28 VHP program. Continued use of the 28 MID LDAR program and the other currently required enhancements is proposed as BACT for the VOC emissions from the new and replaced components of the modified HCU2/DHT process unit.

The 28 MID LDAR program is more stringent than the 28 VHP program in the following ways:

- 28 MID has a lower leak definition for pumps and compressors (500 ppmv) vs. the 28 VHP (2000 ppmv)
- 28 MID requires the use of directed maintenance for repairing any leaking components. Directed maintenance requires a two-person team to repair leaking components. One person performs the actual repair while the other uses instrument monitoring to identify the lowest corrected VOC concentration. This eliminates the possibility of over-correcting (i.e., over-tightening the leaking component) and should result in lower levels of fugitive emissions.

Additionally, the following additional enhancements are required by the existing Motiva permit, and are proposed to remain as part of the BACT commitment for this unit:

- Quarterly instrument monitoring of valves in heavy liquid service. Other applicable regulations would otherwise not require any monitoring of components in heavy liquid service – which generally have much lower VOC emissions than light liquid or gaseous service components.
- Quarterly instrument monitoring of flanges/connectors and process drains using a leak definition level of 500 ppmv. TCEQ requirements would otherwise only require flanges/connectors to be only monitored by audio/visual/olfactory (AVO) methods and process drains only monitored annually.

Other major elements of the standard 28 MID program include the following:

1. All valves in light liquid or gaseous service must be monitored quarterly for leaks using an approved gas analyzer unless they are equipped with either a sealless or leakless system;
2. For valves, a leak is defined as any detected emissions above 500 ppmv.
3. All pump and compressor seals must be equipped with a leakless shaft sealing system;
4. Any damaged or leaking components must be tagged and repaired or replaced;
5. First attempts-at-repair must occur within 5 days after detection, except when a process unit shutdown is required to make the repair;
6. Final repairs must be completed and rechecked within 15 days to insure the components are not leaking;
7. Each open-ended valve or line must be equipped with a cap, blind flange, plug, or a second valve; and
8. Each relief valve must be equipped with a rupture disc upstream or be vented to a control device.

In addition to being more stringent than TCEQ BACT guidance, this level of control is equivalent or more stringent than Federal MACT standards. The use of MACT level LDAR controls (40 CFR Part 63 Subpart H, or 40 CFR Part 63 Subpart CC) is consistent with or more stringent than almost all BACT determinations in EPA's RACT/BACT/LAER Clearinghouse (RBLC) Database for VOC control.

Likewise, the use of LDAR controls for minimizing fugitive piping leaks of greenhouse gases is specified in many, but not all, GHG BACT determinations (particularly for facilities already required to use LDAR under applicable VOC regulations.) The use of the proposed LDAR program for GHG BACT would be more stringent than most GHG BACT determinations for fugitive piping leaks.

Based on the above analysis, BACT for VOC and Methane (GHG) emissions from the HCU2/DHT (CEP-FUG) equipment fugitive emissions is proposed to be continued use of the 28 MID LDAR program with the currently-required enhancements.

Section 5.0 Other PSD Requirements

5.1 Air Quality Impacts Analysis

A greenhouse gas air quality impacts analysis is not required to be provided in accordance with EPA's document "PSD and Title V Permitting Guidance for Greenhouse Gases, March 2011" (Pages 47& 48):

"Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause or contribute to a violation of the NAAQS are not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO₂ or GHGs".

5.2 GHG Preconstruction Monitoring

A pre-construction monitoring analysis for GHG is not required with this application in accordance with EPA's document PSD and Title V Permitting Guidance for Greenhouse Gases, March. 2011(Page 48):

"Monitoring for GHGs is not required because EPA regulations provide an exemption in sections 52.21(i)(5)(iii) and 51.166(i)(5)(iii) for pollutants that are not listed in the appropriate section of the regulations, and GHGs are not currently included in that list. However, it should be noted that sections 52.21(m)(1)(ii) and 51.166(m)(1)(ii) of EPA's regulations apply to pollutants for which no NAAQS exists.

These provisions call for collection of air quality monitoring data "as the Administrator determines is necessary to assess ambient air quality for that pollutant in any (or the) area that the emissions of that pollutant would affect." In the case of GHGs, the exemption in sections 52.21(i)(5)(iii) and 51.166(i)(5)(iii) is controlling since GHGs are not currently listed in the relevant paragraph.

Nevertheless, EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs."

5.3 PSD Additional Impacts Analysis

A PSD additional impacts analysis is not required with this application in accordance with EPA's document "PSD and Title V Permitting Guidance for Greenhouse Gases", March 2011 (Page 48):

"Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including

impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.”

5.4 Biological and other Assessments

EPA permitting of this Project is a federal action which requires a review of other possible impacts. Motiva has retained the services of URS Corporation to prepare a separate report addressing each of the following areas where applicable. Motiva will submit these analyses once they are completed.

Endangered Species Act (ESA): A biological assessment (BA) will address the project’s potential to adversely affect federally-protected species, proposed species, or designated critical habitat.

Magnuson-Stevens Fishery Conservation and Management Reauthorization Act: The biological assessment will address the project’s potential to adversely affect Essential Fish Habitat (EFH).

National Historic Preservation Act: The project will not have the potential to impact any historic properties. All construction activity will occur within existing process units and tankage areas of the refinery. The general visual character of the facility will be unchanged. No new land will be disturbed.

APPENDICES

In this Section

The following is a list of topics in the appendices:

Description	Page Number
Appendix A: Emission Calculations	A-1
Appendix B: TCEQ Form PI-1	B-1
Appendix C: Separate Source Evaluation for Hydrogen Production Emissions	C-1

Appendix A: Emission Rate Calculations

Table A-1: Summary of HCU2 Expansion Project Emission Increases

Project Scope Element	NOx	CO	PM/PM10	PM2.5	VOC	SO2	CO2e	H2SO4
	Tons/yr	Tons/yr	Tons/yr	Tons/yr	Tons/yr	Tons/yr	Tons/yr	Tons/yr
Modified Unit								
CEP-FUG Equip. Fugitives (primarily HCU2/DHT)					1.05		145	
Non-CEP Fugitive (estimate*)					0.20			
UnModified w/Increased Use								
HCU2 Heaters	35.38	3.87	8.43	8.43	3.05	25.08	141,450	0.38
CRU5 Heaters	16.80	2.30	5.01	5.01	1.81	14.89	84,000	0.23
SVPS4 Heaters	6.81	7.17	0.65	0.65	0.47	1.93	10,881	0.03
MPU 3 & 4 Heaters	4.23	5.49	0.50	0.50	0.36	1.48	8,337	0.02
VPS5 Heaters	15.16	1.48	3.23	3.23	1.17	9.60	54,277	0.73
HTU4-LT (Lube train) Heaters	0.16	1.51	0.14	0.14	0.10	0.41	2,293	0.01
DCU2 Heaters	4.04	0.40	0.86	0.86	0.31	2.56	14,435	0.04
NHTU2 Heaters	4.11	0.56	1.22	1.22	0.44	3.64	20,531	0.06
Incremental Steam Generation	6.85	12.50	10.89	10.89	1.90	8.79	45,955	2.50
SBU 1 and 2	6.56	15.50	0.61	0.61	0.44	88.55	17,725	1.36
Cooling Towers Increase			0.22	0.0013	0.46			
Increased Tank Thruput					3.72			
Project Total	100.1	50.8	31.7	31.5	15.49	156.9	400,028	5.36
PSD Significant Emiss. Rate	40	100	15	10	40	40	75,000	7

Note: Non-CEP Fugitives: A few project piping changes are being considered in the base plant (covered in separate Permit 8404). The emissions increase of such possible piping changes is expected to be insignificant. They are included in the above table for PSD applicability evaluation of this project, however, they are not otherwise addressed in this application for a revision to CEP Plant Permit 6056. Once the project design is further developed, if the scope indeed includes base plant fugitive changes, they will be authorized separately by a PBR and updated in the relevant Permit 8404.

Table A-3: Summary of HCU2 Expansion Project Heater Emission Increases

FIN	FEW	Description	Dates Available for Calculation	NO _x (lb/hr)		CO (lb/hr)		PM ₁₀ (PM _{2.5})		VOC		SO ₂		CO _{2e} (mt)		H ₂ SO ₄	
				lb/hr	ipy	lb/hr	ipy	lb/hr	ipy	lb/hr	ipy	lb/hr	ipy	lb/hr	ipy		lb/mtbbl
HCU1H1A	SHCU1-1	HCU No. 2 1st Stage Charge A HTR	21.1.9	0.75	2.34	0.073	0.321	0.159	0.688	0.115	0.253	0.797	14.34	2.077	125	11,712	1%
HCU1H1B	SHCU1-2	HCU No. 2 1st Stage Charge B HTR	24.3.6	0.65	2.67	0.063	0.365	0.182	0.795	0.131	0.298	0.907	16.33	2.365	125	13,337	1%
HCU1H2	SHCU1-3	HCU No. 2 2nd Charge Heater	27.3.2	0.86	2.88	0.084	0.410	0.204	0.891	0.147	0.323	1.018	18.32	2.652	125	14,856	1%
SHCU1D-5	SHCU1-5	HCU No. 2 Fractionator Heater	16.1.85	5.66	24.81	0.554	2.427	1.206	5.282	0.873	1.911	8.028	108.52	15.712	125	88,611	1%
HCU1DHTH1	SHCU1-6	HCU No. 2 DHT Charge Heater	23.4.4	0.82	2.57	0.080	0.351	0.175	0.765	0.126	0.277	0.979	15.72	2.276	125	12,835	1%
CRUSINTHT1	SCU5-1	#5 CRU Platformer No.1 Intermediate HTR	53.3.3	1.66	5.78	0.181	0.792	0.394	1.724	0.285	0.624	1.968	35.42	5.129	125	28,924	1%
CRUSINTHT2	SCU5-2	#5 CRU Platformer No.2 Intermediate HTR	34.5.9	1.22	3.83	0.120	0.525	0.265	1.142	0.189	0.413	1.303	23.46	3.398	125	19,155	1%
CRUSINTHT3	SCU5-2	#5 CRU Platformer No.3 Intermediate HTR	4.1.3	0.14	0.45	0.014	0.602	0.031	0.135	0.022	0.049	0.154	2.77	0.401	125	2,264	1%
CRUSP1ATH1	SCU5-1	#5 CRU Platformer Heater	61.4.7	2.15	6.73	0.210	0.922	0.458	2.005	0.331	0.726	2.290	41.22	5.988	125	33,657	1%
SVPS4-1	SVPS4-1	VPS No. 4, No. 3 (Atmospheric C Heater)	3.4.4	0.21	0.90	0.283	1.241	0.026	0.112	0.019	0.081	0.128	2.31	0.334	125	1,883	1%
SVPS4-2	SVPS4-2	Atmospheric A Heater (No. 1)	4.0.7	0.16	0.71	0.335	1.469	0.030	0.133	0.022	0.096	0.152	2.73	0.395	125	2,230	1%
SVPS4-3	SVPS4-3	Atmospheric B Heater (No. 2)	4.0.3	0.24	1.06	0.332	1.453	0.030	0.131	0.022	0.095	0.150	2.70	0.391	125	2,208	1%
SVPS4-5	SVPS4-4	VPS No. 4 Naphtha Splitter Reboiler	0.34	0.06	0.25	0.078	0.340	0.007	0.031	0.005	0.022	0.035	0.63	0.091	125	516	1%
SVPS4-6	SVPS4-5	Vacuum Heater A (No. 1)	3.5.8	0.43	1.68	0.285	1.283	0.117	0.019	0.005	0.134	2.40	0.348	125	1,962	1%	
SVPS4-6	SVPS4-6	Vacuum Heater B (No. 2)	3.8.1	0.46	2.00	0.314	1.373	0.028	0.124	0.021	0.090	0.142	2.55	0.370	125	2,084	1%
MPU1ROH1R	SNPU3-1	MPU Refined Oil Mx Heater	3.1.5	0.25	0.09	0.260	1.137	0.023	0.103	0.017	0.074	0.117	2.11	0.308	125	1,726	1%
MPU1ROH1R	SNPU3-2	MPU No. 3 Extract Heater	6.3.8	0.51	2.24	0.326	1.304	0.048	0.208	0.034	0.151	0.238	4.28	0.620	125	3,497	1%
MPU1ROH1R	SNPU4	MPU No. 4 Secondary Refill	0.1.5	0.01	0.05	0.012	0.054	0.001	0.005	0.001	0.004	0.008	0.10	0.015	125	82	1%
MPU1ROH1R	SNPU4	MPU No. 4 R.O. Heater	0.7.6	0.06	0.27	0.064	0.280	0.006	0.025	0.004	0.018	0.028	0.52	0.075	125	425	1%
SNPU4C	SNPU4C	MPU No. 4 extract heater	4.7.8	0.88	1.67	0.392	1.718	0.035	0.155	0.026	0.112	0.177	3.19	0.462	125	2,807	1%
SHTU4-3	SHTU4-3	Reboiler Heater	0.92	0.04	0.16	0.075	0.330	0.009	0.030	0.006	0.022	0.034	0.61	0.093	125	501	1%
SHTU4-4	SHTU4-4	Recycle Gas Heater	3.2.7	0.13	0.09	0.270	1.181	0.031	0.107	0.027	0.077	0.122	2.20	0.318	125	1,792	1%
VPS5H1/2	VPS5-1	VPS No. 5, No. 1/2 Atmospheric Heater	36.1.0	1.26	5.53	0.124	0.541	0.089	1.178	0.195	0.428	1.345	24.21	3.505	125	18,768	5%
VPS5H3/4	VPS5-1	VPS No. 5, No. 3/4 Atmospheric Heater	34.4.2	1.20	5.28	0.118	0.516	0.255	1.123	0.186	0.406	1.282	23.08	3.341	126	18,895	5%
VPS5VAC1HT	VPS5-2	VPS No. 5, No. 1 Vacuum Heater	15.2.8	0.53	2.34	0.092	0.229	0.114	0.498	0.092	0.180	0.569	10.23	1.482	125	8,356	5%
VPS5VAC2H1	VPS5-2	VPS No. 5, No. 2 Vacuum Heater	13.2.8	0.46	2.00	0.045	0.196	0.097	0.427	0.071	0.154	0.487	8.77	1.269	125	7,159	5%
SDCU2-1	SDCU2-1	Coker Heater No.1	8.5.7	0.30	1.31	0.029	0.129	0.064	0.280	0.046	0.101	0.319	5.75	0.832	125	4,693	1%
SDCU2-2	SDCU2-2	Coker Heater No.2	8.8.6	0.31	1.36	0.030	0.133	0.066	0.289	0.048	0.105	0.330	5.94	0.860	125	4,851	1%
SDCU2-3	SDCU2-3	Coker Heater No.3	8.9.3	0.31	1.37	0.031	0.134	0.067	0.292	0.048	0.105	0.333	5.99	0.867	125	4,800	1%
NHTU2CHT	SNHTU2-1	Naphtha Hydrotreater CHG HTR	0.3.8	0.22	0.70	0.022	0.096	0.048	0.208	0.034	0.075	0.238	4.28	0.619	125	3,492	1%
NHTU2STRP	SNHTU2-2	Naphtha Hydrotreater Stripper Reboiler	12.0.1	0.42	1.31	0.041	0.180	0.089	0.392	0.065	0.142	0.447	8.05	1.166	125	6,575	1%
NHTU2SP1T	SNHTU2-3	Naphtha Hydrotreater Stripper Reboiler	13.1.1	0.57	2.09	0.065	0.287	0.142	0.624	0.103	0.226	0.712	12.81	1.855	125	10,464	1%

Table A-4: Estimate of HCU2 Expansion Fugitive Emission Increases from Piping Components

Component Type	Stream Type	Current Emissions		After Expansion		Increase/Change Only	
		Emission Factor	Area Name >> FHCU2	FHCU2	Increases to other Misc. CEP	FHCU2	Increases to other Misc. CEP
			FIN >> HCU NO2 FE	HCU NO2 FE		HCU NO2 FE	
			Number of Components	Number of Components	Number of Components	Number of Components	Number of Components
Valves	Gas/Vapor	0.059	3,306	3,471	82	165	82
	Light Liquid	0.024	428	449	60	21	60
	Heavy Liquid	0.00051	1,953	2,051	60	98	60
Leakless Valves	Gas/Vapor	0.059					
	Light Liquid	0.024					
	Heavy Liquid	0.00051					
Pumps	Light Liquid	0.251	7	7	1	0	1
	Heavy Liquid	0.046	6	6	1	0	1
Flanges	All Streams	0.00055	8,063	8,466	597	403	597
	Light Liquid	0.00055					
	Heavy Liquid	0.00055					
Compressors	Gas/Vapor	1.399	6	6	0	0	0
Relief Valves	Gas/Vapor	0.35	41	43	3	2	3
Open Ends		0.0051					
Sample Con.		0.033					
Other	Gas/Vapor	0					
	Lv/Hvy Liquid	0					
Process Drains		0.07	123	129	0	6	
Total Components			13,933	14,630	804	697	804
			Control Efficiency	Control Efficiency	Control Efficiency		
Valves	Gas/Vapor		98.72%	98.72%	98.72%		
	Light Liquid		98.87%	98.87%	98.87%		
	Heavy Liquid		97.00%	97.00%	97.00%		
Leakless Valves	Gas/Vapor		100.00%	100.00%	100.00%		
	Light Liquid		100.00%	100.00%	100.00%		
	Heavy Liquid		100.00%	100.00%	100.00%		
Pumps	Light Liquid		100.00%	100.00%	100.00%		
	Heavy Liquid		100.00%	100.00%	100.00%		
Flanges	All Streams		97.00%	97.00%	97.00%		
	Light Liquid		97.00%	97.00%	97.00%		
	Heavy Liquid		97.00%	97.00%	97.00%		
Compressors	Gas/Vapor		98.20%	98.20%	98.20%		
Relief Valves	Gas/Vapor		100.00%	100.00%	100.00%		
Open Ends			97.00%	97.00%	97.00%		
Sample Con.			97.00%	97.00%	97.00%		
Other	Gas/Vapor		0.00%	0.00%	0.00%		
	Lv/Hvy Liquid		0.00%	0.00%	0.00%		
Process Drains			98.89%	98.89%	98.89%		

Table A-4: Estimate of HCU2 Expansion Fugitive Emission Increases from Piping Components

			Hourly Emissions (lb/hr)	Hourly Emissions (lb/hr)	Hourly Emissions (lb/hr)	Increase/Change Only		
Component Type	Stream Type					Hourly Emissions (lb/hr)	Hourly Emissions (lb/hr)	
Valves	Gas/Vapor		2.4967	2.6215	0.0619	0.1248	0.0619	
	Light Liquid		0.1161	0.1219	0.0164	0.0058	0.0164	
	Heavy Liquid		0.0299	0.0314	0.0009	0.0015	0.0009	
Leakless Valves	Gas/Vapor		0.0000	0.0000	0.0000			
	Light Liquid		0.0000	0.0000	0.0000			
	Heavy Liquid		0.0000	0.0000	0.0000			
Pumps	Light Liquid		0.0000	0.0000	0.0000	0.0000	0.0000	
	Heavy Liquid		0.0000	0.0000	0.0000	0.0000	0.0000	
	All Streams		0.1330	0.1397	0.0098	0.0067	0.0098	
Flanges	Light Liquid		0.0000	0.0000	0.0000			
	Heavy Liquid		0.0000	0.0000	0.0000			
	Gas/Vapor		0.1511	0.1586	0.0000	0.0076	0.0000	
Compressors	Gas/Vapor		0.0000	0.0000	0.0000	0.0000	0.0000	
Relief Valves	Gas/Vapor		0.0000	0.0000	0.0000			
Open Ends			0.0000	0.0000	0.0000			
Sample Con.			0.0000	0.0000	0.0000			
Other	Gas/Vapor		0.0000	0.0000	0.0000			
	Li/Hvy Liquid		0.0000	0.0000	0.0000			
Process Drains			0.0956	0.1003	0.0000	0.0048	0.0000	
			Hours	Hours	Hours	Increase/Change Only		
			8,760	8,760	8,760	Annual Emissions (tpy)	Annual Emissions (tpy)	
Valves	Gas/Vapor		10.9355	11.4823	0.2712	0.5468	0.2712	
	Light Liquid		0.5084	0.5338	0.0717	0.0254	0.0717	
	Heavy Liquid		0.1309	0.1374	0.0040	0.0065	0.0040	
Leakless Valves	Gas/Vapor		0.0000	0.0000	0.0000			
	Light Liquid		0.0000	0.0000	0.0000			
	Heavy Liquid		0.0000	0.0000	0.0000			
Pumps	Light Liquid		0.0000	0.0000	0.0000	0.0000	0.0000	
	Heavy Liquid		0.0000	0.0000	0.0000	0.0000	0.0000	
	All Streams		0.5827	0.6118	0.0431	0.0291	0.0431	
Flanges	Light Liquid		0.0000	0.0000	0.0000			
	Heavy Liquid		0.0000	0.0000	0.0000			
	Gas/Vapor		0.6618	0.6949	0.0000	0.0331	0.0000	
Compressors	Gas/Vapor		0.0000	0.0000	0.0000	0.0000	0.0000	
Relief Valves	Gas/Vapor		0.0000	0.0000	0.0000			
Open Ends			0.0000	0.0000	0.0000			
Sample Con.			0.0000	0.0000	0.0000			
Other	Gas/Vapor		0.0000	0.0000	0.0000			
	Li/Hvy Liquid		0.0000	0.0000	0.0000			
Process Drains			0.4186	0.4395	0.0000	0.0209	0.0000	
		Area Name >>	FHCU2	FHCU2	Other CEP	FHCU2	Other CEP	Total Increase
Totals:	Total loss lb/hr		3.0223	3.1735	0.0891	0.1511	0.0891	0.2402
	Total Loss tpy		13.2379	13.8998	0.3901	0.6619	0.3901	1.0520
	% VOC		100.0%	100.0%	100.0%			
	VOC lb/hr		3.0223	3.1735	0.0891	0.1511	0.0891	0.2402
	VOC tpy		13.2379	13.8998	0.3901	0.6619	0.3901	1.0520
	Air Toxics/HAPS							
Totals:	% Benzene		0.01%	0.01%	0.01%			
	Benzene lb/hr		3.02E-04	3.17E-04	0.0000	1.51E-05	8.91E-06	2.40E-05
	Benzene tpy		0.0013	0.0014	0.0000	6.62E-05	3.90E-05	1.05E-04
	% Hydrogen Sulfide (in liq)		0.6%	0.6%	0.6%			
	Hydrogen Sulfide lb/hr		0.0022	0.0024	0.0002	1.12E-04	1.63E-04	2.75E-04
	Hydrogen Sulfide tpy		0.0098	0.0103	0.0007	4.92E-04	7.13E-04	1.21E-03
	% Gasoline (in liq)		99.4%	99.4%	99.4%			
	Gasoline lb/hr		0.3723	0.3909	0.0270	0.0186	0.0270	0.0456
	Gasoline tpy		1.6308	1.7123	0.1182	0.0815	0.1182	0.1997
	% Alkylate (in vapor)		99.8%	99.8%	99.8%			
	Alkylate lb/hr		2.6425	2.7746	0.0618	0.1321	0.0618	0.1939
	Alkylate tpy		11.5741	12.1528	0.2707	0.5787	0.2707	0.8494
	% Hexane (in vapor)		20.0%	20.0%	20.0%			
	Hexane lb/hr		0.5296	0.5560	0.0124	0.0265	0.0124	0.0389
Hexane tpy		2.3195	2.4354	0.0542	0.1160	0.0542	0.1702	
Greenhouse Gases								
% Methane (in vapor)		50.0%	50.0%	50.0%				
Methane lb/hr		1.3239	1.5867	0.0443	0.263	0.045	0.307	
Methane tpy		5.7986	6.9499	0.1951	1.15	0.20	1.346	
Methane as CO2e, tpy (GWP of 25)		145.0	173.7	4.9	28.8	4.9	33.7	

* Pumps with double mechanical seal and using barrier fluid seal pot sent to a control device are considered 100% controlled.

** See specific streams in 2013 PAR Fugitives updated.xlsx for percentages.

Table A-5: HCU2 Expansion Project Product Tank Emission Increases

Product Tank Throughput Increase

The HCU2 Modification project is expected to result in an increase in diesel and naphtha production. Emissions from product storage tanks would be expected to increase as a result of increased throughput. The emissions increase related to this throughput increase were estimated by identifying the tank with the highest representative emissions per throughput, and assuming that the additional throughput from this project is routed through the tank with the highest emissions per throughput.

	bbis/yr	KB/D
Low Cetane	2,701,000	7.4
High Cetane	11,899,000	32.6
Light Naphtha	1,971,000	5.4
Heavy Naphtha	3,285,000	9
Total Product Increase		54.4

Emission Increase Calculation

FIN #	Tank No	Product	Incremental Throughput gal/yr	Emission factor tons VOC/gal	VOC Emission Increase tons/yr
	1553	Light Naphtha	82,782,000	6.74E-10	0.06
	1671	Heavy Naphtha	137,970,000	8.36E-10	0.12
	1712	Low Cetane Diesel	113,442,000	1.54E-08	1.75
	1679	High Cetane Diesel	499,758,000	3.59E-09	1.79

Screening Evaluation of which diesel tank would result in the highest emissions per unit throughput

Emissions shown are from annual FER reports

FIN#	Tank No.	Product	Permit No.	Limit (tpy)	Historic Throughput		Thruput if project increase of that product goes to just one tank.		Emission factor tons/gal
					Throughput gal/yr	Emissions tons/yr	Throughput gal/yr	Emissions tons/yr	
	1553	Light Naphtha	8404	5.21	122,707,589	4.45	205,489,589	4.50	6.74E-10
	1601	Light Naphtha	8404	5.28	104,431,095	4.45	187,213,095	4.50	6.74E-10
	1671	Heavy Naphtha	8404	2.55	57,125,205	0.62	195,095,205	0.73	8.36E-10
	2145*	Heavy Naphtha	6056	4.17	57,125,205	1.17	195,095,205	1.28	7.86E-10
	1712	Low Cetane ULSD	8404	4.04	15,959,471	0.32	129,401,471	2.07	1.54E-08
	2094	Low Cetane ULSD	6056	6.32	262,393,752	3.38	375,835,752	3.70	2.84E-09
	1679	High Cetane ULSD	8404	4.37	92,364,981	1.63	592,122,981	3.42	3.59E-09
	1775	High Cetane ULSD	8404	4.14	20,391,105	0.03	520,149,105	0.54	1.02E-09

Table A-6: Tail Gas Incinerator Emissions Impact of Incremental Sulfur Production Rate from HCU2 Expansion

HCU2 Expansion Increased Sulfur Load (SBU2)

105 LTPD of Sulfur Production

Emissions SBU2 (CEP plant)

Component	Emission Basis	Emission Factor	Emission Factor Units	Hourly Emission (lb/hr)	Average Annual Emission (Tons/yr)
CO2	(7)	36.46	lbs/hr per LTPD	3828	16,767
NOx	(1)	0.01338	lbs/hr per LTPD	1.40	6.15
CO	(2)	0.03191	lbs/hr per LTPD	3.35	14.68
SO2	(3)	0.18234	lbs/hr per LTPD	19.15	83.86
TRS (as H2S)	(4)	0.00194	lbs/hr per LTPD	0.20	0.89
VOC	(4), (6)	0.00090	lbs/hr per LTPD	0.09	0.41
Particulate	(5), (6)	0.00125	lbs/hr per LTPD	0.13	0.57
H2SO4	(8)	1.00%	% SO2 Converted		1.3

HCU2 Expansion Increased Sulfur Load (SBU1):

6 LTPD of Sulfur Production

Emissions SBU1 (Base plant)

Component	Emission Basis	Emission Factor	Emission Factor Units	Hourly Emission (lb/hr)	Average Annual Emission (Tons/yr)
CO2	(7)	36.46	lbs/hr per LTPD	219	958
NOx	(1)	0.01563	lbs/hr per LTPD	0.09	0.41
CO	(2)	0.03123	lbs/hr per LTPD	0.19	0.82
SO2	(3)	0.17845	lbs/hr per LTPD	1.07	4.69
TRS (as H2S)	(4)	0.00190	lbs/hr per LTPD	0.01	0.05
VOC	(4), (6)	0.00105	lbs/hr per LTPD	0.01	0.03
Particulate	(5), (6)	0.00146	lbs/hr per LTPD	0.01	0.04
H2SO4	(8)	1.00%	% SO2 Converted		0.1

NOTES:

- (1) 0.08 lb NOx/MMBtu HHV based on Maximum Incinerator Burner Heat Release of 75.0 MMBTU-HHV/hr
- (2) 100 ppmv, dry and zero excess air
- (3) 250 ppmv, dry and zero excess air (NSPS Subpart J is 250 ppmv)
- (4) Total reduced sulfur compounds (TRS calculated as H2S) are estimated as 5 ppmvd.
- (4) Incinerator Burner Emission Factor =

$$5.5 \text{ lb VOC/MMscf of natural gas} * (1,011 \text{ BTU-HHV/ fuel gas scf}) / (1020 \text{ BTU-HHV/n.g.scf}) = 5.45 \text{ lb VOC/MMscf}$$
- (5) Incinerator Burner Emission Factor =

$$7.6 \text{ lb PM/MMscf of natural gas} * (1,011 \text{ BTU-HHV/ fuel gas scf}) / (1020 \text{ BTU-HHV/n.g.scf}) = 7.54 \text{ lb PM/MMscf}$$
- (6) VOC and PM emission factors are from AP-42 Table 1.4-2, July 1998.
- (7) Typical refinery SRU value (need to verify/update consistent with Motiva actual data)
- (8) Factor derived from 2012 TRI

Table A-7: Emissions Impact of Incremental Steam Production Needed for the HCU2 Expansion

HCU2 Expansion Increased Firing Rate for Steam Production:

86 MMBtu/hr

Emissions Assumed to be from Power Station 4

Component	Emission Basis	Emission Factor	Emission Factor Units	Hourly Emission (lb/hr)	Average Annual Emission (Tons/yr)
CO2	(7)	122.00	lb/ MMBtu	10492	45,955
NOx	(1)	0.01817	lb/ MMBtu	1.56	6.85
CO	(2)	0.03319	lb/ MMBtu	2.85	12.50
SO2 (short-term)	(3)	0.03111	lb/ MMBtu	2.68	
SO2 (long-term)	(3)	0.02333	lb/ MMBtu		8.79
H2SO4	(8)	19%	% SO2 Converted	0.76	2.50
VOC	(4)	0.00506	lb/ MMBtu	0.43	1.90
Particulate (Front half)	(5)	0.010	lb/ MMBtu	0.86	3.77
Particulate (back half)	(6)	0.019	lb/ MMBtu	1.63	7.12
Total Particulate (PM10/PM2.5)				2.5	10.9

NOTES:

- (1) 5 ppmvd, dry and zero excess air
- (2) 15 ppmv, dry and zero excess air
- (3) short-term: 5 gr S/ 100 dscf fuel (2 lb SO2/7000 gr S) - turbine and 160 ppmv dry, and excess zero (NSPS Subpart J) for duct burner long-term: 0.25 gr S/ 100 dscf fuel - turbine and 120 ppmv dry and excess zero for duct burner
- (4) 4 ppmvd, dry and zero excess air (assuming methane)
- (5) Vendor Guarantee for the Turbine - 7.04 lb/hr PM; Duct burner 0.01 lb/MMBtu
- (6) Front-Half Emissions + emissions of (NH₄)₂SO₄ [assume 50% of SO₃ converts to (NH₄)₂SO₄]
- (7) Typical Refinery fuel gas value for lb CO2/MMBtu (note: NG is 120 lb/MMBtu)
- (8) Factor derived from the average conversion of SO2 to H2SO4 from May & June 2012 Stack Test w/SCR

(See PWS4 Emissions (Cogen Calcs Tab) in Draft Emissions Folder for Back-up)

Table A-8: Emissions Impact of Incremental Cooling Water Needed for the HCU2 Expansion

The HCU2 Modification project is expected to result in an increase in cooling water. Emissions from cooling towers would be expected to increase as a result of the predicted increased cooling water rate. The emissions increase related to this increase were estimated by identifying the cooling tower that is most likely to be affected, and assuming that the additional cooling water needed for the HCU2 expansion is routed through that cooling tower.

HCU2 Expansion Increased Cooling Water Rate

2508 MMBtu/hr

Emissions from CRU5 FE (Cooling Tower)

Component	Emission Basis	Emission Factor	Emission Factor Units	Hourly Emission (lb/hr)	Average Annual Emission (Tons/yr)
PM	(1)	9.86E-05	ton/ gpm	0.056	0.25
PM10	(1)	8.68E-05	ton/ gpm	0.050	0.22
PM2.5	(1)	5.07E-07	ton/ gpm	2.90E-04	1.27E-03
VOC	(2)	1.84E-04	ton/ gpm	0.105	0.46
Chlorine	(3)	2.27E-05	ton/ gpm	0.013	0.06
Benzene	(4)	5.52E-07	ton/ gpm	3.16E-04	1.38E-03

NOTES:

- (1) Based on Engineering Assessment of Liquid drft of 0.005% and Annual average TDS of 900 ppm, PM10/2.5 speciation from original CEP permitting.
- (2) VOC emissions factor from AP-42 Table 5.1-2 (Jan 1995) for control by monitoring.
- (3) Based on maximum estimated concentration of 0.5 mg/L chlorine in cooling water
- (4) Based on 0.30% Benzene weight percent of total VOC emissions

Appendix B: TCEQ Form PI-1
(Copy of form submitted to TCEQ with
Criteria Pollutant PSD Application)



**Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment**

Important Note: The agency requires that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued and no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: Motiva Enterprises LLC		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: Mr. Greg Willms		
Title: General Manager		
Mailing Address: P.O. Box 712		
City: Port Arthur	State: Texas	ZIP Code: 77641-0712
Telephone No.: (409) 989-7001	Fax No.: (409) 989-7774	E-mail Address: Greg.Willms@motivaent.com
C. Technical Contact Name: Laurie Carpenter		
Title: Environmental Specialist		
Company Name: Motiva Enterprises LLC		
Mailing Address: P.O. Box 712		
City: Port Arthur	State: Texas	ZIP Code: 77641-0712
Telephone No.: (409) 989-7449	Fax No.: (409) 989-7108	E-mail Address: laurie-sue.carpenter@motivaent.com
D. Site Name: Port Arthur Refinery		
E. Area Name/Type of Facility: Crude Expansion Project		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Petroleum Refining		
Principal Standard Industrial Classification Code (SIC): 2911		
Principal North American Industry Classification System (NAICS): 324110		
G. Projected Start of Construction Date: Approximately April 2015		
Projected Start of Operation Date: TBD		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 2555 Savannah Avenue		
City/Town: Port Arthur	County: Jefferson	ZIP Code: 77640-3399
Latitude (nearest second): 29.88364		Longitude (nearest second): -93.96438



Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility): JE-0095-D	
J. Core Data Form.	
Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).	☐ YES ☒ NO
K. Customer Reference Number (CN): 600124051	
L. Regulated Entity Number (RN): 100209451	
II. General Information	
A. Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES ☒ NO
B. Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C. Number of New Jobs: 0	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Joan Huffman	District No.: 17
State Representative: Joe Deshotel	District No.: 22
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested.	
☐ Initial ☒ Amendment ☐ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation	
B. Permit Number (if existing): 6056	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. <i>(check all that apply, skip for change of location)</i>	
☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit ☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source ☐ Other:	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO



**Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment**

III. Type of Permit Action Requested (continued)		
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0		☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City/Town:	County:	ZIP Code:
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information.		☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?		☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.		
List: NONE		
G. Are you permitting planned maintenance, startup, and shutdown emissions? If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.		☐ YES ☒ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) Is this facility located at a site required to obtain a federal operating permit? If Yes, list all associated permit number(s), attach pages as needed).		☒ YES ☐ NO ☐ To be determined
Associated Permit No (s.): 1386, 3387		
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.		
☐ FOP Significant Revision ☐ FOP Minor ☐ Application for an FOP Revision ☐ Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☒ To be Determined ☐ None		



Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

III. Type of Permit Action Requested (continued)

H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) (continued)

2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. *check all that apply*

- | | |
|--|---|
| ☐ GOP Issued | ☐ GOP application/revision application submitted or under APD review |
| ☒ SOP Issued | ☐ SOP application/revision application submitted or under APD review |

IV. Public Notice Applicability

- | | |
|---|---|
| A. Is this a new permit application or a change of location application? | ☐ YES ☒ NO |
| B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2. | ☐ YES ☒ NO |
| C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit? | ☒ YES ☐ NO |
| D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area? | ☐ YES ☒ NO |

If Yes, list the affected state(s) and/or Class I Area(s).

List:

E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.

- | | |
|---|---|
| 1. Is there any change in character of emissions in this application? | ☐ YES ☒ NO |
| 2. Is there a new air contaminant in this application? | ☐ YES ☒ NO |
| 3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)? | ☐ YES ☒ NO |

F. List the total annual emission increases associated with the application
Note: The below emissions show only those emissions that will increase versus current allowable levels. Increased actual emissions for some upstream and downstream unmodified sources have been quantified for PSD applicability and PSD air analysis purposes, but do not represent increases to allowable. For these other project emissions see later application reference Section PI-1 Section IV and Appendix A.

Volatile Organic Compounds (VOC): Increase to allowable of 1.05 tons/yr VOC

Sulfur Dioxide (SO₂):

Carbon Monoxide (CO):

Nitrogen Oxides (NO_x):

Particulate Matter (PM):

PM 10 microns or less (PM₁₀):

PM 2.5 microns or less (PM_{2.5}):

Lead (Pb):

Hazardous Air Pollutants (HAPs): Increase to allowable of 0.0001 tons/yr Benzene

Other speciated air contaminants not listed above: For Air Toxic Review: H₂S, Gasoline, Alkylate, Hexane, (and Benzene)



**Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment**

V. Public Notice Information <i>(complete if applicable)</i>		
A. Public Notice Contact Name: Damian Fryoux		
Title: Manager, Technical		
Mailing Address: P.O. Box 712		
City: Port Arthur	State: Texas	ZIP Code: 77641-0712
B. Name of the Public Place: TCEQ Regional Office		
Physical Address <i>(No P.O. Boxes)</i> : 3870 Eastex Fwy		
City: Beaumont	County: Jefferson	ZIP Code: 77703
The public place has granted authorization to place the application for public viewing and copying.		☒ YES ☐ NO
The public place has internet access available for the public.		☒ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable:		
Mailing Address:		
City:	State:	ZIP Code:
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? <i>(For Concrete Batch Plants)</i>		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Chief Executive:		
Mailing Address:		
City:	State:	ZIP Code:
Name of the Indian Governing Body:		
Mailing Address:		
City:	State:	ZIP Code:



Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

V. Public Notice Information <i>(complete if applicable) (continued)</i>	
C. Concrete Batch Plants, PSD, and Nonattainment Permits	
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. <i>(continued)</i>	
Name of the Federal Land Manager(s):	
D. Bilingual Notice	
Is a bilingual program required by the Texas Education Code in the School District?	☒ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?	☒ YES ☐ NO
If Yes, list which languages are required by the bilingual program?	Spanish
VI. Small Business Classification <i>(Required)</i>	
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than \$6 million in annual gross receipts?	☐ YES ☒ NO
B. Is the site a major stationary source for federal air quality permitting?	☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☒ YES ☐ NO
VII. Technical Information	
A. The following information must be submitted with your Form PI-1 <i>(this is just a checklist to make sure you have included everything)</i>	
1. ☒ Current Area Map	
2. ☒ Plot Plan	
3. ☒ Existing Authorizations	
4. ☒ Process Flow Diagram	
5. ☒ Process Description	
6. ☒ Maximum Emissions Data and Calculations	
7. ☒ Air Permit Application Tables	
a. ☒ Table 1(a) (Form 10153) entitled, Emission Point Summary	
b. ☒ Table 2 (Form 10155) entitled, Material Balance	
c. ☐ Other equipment, process or control device tables	
B. Are any schools located within 3,000 feet of this facility?	☒ YES ☐ NO



**Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment**

VII. Technical Information			
C. Maximum Operating Schedule:			
Hour(s): 24	Day(s): 7	Week(s): 52	Year(s):
Seasonal Operation? If Yes, please describe in the space provide below.			☐ YES ☒ NO
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☒ YES ☐ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.			
Year 2010 – Pump, fugitive, compressor, heat exchanger and vessel repair/replacement, Chemicals and Cleaners, Vacuum Trucks and Frac Tanks, painting and blasting, portable control devices and controlled recovery systems.			
E. Does this application involve any air contaminants for which a disaster review is required?			☐ YES ☒ NO
F. Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)? Benzene (TCEQ has proposed removal from the APWL)			☒ YES ☐ NO
VIII. State Regulatory Requirements Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment. The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.			
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			☒ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?			☒ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?			☒ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?			☒ YES ☐ NO
IX. Federal Regulatory Requirements Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment. The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.			
A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?			☒ YES ☐ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?			☒ YES ☐ NO



Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

IX. Federal Regulatory Requirements Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment. The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.											
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO										
D. Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO										
E. Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO										
F. Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO										
G. Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO										
X. Professional Engineer (P.E.) Seal Is the estimated capital cost of the project greater than \$2 million dollars? ☒ YES ☐ NO If Yes, submit the application under the seal of a Texas licensed P.E.											
XI. Permit Fee Information <table style="width: 100%; border: none;"> <tr> <td style="width: 60%; border: none;">Check, Money Order, Transaction Number ,ePay Voucher Number:</td> <td style="width: 40%; border: none;">Fee Amount: \$75,000</td> </tr> <tr> <td style="border: none;">Paid online?</td> <td style="border: none; text-align: right;">☐ YES ☒ NO</td> </tr> <tr> <td colspan="2" style="border: none;">Company name on check: MOTIVA ENTERPRISES LLC</td> </tr> <tr> <td style="border: none;">Is a copy of the check or money order attached to the original submittal of this application?</td> <td style="border: none; text-align: right;">☒ YES ☐ NO ☐ N/A</td> </tr> <tr> <td style="border: none;">Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?</td> <td style="border: none; text-align: right;">☒ YES ☐ NO ☐ N/A</td> </tr> </table>		Check, Money Order, Transaction Number ,ePay Voucher Number:	Fee Amount: \$75,000	Paid online?	☐ YES ☒ NO	Company name on check: MOTIVA ENTERPRISES LLC		Is a copy of the check or money order attached to the original submittal of this application?	☒ YES ☐ NO ☐ N/A	Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☒ YES ☐ NO ☐ N/A
Check, Money Order, Transaction Number ,ePay Voucher Number:	Fee Amount: \$75,000										
Paid online?	☐ YES ☒ NO										
Company name on check: MOTIVA ENTERPRISES LLC											
Is a copy of the check or money order attached to the original submittal of this application?	☒ YES ☐ NO ☐ N/A										
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☒ YES ☐ NO ☐ N/A										



**Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment**

XII. Delinquent Fees and Penalties

This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at:
www.tceq.texas.gov/agency/delin/index.html

XIII. Signature

The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA. I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.

Name: **Greg Willms**

Signature: _____

Original Signature Required

Date: ~~XX~~

FEB. 26/2014

Appendix C: Separate Source Evaluation

Appendix C

Separate Source Evaluation for Hydrogen Production Emissions

Motiva's expansion of the HCU2/DHT operation will require that Motiva purchase additional hydrogen (H₂) for use by this expanded unit. Engineering estimates of the increased H₂ demand suggest a maximum need of about 80 MMSCF/D of additional H₂. There are currently multiple outside industrial gas suppliers that service Motiva's H₂ needs (as well as the needs of other regional petroleum and chemical facilities). Hydrogen is a readily available commodity in this industrial area. Motiva generates a modest base-load of internally produced hydrogen as a byproduct of other refining processes, but purchases the majority of its H₂ existing needs from three Gulf Coast regional hydrogen suppliers (Praxair, Air Liquide and Air Products). Currently, Motiva purchases about 260 MMSCF/D from these outside suppliers, collectively. The increased H₂ demand resulting from this project will all need to be provided by these, or other, outside suppliers.

Some or all of the incremental H₂ need can be accommodated within the existing capacity of these outside "3rd party" suppliers. It is also possible that one of these suppliers will build a new hydrogen production unit to meet the overall increased demand of the Gulf Coast region. But regardless of the exact scenario, any increased emissions from the production of extra hydrogen would occur at a separate facility/source, not under Motiva's common control, and any associated emissions would be considered "secondary emissions" for this project. The following sections discuss the regulatory language and guidance on how to consider these H₂ production related emissions.

Rules/Guidance:

Secondary emissions are emissions which, although associated with a source, are not emitted from the source itself. Secondary emissions occur from any facility that is not part of the source being modified, but which would not increase except as a result of the modification at the source undergoing permitting. Secondary emissions are not considered in the emissions accounting procedure for PSD applicability determination.ⁱⁱⁱ

Any emissions associated with a nearby 3rd party H₂ production facility would be considered "secondary emissions" for the purposes of this Motiva project unless that 3rd party facility were considered part of the same "source" as the Motiva facility. NSR rules define a source as "any building, structure, facility or installation which emits or may emit any air pollutant subject to regulation under the Act" and further defines "building, structure, facility or installation" as "all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control)." (40 CFR Part 52.21(b)(5) and (6))

Thus, a determination of whether two facilities (i.e.: Motiva and a H₂ vendor) are to be considered a single "source" for NSR purposes depends on the three criteria in the above definition. All three criteria must be met for two facilities to be considered a single source. The three criteria are as follows:

1. The two facilities must both be in a single major industrial grouping (the same two-digit SIC code);

2. They must be located on one or more contiguous or adjacent properties; and
3. They must be under common control of the same person (or persons under common control).

If even one of these criteria is not met, then the two facilities would be considered separate sources for NSR purposes. Setting aside the first two criteria (industrial grouping and adjacent), Motiva believes the most definitive issue in this case is the third criterion – common control. Unless an affected H₂ vendor is considered under the common control of Motiva, then the two facilities are not considered a single source. The following analysis explores this issue.

Analysis

The question of “common control” usually depends on how the facilities interact – and whether, as a practical matter, one has the power, direct or indirect, to direct the management and policies of the other. The following are a list of issues commonly evaluated for this issue along with the specific details on each issue regarding Motiva and the regional H₂ vendors.

- **Common Ownership:** Motiva does not share any common ownership with any of the regional H₂ vendors. Motiva is an independent company, not sharing any common ownership with any of the regional H₂ vendor companies. The only connection between Motiva and each of these firms is a supply service contract negotiated at arm’s length that does not provide any ownership interest in any of the corporations involved to any of the others.
- **Management Decisions:** Each H₂ vendor’s operations are conducted by its own employees, with its own equipment, under its own permits, and in compliance with its own corporate directions and policies.
- **Staff/Function Overlap:** The vendors and Motiva do not share with common workforces, plant managers, security forces, corporate executive officers, or board of executives. Neither do they share common payroll activities, employee benefits, health plans, retirement funds, insurance coverage, or other administrative functions?
- **Degree of Control:** Motiva and the regional H₂ vendors do not depend solely on each other. Each vendor supplies to multiple customers and Motiva purchases from multiple suppliers. Further, each of the facilities can run independently of each other (with the exception that currently the adjacent Praxair facility is physically reliant on Motiva for treated water supply – but they are free to pursue other sources of water). There are no contractual or practical limits on any company pursuing other business interests or customers.
- **Compliance Responsibility:** Motiva and the regional H₂ vendors are each separately responsible for their own compliance with air quality control requirements and for violations of the requirements. There is no shared pollution control equipment. There is no shared responsibility or decision-making regarding compliance or pollution controls.

- **Shared Streams/Byproducts:** Other than the H₂ supply relationship, the adjacent Praxair H₂ plant shares a few minor streams/byproducts with Motiva. Specifically, Praxair purchases their treated water from Motiva, and Motiva handles their waste water. Additionally, Motiva purchases steam from Praxair. These are minor interrelationships. Praxair has their own natural gas supply (used as feedstock and fuel) and their own electricity supply. None of the other regional H₂ plants share any streams or byproducts with Motiva (besides H₂ supply).
- **Onsite Necessity:** It is not necessary for any of the H₂ vendors to be on site –or even close to the Motiva facility. Praxair has one plant co-located with Motiva, but that facility is connected to Praxair’s 300 mile Gulf Coast H₂ pipeline connecting over 750 million scf/d of hydrogen plant capacity and a 2.5 billion scf hydrogen storage cavern. Motiva’s other regional H₂ suppliers are miles away from Motiva and also connected into a delivery pipeline. The ease of pipeline transport illustrates that it is not necessary for H₂ suppliers to be on-site. In this heavily industrialized area, there are multiple customers for H₂, multiple suppliers of H₂, and a robust H₂ supply pipeline network and market. H₂ is a commodity. Even if Motiva were to no longer operate, these H₂ vendors would have other customers.

Summary of Determination:

The above factors support a finding of no common control. There is clearly no common ownership, no shared management, no staff overlap, and no shared compliance responsibilities. Although Motiva purchases the commodity H₂ from vendor companies, Motiva is just one of their regional customers, and they are not solely dependent on Motiva, nor is Motiva solely dependent on any of the individual vendors. Each could exist and operate without the other. Specific to the Praxair facility, in addition to H₂ supply, there is a minor additional interaction in that Motiva supplies water and wastewater treatment and purchases steam. But these are not major relationships, and Praxair is free to pursue other sources for these support functions or other customers for its byproduct steam. Taken together, the facts in this case do not indicate that Motiva and the H₂ vendors operate as a single facility or that they are under the control of the same persons. If there is no “common control”, then irrespective of the other “source” criteria, these facilities should be considered separate sources.

As a separate point, irrespective of the common control question discussed above, a single source finding can’t be made if two facilities are not “contiguous or adjacent”. Contiguous means to have contact with in unbroken sequence. Except for Praxair, the other regional H₂ vendors are not contiguous. EPA has historically interpreted “adjacent” as meaning “nearby”. Separation by a road, river, or other right-of-way is typically not enough to not be considered adjacent. However, the regional H₂ vendors located at miles away are arguable too distant to be considered “adjacent” to Motiva. In particular, given that they are owned and operated by separate companies, are several miles away from Motiva, and serve other customers besides Motiva, it would be inappropriate to consider them a single source with Motiva. To do so would defy the common-sense notion of a plant or facility within the ordinary meaning of “building”, “structure”, “facility” or “installation” in the NSR definitions discussed previously.

ⁱ Ibid, page 20 of 51.

ⁱⁱ http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_fugitives.pdf

ⁱⁱⁱ US EPA “New Source Review Workshop Manual”, Draft, October 1990. Page A-16.