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UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY
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DIVISION OF AIR QUALITY

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Mr. Martin D. Gray Manager
Utah Air Quality Board
P.O. Box 144820
195 North 1950 West
Salt Lake City, UT 84114-4820
Attn: John Jenks

Subject: Response to SIP PM2.5 BACT Analysis Request

Dear Mr. Gray,

Chevron Products Company (Chevron) Salt Lake Refinery is providing the attached in response to the request for BACT information by Utah Department of Air Quality (UDAQ). Specifically, the attached provides a Best Available Control Technology (BACT) analysis to UDAQ.

Because of the short time frame to prepare this estimate, these cost estimates are not definitive. Retrofitting equipment can produce unforeseen costs that are only determinable by detailed engineering work. Further, all of the cost information included is non-site specific. Any selected technologies would need to be reevaluated for site specific information.

The economic feasibility analyses in the attached are provided for $PM_{2.5}$ as well as for precursors for $PM_{2.5}$ emissions including SO_2, NOx, VOC, and NH_3. It is important to note that emissions of $PM_{2.5}$ precursors do not correlate directly to emissions of $PM_{2.5}$ and thus, the $/ton of $PM_{2.5}$ precursors calculated in the economic feasibility analyses cannot be assumed to translate directly to $PM_{2.5}$ $/ton cost effectiveness.

If you have any questions regarding the attached BACT analysis please contact Kaci Walker at (801) 539-7238.

Sincerely,

Christina King

Christina King
HES Manager

Attachment

Boiler #1 F11001, Boiler #2 F11002, and Boiler #4 F11004 BACT Analysis

1. Site and Company/Owner Name

Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. Description of Facility:

The Salt Lake Refinery processes crude oils and lesser quantities of other hydrocarbon feedstocks to produce transportation fuels, petroleum coke, sulfur, and various byproducts. The refinery operates 24 hours per day and 365 days per year. The nominal capacity of the Salt Lake Refinery is approximately 56,000 barrels of crude oil per calendar day.

The refinery uses three general processes to transform crude oil into refined petroleum products: distillation, conversion, and purification. These processes occur in nine primary process units and various ancillary units. More detailed descriptions of the processes, process equipment, raw materials, and products have been previously submitted by Chevron, in materials such as the operating permit application for the refinery. However, included in this section are general descriptions of the existing Salt Lake Refinery process units.

Crude Unit (Plant #21)

The first major step in the refining process is distillation of crude oil, which separates the different hydrocarbon chains that comprise crude oil. Crude oil is pumped from storage tanks to the unit battery limits and preheated by exchange with hot products. The crude oil then passes through a desalter to remove naturally occurring salts and solids, which could lead to fouling and corrosion of downstream equipment, and is then heated in a gas-fired process heater.

The heated feed is sent to the atmospheric distillation column to separate the crude oil into various hydrocarbon fractions: refinery fuel gas (RFG), liquefied petroleum gas (LPG), naphtha, kerosene, diesel, and atmospheric residuum. Light hydrocarbons (methane, ethane, and propane), gases (hydrogen, hydrogen sulfide, etc.), and naphtha leave the top of the atmospheric distillation column and go to an overhead condenser/separator.

The light gases and hydrocarbons leave the top of the overhead separator and go to the Amine Units for sulfur removal before being used as RFG in the refinery process heaters and boilers. RFG consists of both amine-treated refinery gases and supplemental purchased natural gas. Supplemental purchased natural gas is added to balance the refinery's energy needs.

The condensed hydrocarbons go to the naphtha stabilizer to further remove light hydrocarbons, such as LPG, from the naphtha. Stripping steam condensed in the overhead separator is sent to the Sour Water Stripper Unit. The various straight run hydrocarbon draws (kerosene and diesel) from the side of the atmospheric distillation column go to side strippers and further processing in the refinery.

Atmospheric residuum, withdrawn from the bottom of the atmospheric distillation column, comprises the primary feed to the vacuum distillation column. This material is partially vaporized in a gas-fired charge heater before being distilled under vacuum conditions. Vacuum gas oils are produced as liquid products and are used as feed to the Fluid Catalytic Cracking Unit ("FCCU") and the Coker Unit. Vacuum residuum, which is the remaining liquid fraction that is withdrawn from the bottom of the vacuum distillation column, is the primary feed to the Coker Unit. Stripping and vacuum ejector steam is condensed in the vacuum distillation column overhead system and sent to the Sour Water Stripper Unit.

The crude unit furnaces can fire refinery fuel gas or purchased natural gas.

Coker Unit (Plant #70)

The second major step in crude oil refining at the Salt Lake Refinery is conversion, which converts the heavy unfinished products from the crude unit into lighter products such as gasoline and diesel fuel. This is accomplished primarily in the Delayed Coker (Coker Unit), discussed in this section, and in the FCCU, Reformer Unit, Isomerization Unit, and Alkylation Unit, each of which is discussed later.

The Coker Unit at the Salt Lake Refinery uses the delayed coking process. This is a semicontinuous, thermal cracking process whereby heavy hydrocarbon feedstocks such as FCC heavy cycle oil and vacuum residuum are converted to lighter liquid products and petroleum coke.

The heavy feed streams are first pumped from storage tanks to a fractionator column where they are mixed with the fractionation column bottoms. The combined stream of coker feed and fractionator bottoms is heated in a gas-fired process heater to initiate coke formation in the coke drums. The formation of coke is a thermal cracking process in which the hot coker feed thermally decomposes (*i.e.,* cracks) into hydrocarbon vapors and coke. The hydrocarbon vapors leave the coke drum overhead and flow to the fractionator column. This distillation column separates the cracked hydrocarbons into fuel gas, LPG, naphtha, coker diesel, and coker gas oil.

The Coker Unit at the Salt Lake Refinery employs a pair of coke drums that are alternately switched on- and off-line after filling with hot feed. After coking reactions are complete, the full coke drum is switched off-line and is steamed out and cooled. Vapors are captured by the closed blowdown system and recovered in the fractionator. After quenching/cooling, the coke drum bottom and top heads are opened. The coke is cut from the drum with a high-pressure water jet and dropped into a pit where the free water is separated from the coke and recycled. The only fuel used is refinery fuel gas.

Hydrodenitrification ("HDN") Unit (Plant #71)

The third and final major step in a modern refinery such as the Salt Lake Refinery is purification, where impurities such as sulfur and nitrogen are removed from intermediate streams and/or final products. Purification is required, at a minimum, so that when final products such as gasoline and diesel fuel are consumed they will burn more cleanly. Purification of intermediate streams has the additional benefit of allowing certain refinery process units to operate with lower levels of air emissions. Purification at the Salt Lake Refinery is accomplished primarily in the HDN Unit and the Vacuum Gas Oil ("VGO") Hydrotreater Unit and Hydrodesulfurization ("HDS") Unit, which are discussed later.

The HDN Unit removes sulfur and nitrogen from intermediate Coker Unit product streams such as coker diesel and coker gas oil. This is accomplished by contacting the intermediate feed streams with a hydrotreating catalyst in the presence of hydrogen gas. Sulfur and nitrogen are removed from the HDN Unit feed streams in a hydrotreating reactor to form hydrogen sulfide gas and ammonia gas, which are then routed to the Amine Units and Sour Water Strippers. The HDN Unit uses two gas-fired process heaters. The only fuel used to fire these heaters is refinery fuel gas.

HDS Unit (Plant #64)

The HDS Unit is very similar to the HDN Unit. Instead of processing Coker Unit intermediates, the HDS Unit processes diesel fuel from the Crude Unit. In the HDS reactor, sulfur and nitrogen are removed from the diesel and replaced by hydrogen. Sulfur and nitrogen form hydrogen sulfide gas and ammonia gas, which are then routed to the routed to the Amine Units and Sour Water Strippers. The HDS Unit uses two gas-fired process heaters. The HDS process heaters can be fired on refinery fuel gas or purchased natural gas.

VGO Hydrotreater Unit (Plant #66)

The VGO Hydrotreater Unit removes sulfur and nitrogen from gas oil produced in the Crude Unit prior to being sent as feed to the FCCU. This is accomplished by contacting the gas oil with a hydrotreating catalyst in the presence of hydrogen gas. Sulfur and nitrogen are removed from the gas oil in a hydrotreating reactor to form hydrogen sulfide gas and ammonia gas, which are then routed to the Amine Units and Sour Water Strippers. The VGO Hydrotreater Unit uses two gas-fired process heaters. The only fuel used for these heaters is refinery fuel gas.

FCCU and Gas Recovery Unit ("GRU") (Plants #31 & #32)

The FCCU at the Salt Lake Refinery processes gas oils into gasoline, diesel, and other light products by cracking the heavy molecules in a low pressure reactor. This unit processes primarily gas oils from the Crude Unit and Coker Unit that have been hydrotreated in the VGO Hydrotreater Unit and HDN Unit. The hydrotreated gas oils are first heated in a gas-fired process heater before being fed to the FCCU reactor. The cracking reaction occurs at high temperatures and in an atmosphere of fluidized cracking catalyst. Cracked product is then distilled into various boiling range products in the GRU. Products are routed to additional process units for further treatment and processing. Coke is a byproduct of the reaction and is deposited on the catalyst. The coke is burned in the FCCU catalyst regenerator. Catalyst particles entrained in the combustion products from the regenerator are recovered in cyclones, and an electrostatic precipitator is used for control of particulate matter emissions by removal of remaining catalyst particles. Two furnaces that fire only refinery fuel gas are used in the FCC operations.

Reformer Unit (Plant #35)
The catalytic Reformer Unit changes the molecular size and shape of low-octane gasoline creating a high-octane gasoline blend component. The reforming process includes four catalytic reactor beds. First, a hydrotreating pre-treatment reactor removes low levels of residual sulfur contamination and nitrogen. The three remaining catalytic reactors "reform" hydrocarbons into larger, high-octane molecules for blending into gasoline. Distillation equipment downstream of the reactor section separates the reactor product into various components. The Reformer Unit utilizes three process heaters that are fired with refinery fuel gas and three internal combustion engines that are fired with natural gas.

Isomerization Unit (Plant #37)
The Isomerization Unit converts or "isomerizes" normal butane into isobutane in one of two catalytic reactors. Isobutane is required in the alkylation process. The Isomerization Unit does not contain any fired furnaces.

Alkylation Unit (Plant #36)
The alkylation process reacts isobutane with propylene or butene in the presence of a hydrofluoric acid catalyst. The primary product of this reaction is a high octane product called alkylate. In addition to creating high octane blend components, the Alkylation Unit reduces the vapor pressure of its feed stocks. Butane and propane are produced by the Alkylation Unit. This unit uses one furnace in its operation. Alkylation polymer and refinery fuel gas are used as fuels.

Steam Plant (Plant #11)
The refinery has five boilers that produce steam for the refinery. Natural gas and refinery fuel gas are used as fuels for the boilers.

Amine Units and Sour Water Strippers (Plants #44, #45, #67)
The Amine Units remove hydrogen sulfide from the fuel gas produced in the process units previously described. In the amine process, hydrogen sulfide is contacted with liquid amine and absorbed into a liquid amine solution. The hydrogen sulfide is then stripped from the amine solution and processed by the Sulfur Recovery Plants for recovery of elemental sulfur. Amine is regenerated and recycled within the Amine Units.

The Sour Water Strippers remove ammonia and hydrogen sulfide from sour water generated in the process units described earlier. Using steam, the sour water is stripped of these contaminants in a packed column. The ammonia and hydrogen sulfide components of the sour water are removed for further processing in the Sulfur Recovery Plants.

There are no furnaces in the Sour Water Strippers or Amine Units.

Sulfur Recovery Plants (Plants #65 & #68)
The Sulfur Recovery Plants convert hydrogen sulfide into liquid sulfur and thermally destroy ammonia, forming water vapor and nitrogen. The molten sulfur product is delivered for marketing sales. Residual gas exiting the final reactor/condenser in each plant is sent to an incinerator for final combustion. Natural gas and refinery fuel gas are used as combustion fuels in the Sulfur Recovery Plants.

Wastewater Treatment Plant (Plant #9)
All refinery process wastewater and storm water is treated in the Wastewater Treatment Unit. A series of tanks, oil/water separators, biological treatment disks, and filters comprise this plant.

Refinery Flares (Plants #35, #75)
The Salt Lake Refinery has three flares that serve primarily as safety devices for the destruction of non-routine hydrocarbon releases. The refinery also has a flare gas recovery system, which recovers and compresses process gases from the Coker (#1) and FCC (#2) flares that would otherwise be flared and routes these gases to the Amine Plant for treatment. The only fuels consistently used are natural gas and refinery fuel gas.

Storage Tanks
The Salt Lake Refinery includes approximately 64 storage tanks for crude oil and various intermediate and final products. Crude oil and lighter materials are stored in external floating roof storage tanks; fixed roof storage tanks are used for heavier materials.

Loading Racks
The Salt Lake Refinery includes loading racks for transportation fuels and for molten sulfur.

Cooling Tower
The Salt Lake Refinery includes four cooling water towers for process cooling. No fuels are used.

Emergency Equipment
The Salt Lake Refinery includes eight reciprocating internal combustion engines used for emergency electric generation and emergency liquid pumping purposes. Diesel fuel is the only fuel used.

3. Recent Permitting Actions (if any):

In 2016, Chevron received authorization for the construction of a new gas-fired boiler, which will be designated Boiler #7. In conjunction with the startup of this new boiler, Boilers #1, #2, and #4 will be permanently shut down.

4. Current Emissions (Boiler #1 F11001, Boiler #2 F11002, and Boiler #4 F11004)

For the purposes of this BACT analysis, Chevron has grouped Boilers #1 F11001 (55.8 MMBtu/hr), #2 F11002 (55.8 MMBtu/hr), and #4 F11004 (54.1 MMBtu/hr) together. These boilers have been grouped together for this BACT analysis based on their similar operation and they are of the same design. Chevron has used 2015 emissions from all three boilers in this analysis. Estimated 2015 emissions for all three boilers are presented in the following tables.

Boiler #1 – 2015 Actual Emissions

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
1.4	1.4	0.0	106.3	1.0	0.6

Boiler #2 – 2015 Actual Emissions

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
1.4	1.4	0.0	106.3	1.0	0.6

Boiler #4 – 2015 Actual Emissions

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
0.8	0.8	0.0	45.0	0.6	0.3

5. Emission Information / Discussion

Stack test data were used to estimate NOx emissions for Boiler #1 F11001, Boiler #2 F11002, and Boiler #4 F11004. All other emissions were calculated as follows:

- VOC, PM10 and PM2.5 – Emission factors from AP-42 Table 1.4.2.
- NH_3 – Development and Selection of Ammonia Emission Factors, August 1994, Table 7.4.
- SO_2 – Based on refinery fuel gas HHV (2015 Emission Inventory) and total sulfur in fuel gas.

Chevron plans to decommission Boiler #1 F11001, Boiler #2 F11002, and Boiler #4 F11004 in 2018. Since the boilers are near the end of life, it is not anticipated that any new add-on controls would be appropriate, and no BACT analysis has been conducted for these sources.

These boilers will be replaced with Boiler #7. Chevron received the air permit for Boiler #7 in 2016. The permit included a BACT analysis for the new source, and since the permit to construct is currently active, the BACT analysis conducted for the permit includes the most up-to-date analysis of available control technologies for this source. Accordingly, a new BACT analysis for Boiler #7 has not been conducted.

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Boiler #5 F11005 and Boiler #6 F11006 BACT Analysis

1. Site and Company/Owner Name

Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. Description of Facility:

Please reference Boiler 1 F11001, Boiler 2 F11002, and Boiler 4 F11004 BACT analysis for a full description of the facility.

3. Recent Permitting Actions (if any):

Boiler #7 F11007 is currently being constructed. BACT was determined to be Low NOx burners and flue gas recirculation. Boiler #6 F11006 and Boiler #5 have identical controls to Boiler #7.

4. Current Emissions (Boiler #5 F11005 and Boiler #6 F11006)

For the purposes of this BACT analysis, Chevron has grouped Boiler #5 F11005 (171.0 MMBtu/hr) and Boiler #6 F11006 (171.0 MMBtu/hr) together. These boilers have been grouped together for this BACT analysis based on their similar operation and they are of the same design. Chevron has used actual 2015 emissions from both boilers in this analysis. Estimated emissions for both boilers are presented in the following tables.

Boiler #5 – 2015 Emissions

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
1.5	1.5	0.01	9.6	1.1	0.6

Boiler #6– 2015 Emissions

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
1.9	1.9	0.01	12.2	1.3	0.8

5. Emission Information / Discussion

Actual emissions for Boiler #5 F11005 and Boiler #6 F11006 were calculated using the actual 2015 fuel consumption and operating schedule for each boiler, as reported in the 2015 Air Emissions Inventory. All other emissions were calculated as follows:

- NOx –Emissions factors from AP-42 Table 1.4.1, adjusted based on the use of Low-NOx burners with flue gas recirculation.
- VOC, PM_{10} and $PM_{2.5}$ – Emission factors from AP-42 Table 1.4.2.
- NH_3 – Development and Selection of Ammonia Emission Factors, August 1994, Table 7.4.
- SO_2 – Based on 1228 Btu/SCF refinery fuel gas HHV (2015 Emission Inventory) and total sulfur in fuel gas.

$PM_{10}/PM_{2.5}$ BACT Options (Boiler #5 F11005 and Boiler #6 F11006)

Option 1: Proper Burner Design and Operation

Description of Option 1: Proper design of burner and firebox components in the boilers will provide the proper air-to-fuel ratio, residence time, temperature, and combustion zone turbulence essential to maintain low PM emission levels. Additionally, effective combustion controls avoid fuel-rich conditions that may promote soot formation. Good combustion efficiency relies on both hardware design and operating procedures. Air and fuel flow rates should be limited to vendor specifications to achieve satisfactory fuel efficiency and emission performance.

Option 2: Post Combustion Particulate Matter Control – Wet Gas Scrubber or Electrostatic Precipitator (ESP)

Description of Option 2: The use of a wet gas scrubber involves a water spray introduced into the boiler exhaust stream, resulting in the cooling and condensing of organic material. The water vapor condenses onto the organic aerosol which then becomes large enough to settle or be removed by cyclonic collectors, filters, or mist eliminators. Wet scrubbers typically obtain an efficiency rate comparable to ESPs of 95% or greater.

ESPs use an electrostatic field to charge particulate matter contained in the gas stream. These charged particles then migrate to a grounded collecting surface. The surface is vibrated or rapped periodically to dislodge the particles, and the particles are then collected in a hopper in the bottom of the unit. The control efficiency for ESPs can range from at least 70 to 93 % removal efficiency.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Proper Burner Design and Operation – Technically Feasible
Chevron currently combusts only fuel gas or natural gas in their refinery boilers and utilizes good combustion practices. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for process gas fired boilers revealed that proper burner design and operation is considered BACT for these emission sources.

Option 2: Post Combustion Particulate Matter Control – Technically Infeasible
A review of the EPA's RBLC database for process gas fired boilers revealed that refinery sources listed did not use any post-combustion PM control device to meet BACT standards. Generally, the approved BACT technologies included use of "clean" fuels.

Due to the relatively high velocity and volumetric flow rate of the exhaust gas, any type of post-combustion particulate matter control is not technically warranted for refinery fuel fired boilers.

Economic Feasibility:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery boilers and therefore an economic feasibility analysis is not required.

Approximate Cost:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery boilers and therefore an economic feasibility analysis is not required.

Implementation Schedule:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery boilers and therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

SO_2 BACT Options (Boiler #5 F11005 and Boiler #6 F11006)

Option 1: Use of Low Sulfur Refinery Fuel Gas

Description of Option 1: The refinery gas sulfur content is dependent on the efficiency and design parameters of amine scrubbers and other equipment in the SRUs. The refinery fuel gas H_2S content is currently limited by the requirements of NSPS Ja and constitutes a low sulfur fuel that will result in minimal SO_2 emissions from the refinery boilers.

Option 2: Flue Gas Desulfurization (FGD)

Description of Option 2: FGD is commonly used to control SO_2 from solid fuel-combustion, such as coal. FGD technology is based on a variety of wet or dry scrubbing processes. It has demonstrated control efficiencies of up to 80 percent on coal-fired systems; however, FGD has not been commercially accepted in practice for gas-fired sources.

Option 3: Wet Gas Scrubber

Description of Option 3: The use of a wet gas scrubber involves a water spray introduced into the boiler exhaust stream, resulting in the cooling and condensing of organic material. The water vapor condenses onto the organic aerosol which then becomes large enough to settle or be removed by cyclonic collectors, filters, or mist eliminators.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options. A control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Use of Low Sulfur Refinery Fuel Gas – Technically Feasible
Chevron currently combusts only low sulfur fuel gas, or natural gas in their refinery boilers. A review of EPA's RBLC database for process gas fired boilers revealed that the use of low sulfur fuel gas is considered BACT for these emission sources.

Option 2: Flue Gas Desulfurization (FGD) – Technically Infeasible
FGD has not been commercially accepted in practice for gas-fired sources. As such, a review of EPA's RBLC database for process gas fired boilers revealed that FGD has not been used for refinery boilers to meet BACT. Due to the fact that this technology has not been demonstrated in practice for refinery boilers largely due to operational complexity of such systems, this technology is deemed technically infeasible.

Option 3: Wet Gas Scrubber – Technically Infeasible
As previously identified, a review of the EPA's RBLC database for process gas fired boilers revealed that refinery sources listed did not use any post-combustion wet gas scrubbers to meet BACT standards. Generally, the approved BACT technologies included use of "clean" fuels. Due to the relatively high velocity and volumetric flow rate of the exhaust gas, any type of post-combustion SO_2 control is not technically warranted for refinery fuel fired boilers.

<u>Economic Feasibility:</u>

As noted above, Chevron utilizes low sulfur fuel gas which is the only technically feasible control option for refinery boilers and therefore an economic feasibility analysis is not required.

<u>Approximate Cost:</u>

As noted above, Chevron utilizes low sulfur fuel gas which is the only technically feasible control option for refinery boilers and therefore an economic feasibility analysis is not required.

<u>Implementation Schedule:</u>

As noted above, Chevron utilizes low sulfur fuel gas which is the only technically feasible control option for refinery boilers and therefore an implementation schedule is not applicable.

<u>Other Components Affected (if any)</u>

Not Applicable.

NOx BACT Options (Boiler #5 F11005 and Boiler #6 F11006)

Option 1: Proper Burner Design and Operation

Description of Option 1: Proper design of burner and firebox components in the boilers will provide the proper air-to-fuel ratio, residence time, temperature, and combustion zone turbulence essential to maintain low NOx emission levels. Good combustion efficiency relies on both hardware design and operating procedures. Air and fuel flow rates should be limited to vendor specifications to achieve satisfactory fuel efficiency and emission performance.

Option 2: Ultra Low NOx Burners (ULNB)

Description of Option 2: ULNBs, the "next generation" burner after the Low NOx Burners (LNBs), alter the air to fuel ratio in the combustion zone by staging the introduction of air to promote a "lean-premixed" flame and by means of an internal flue gas recirculation. This results in lower combustion temperatures and reduced NOx formation. While the boilers were installed with what could have been considered ULNB technology at the time, further advances in burner design make lower emissions possible. In new installations, NOx emissions as low as 0.01 lb/MMBtu have been achieved. However, based on discussions with relevant vendors, for a retrofit application a value of approximately 0.025 lb/MMBtu is more realistic.

Option 3: Selective Catalytic Reduction (SCR)

Description of Option 3: SCR is a post-combustion, flue gas treatment technology that uses ammonia as a reagent to reduce NOx to molecular nitrogen and water in the presence of a metal oxide catalyst. The chemical reactions involved in the SCR process are:

$$4\,NO + 4\,NH_3 + O_2 \rightarrow 4\,N_2 + 6\,H_2O$$
$$6\,NO_2 + 8\,NH_3 \rightarrow 7\,N_2 + 12\,H_2O$$

Catalyst performance is optimized when oxygen level in the exhaust gas stream is above 2 to 3 volume percent. Due to advances in catalyst design, commercial applications of this technology can now operate over an extended temperature range. Precious metal catalysts, such as platinum, can promote oxidation at temperatures as low as 350°F, and zeolite catalysts can operate up to 1,000°F. SCR systems can achieve NOx reduction efficiencies of up to 90 % and reliable NOx emission levels of about 0.0125 lb/MMBtu. To implement SCR control, ammonia (NH_3) storage and handling systems must be installed. Careful control of the ammonia injection and operating parameters must be maintained to limit NH_3 "slip" (emissions of unreacted ammonia) and maintain desired NOx reduction. NH_3 is also considered a precursor to PM2.5 formation.

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a

technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Proper Burner Design and Operation – Technically Feasible
Chevron currently combusts only fuel gas in their refinery boilers and utilizes good combustion practices. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for process gas fired boilers revealed that proper burner design and operation is considered BACT for these emission sources.

Option 2: Ultra Low NOx Burners (ULNB) – Technically Feasible
The use of ULNB is a technically feasible control option and has been confirmed in a review of EPA's RBLC database for refinery boilers.

Option 3: SCR – Technically Infeasible
The use of SCR is a technically feasible control option for control of NO_X but due to ammonia slip should not be considered technically feasible for control of $PM_{2.5}$.

Economic Feasibility

The economic impact incurred by the use of a pollution control alternative is measured as cost effectiveness. Cost effectiveness is the value obtained by dividing the annual tons of pollutant controlled into the annual cost. This results in a "dollar per ton" effectiveness value used in the economic feasibility analysis. The cost effectiveness calculations for installing ULNB as well as SCR on Boiler #5 F11005 and Boiler #6 F11006 were based upon EPA's Air Pollution Cost Control Manual[1]. This analysis used EPA's "default" cost parameters with the following exception:

- The baseline or uncontrolled NOx emission rate is defined as the existing burner, with its estimated emission rate in lb NOx/MMBtu.

The following tables present the economic feasibility analysis for ULNB installation as well as SCR installation for Boiler #5 F11005 and Boiler #6 F11006.

1 EPA Air Pollution Cost Control Manual, 6^{th} ed, EPA 452/B-02-001, Section 4.2.

SUMMARY OF ULNB COSTS FOR Boiler #5 F11005 and Boiler #6 F11006

Emission Point Number			F11005	F11006
Service			Boiler #5	Boiler #6
Size (MMBtu/hr-HHV)			171.0	171.0
CAPITAL COSTS:				
Purchased Equipment (PE) [1]			$93,662	$93,662
Freight	10%	% of PE [2]	$ 9,366	$ 9,366
Sales Tax	6%	% of PE [2]	$ 5,620	$ 5,620
Purchased Equipment Cost (PEC)			$ 108,819	$ 108,819
Direct Installation Costs				
Foundations	10%	% of PEC [2]	$ 10,882	$ 10,882
Structure, ductwork, stack	15%	% of PEC [2]	NA	NA
Instrumentation (with CEMS)	Quoted Cost		$ 925,000	$ 925,000
Electrical	10%	% of PEC [2]	$ 10,882	$ 10,882
Piping	5%	% of PEC [2]	$ 5,441	$ 5,441
Insulation, lagging for ductwork	5%	% of PEC [2]	$ 5,441	$ 5,441
Painting	5%	% of PEC [2]	$ 5,441	$ 5,441
Direct Installation Costs			$ 963,087	$ 963,087
Direct Costs (DC)			$ 1,071,906	$ 1,071,906
Indirect Costs				
Engineering & Project mgmt.	25%	% of PE [2]	$ 27,205	$ 27,205
Construction and field expenses	20%	% of PE [2]	$ 21,764	$ 21,764
Contractor fees	15%	% of PE [2]	$ 16,323	$ 16,323
Start-up	10%	% of PE [2]	$ 10,882	$ 10,882
Performance test	5%	% of PE [2]	$ 5,441	$ 5,441
Contingencies	10%	% of DC	$ 107,191	$ 107,191
Indirect Costs			$ 188,805	$ 188,805
Total Installed Cost (TIC)			$ 1,260,711	$ 1,260,711
OPERATING COSTS:	NA - Assumed to be the same as existing LNB			

NOx parameters: Conventional vs. ULNB	Emission Factor Lb/MMBtu	Emissions Tons/Year	
2015 Emissions	0.041	9.6	12.2
ULNB Emissions	0.025	5.9	7.4
NOx Reduction		3.7	4.8

Capital Recovery Factor (10%, 10 yr life) Annualized Total Capital Investment [3]	**0.1627**	**x TIC**	**$ 205,175**	**$ 205,175**
Total Annual Costs			**$ 205,175**	**$ 205,175**
NOx Reduction, tons/yr			3.7	4.8
NOx Cost Effectiveness, $/ton reduced			**$ 54,767**	**$ 43,095**

Notes:

1) As obtained from discussions with potential vendors, and as compared to the EPA-approved permit applications. ULNB cost are ratioed based on heater duty.
2) Typical industry allowances as a percentage of purchased equipment costs; based on experience, engineering practices, discussions with potential vendors, and as compared to the EPA-approved permit applications.
3) Annualized Total Capital Investment is estimated using the capital recovery factor for 10-yr life and 10 percent average interest; i.e., CRF = (i(1+i)^n)/((1+i)^n)-1).

As identified in the table, the NOx Cost effectiveness for ULNB installation for Boiler #5 F11005 is $54,767 per ton of NOx abated, and Boiler #6 F11006 is $43,095 per ton of NOx abated including the cost for CEMS installation to monitor emissions. These costs are estimates and as this is a retrofit, could go up substantially. A more detailed engineering study would be required to more accurately determine cost. For these reasons, Chevron considers the installation of ULNB for the boilers as economically unreasonable for the purposes of PM2.5 ambient air quality attainment.

It is important to note that emissions of $PM_{2.5}$ precursors do not correlate directly to emissions of $PM_{2.5}$. Given the identity of the $PM_{2.5}$ precursors, one might assume at first glance that the photochemically produced part of $PM_{2.5}$ could be controlled simply by decreasing emissions of precursors. In actuality, however, formation of $PM_{2.5}$ sulfate, nitrate, and organic-carbon particles does not depend linearly on their precursors. Minimum formation of $PM_{2.5}$ secondary aerosols occurs when the ratios among NOx, VOC, and SO_2 precursors are least favorable for photochemical interactions. Regrettably, however, the ratios least favorable for secondary aerosol formation are not necessarily optimal for control of ozone formation. Thus, the $/ton of $PM_{2.5}$ precursor calculated in the economic feasibility analyses cannot be assumed to translate directly to $PM_{2.5}$ $/ton cost effectiveness. Moreover, NOx and SO_2 emissions from Chevron Salt Lake Refinery sources do not significantly contribute to $PM_{2.5}$ concentrations in the relevant nonattainment areas. Therefore, the actual $PM_{2.5}$ $/ton cost effectiveness may be **approximately ten (10) times more costly than what was calculated as the $/ton cost effectiveness for the $PM_{2.5}$ precursor.**

SUMMARY OF SCR COSTS FOR Boiler #5 F11005 and Boiler #6 F11006

Emission Point Number			F11005	F11006
Service			Boiler #5	Boiler #6
Size (MMBtu/hr-HHV)			171.0	171.0
CAPITAL COSTS:				
Purchased Equipment (PE) [1]				
SCR Unit			$ 521,725	$ 521,725
Ammonia Skid			$ 243,472	$ 243,472
Ammonia Tank			$ 166,953	$ 166,953
Ductwork,dampers,stack,Fan			$ 626,070	$ 626,070
Instrumentation(with CEMS)			$ 368,687	$ 368,687
Freight	10%	% of PE [2]	$ 52,172	$ 52,172
Sales Tax	6%	% of PE [2]	$ 31,303	$ 31,303
Purchased Equipment Cost (PEC)			$ 2,010,383	$ 2,010,383
Direct Installation Costs				
Foundations	10%	% of PEC [2]	$ 201,038	$ 201,038
Structure, ductwork ,stack, Fan	15%	% of PEC [2]	$ 301,557	$ 301,557
Instrumentation (with CEMS)	8%	% of PEC [2]	$ 1,075,778.72	$ 1,075,778.72
Electrical	10%	% of PEC [2]	$ 201,038	$ 201,038
Piping	5%	% of PEC [2]	$ 100,519	$ 100,519
Insulation, lagging for ductwork	5%	% of PEC [2]	$ 100,519	$ 100,519
Painting	5%	% of PEC [2]	$ 100,519	$ 100,519
Direct Installation Costs			$ 2,080,970	$ 2,080,970
Direct Costs (DC)			$ 4,091,353	$ 4,091,353
Indirect Costs				
Engineering & Project mgmt.	25%	% of PE [2]	$ 502,596	$ 502,596
Construction and field expenses	20%	% of PE [2]	$ 402,077	$ 402,077
Contractor fees	15%	% of PE [2]	$ 301,557	$ 301,557
Start-up	10%	% of PE [2]	$ 201,038	$ 201,038
Performance test	5%	% of PE [2]	$ 100,519	$ 100,519
Contingencies	10%	% of DC	$ 409,135	$ 409,135
Indirect Costs			$ 1,916,922	$ 1,916,922
Total Installed Cost (TIC)			$ 6,008,276	$ 6,008,276
OPERATING COSTS:				
Catalyst Replacement (5-yr lifetime)			$ 7,733	$ 7,733
Disposal	50%	% of CR [2]	$ 3,866	$ 3,866
Ammonia (17/46 x tpy NOx removed)	$ 455.00	per ton [4]	$ 161	$ 205
Utilities [3]	$0.066	per kW-hr [4]	$ 17,796	$ 17,796
Operating labor (0.5 hr / 8 hr shift), OP	$ 25.00	per hour [4]	$ 13,688	$ 13,688
Supervisory labor, SL	15%	% of OP [4]	$ 2,053	$ 2,053
Maintenance labor (0.5 hr / 8 hr shift), ML	$ 25.00	per hour [4]	$ 13,688	$ 13,688
Maintenance Materials, MM	100%	% of M [4]	$ 13,688	$ 13,688
Overhead	40%	% of OP+SL+ML+MM [4]	$ 17,246	$ 17,246
Taxes, Insurance, and Admin.	4%	% of TCI [4]	$ 240,331	$ 240,331
Annual Operating Costs			**$ 330,249**	**$ 330,293**
Capital Recovery Factor (10%, 20 yr life) Annualized Total Capital Investment [5]	**0.1175**	**x TIC**	**$ 705,730**	**$ 705,730**
Total Annual Costs			**$ 1,035,979**	**$ 1,036,022**
2015 NOx Emissions, Tons/Yr			9.60	12.20
SCR NOx Emissions, Tons/Yr [6]			0.96	1.22
NOx Reduction, Tons/Yr			8.64	10.98
NOx Cost Effectiveness, $/ton reduced			**$ 119,905**	**$ 94,355**

Notes:

1) As obtained from discussions with potential vendors, and as compared to the EPA-approved permit applications. SCR Unit cost are ratioed based on heater duty.
2) Typical industry allowances as a percentage of purchased equipment costs; based on experience, practices, discussions with potential vendors, and as compared to the EPA-approved permit applications.
3) Required Utility Cost based assumed average of 0.18 KWH per MMBtu/hr of firing duty.
4) Costs based on experience, engineering practices, and the design for this project.
5) Annualized Total Capital Investment is estimated using the capital recovery factor for 20-yr life and average interest; i.e., CRF = (i(1+i)^n)/((1+i)^n)-1).
6) Assumed 90% control efficiency

As identified in the table, the NOx Cost effectiveness for SCR installation for Boiler #5 F11005 is $119,905 per ton of NOx abated and the cost effectiveness for Boiler #6 F11006 is $94,355 per ton of NOx abated. This includes the cost of a CEMS to monitor emissions. This is based on an estimate of the costs to install SCR for similar boilers. Another more detailed cost estimate would be required for this heater to understand all costs including potential metallurgy upgrades as well as piping and fuel gas system upgrades. Therefore, Chevron considers the installation of SCR for boilers as economically unreasonable for the purposes of $PM_{2.5}$ ambient air quality attainment.

It is important to note that emissions of $PM_{2.5}$ precursors do not correlate directly to emissions of $PM_{2.5}$. Given the identity of the $PM_{2.5}$ precursors, one might assume at first glance that the photochemically produced part of $PM_{2.5}$ could be controlled simply by decreasing emissions of precursors. In actuality, however, formation of $PM_{2.5}$ sulfate, nitrate, and organic-carbon particles does not depend linearly on their precursors. Minimum formation of $PM_{2.5}$ secondary aerosols occurs when the ratios among NOx, VOC, and SO_2 precursors are least favorable for photochemical interactions. Regrettably, however, the ratios least favorable for secondary aerosol formation are not necessarily optimal for control of ozone formation. Thus, the $/ton of $PM_{2.5}$ precursor calculated in the economic feasibility analyses cannot be assumed to translate directly to $PM_{2.5}$ $/ton cost effectiveness. Moreover, NOx and SO_2 emissions from Chevron Salt Lake Refinery sources do not significantly contribute to $PM_{2.5}$ concentrations in the relevant nonattainment areas. Therefore, the actual $PM_{2.5}$ $/ton cost effectiveness may be **approximately ten (10) times more costly than what was calculated as the $/ton cost effectiveness for the $PM_{2.5}$ precursor.**

Additionally, as noted above, the operation of SCR emission controls inevitably results an increase in ammonia emissions as ammonia "slip," or excess ammonia that is not consumed in the reduction reaction, is released to the atmosphere. Although ammonia slip can be minimized by good operating practices, it cannot be eliminated entirely. This ammonia slip tends to increase as the catalyst nears the end of its life. The increase of ammonia emissions resulting from the implementation of SCR controls would tend to lessen or negate the air quality benefit of the additional NOx reductions.

$PM_{2.5}$ is a complex and highly variable pollutant, consisting of both "primary" components such as organic matter, and "secondary" components which are formed from the reaction of gaseous pollutants in the atmosphere. Two major secondary components of $PM_{2.5}$ are ammonium sulfate and ammonium nitrate.

SO_2 is a gas-phase species emitted mostly from the combustion of fossil fuels. When SO_2 oxidizes, it forms aerosol sulfuric acid. In the presence of ammonia, however, sulfuric acid will react to form ammonium sulfate, which resides as a particle-phase species in the atmosphere, increasing the atmospheric concentration of $PM_{2.5}$.

Similarly, NO_X, a gas phase species, reacts in the atmosphere to form nitric acid. Nitric acid converts in the presence of ammonia to form ammonium nitrate, one of the five main components of $PM_{2.5}$.

As noted above, the operation of SCR would increase ammonia emissions in the course of reducing NO_X emissions, which would result in secondary formation of $PM_{2.5}$ offsetting the air quality benefit achieved by reducing emissions of NO_X. Therefore SCR emission controls should not be considered feasible for $PM_{2.5}$ control.

Approximate Cost

Based on estimates for ULNB installation on Boiler #5 F11005 and Boiler #6 F11006, the total installed cost is $1,260,711 for each boiler. Therefore ULNB application for Boiler #5 F11005 and Boiler #6 F11006 is economically unreasonable.

Based on estimates for SCR installation on Boiler #5 F11005 and Boiler #6 F11006, the total installed cost is $6,008,276 for each boiler. Therefore SCR application for Boiler #5 F11005 and Boiler #6 F11006 is economically unreasonable

Implementation Schedule

The installation of ULNB and SCR is deemed economically unreasonable and technically infeasible for $PM_{2.5}$ control and so an implementation schedule is not required. However, it is important to note that the installation of either ULNB or SCR would require a process unit shutdown in order to perform the work necessary. Thus, the earliest possible time to complete ULNB or SCR installation would be at the next scheduled major refinery unit turnaround requiring shutdown of the Boiler #5 F11005, or Boiler #6 F11006, if the engineering and procurement required could be completed by then.

Other Components Affected (if any)

In addition to being economically unreasonable, the use of SCR has other substantial Environmental and Energy Impacts. The environmental issues include:

- Use of ammonia reagent, with associated storage, shipping and handling risks;
- Handling and disposal of a degenerated catalyst as a new waste stream;
- Ammonia slip emissions from the system represent a new pollutant emission; and
- Ammonium salt precipitates may increase PM10 and visible plume emissions.

SCR Ammonia Handling Risks

SCR systems typically use either anhydrous ammonia (NH_3 gas) or aqueous ammonia (NH_3 in solution) as the active reagent. Aqueous ammonia reagent is the preferable option due to minimal risks associated with storage and handling compared to anhydrous ammonia. Process design considerations can include abatement approaches as well as mitigation and contingency plans to anticipate and avoid potential incidents.

SCR Catalyst and Hazardous Waste Generation

SCR processes generate a solid chemical waste in the form of spent catalyst that requires treatment and disposal. Since sulfur dioxide will be present in exhaust from the refinery fuel gas-fired units, SCR catalyst fouling is expected to occur at a faster rate than at natural gas-fired installations. Sulfur compounds accelerate catalyst replacement, because fouling generally occurs due to the formation of ammonium bisulfate salts by reaction between SO_2 and ammonia in the catalyst bed. Accumulation of fine solids on the catalyst surfaces accelerates the deterioration of the catalyst, and results in increased pressure drop, reduced efficiency, and more frequent replacement. Upon replacement, the spent catalyst material must be packaged and safely disposed as hazardous waste.

Industry experience with SCR systems at both utility electric generating stations and refineries indicate that the removal and replacement operations can be conducted safely, with insignificant risk to the environment.

SCR Ammonia Slip

Experience indicates that simultaneous, reliable control of ammonia slip (reagent that passes through unreacted) below 10 ppmv, and NOx concentrations below 10 ppmv in the exhaust stream is difficult over the range of operating conditions that occur at a refinery unit.

When SCR catalyst is new and activity is highest, operability is best and the ammonia injection rate can be set to near-stoichiometric levels. As the catalyst ages, its activity decreases. To continuously meet NOx emission limits, the ammonia injection rate must be increased to counteract the less efficient catalyst.

SCR Secondary Byproduct – PM_{10}

Under certain conditions, higher injection rates for ammonia reagent to achieve lower NOx outlet concentrations have been shown to promote formation of secondary particulate, and the phenomenon can be more pronounced as ammonia slip increases. A prime cause of "secondary PM10" formation is the sulfur content in fuel. SCR catalysts effectively oxidize the SO_2 normally present in refinery gas fired boiler exhaust to sulfite (SO_3) and sulfate (SO_4). The SO_3/SO_4 species react with excess ammonia to create extremely fine ammonium bisulfate salt particles that are emitted in the form of secondary PM10 and opacity plumes.

SCR – Energy Impact

In addition to the environmental impacts, there are energy impacts associated with SCR primarily due to increased system pressure drop caused by the SCR catalyst bed. The pressure drop results in elevated back-pressure in the boiler, thus increasing its heat rate and electric demand from the burner fan. The EPA has investigated various systems (Alternative Control Techniques Document) and found that the typical efficiency loss due to pressure drop requirements of the SCR catalyst reactor bed is typically 5 to 15% of heat output.

VOC, CO, and NH_3 BACT Options (Boiler #5 F11005 and Boiler #6 F11006)

Option 1: Proper Burner Design and Operation

Description of Option 1: Proper design of burner and firebox components in the boilers will provide the proper air-to-fuel ratio, residence time, temperature, and combustion zone turbulence essential to maintain low VOC, CO, and NH_3 emission levels. Good combustion efficiency relies on both hardware design and operating procedures. Air and fuel flow rates should be limited to vendor specifications to achieve satisfactory fuel efficiency and emission performance.

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Proper Burner Design and Operation – Technically Feasible
Chevron currently combusts only fuel gas or natural gas in their refinery boilers and utilizes good combustion practices. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for process gas fired boilers revealed that proper burner design and operation is the sole BACT measure for emissions of VOC, CO, and NH_3 from refinery fuel gas fired sources.

Economic Feasibility

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery boilers and therefore an economic feasibility analysis is not required.

Approximate Cost

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery boilers and therefore an economic feasibility analysis is not required.

Implementation Schedule

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery boilers and therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

Results of Analysis

The results of the Boiler #5 F11005 and Boiler #6 F11006 BACT Analysis are summarized in the following table.

Pollutant	Control Option	Technically Feasible (Yes/No)	Cost Effectiveness ($/ton)	BACT Selected
$PM_{10}/PM_{2.5}$	Proper Burner Design and Operation	Yes	NA	Proper Burner Design and Operation
	Post Combustion Control (WGS or ESP)	No	NA	
SO_2	Use of Low Sulfur Refinery Fuel Gas	Yes	NA	Use of Low Sulfur Refinery Fuel Gas
	Flue Gas Desulfurization	No	NA	
	Wet Gas Scrubber	No	NA	
NOx	Proper Burner Design and Operation	Yes	NA	Proper Burner Design and Operation
	Ultra Low NOx Burners	Yes	$54,767/ton (Blr 5) $43,095/ton (Blr 6)	
	SCR	No	$119,905/ton (Blr 5) $94,355 (Blr 6)	
VOC/ NH_3	Proper Burner Design and Operation	Yes	NA	Proper Burner Design and Operation

Recommended Emission Limits and Monitoring Requirements

As a part of this BACT evaluation, Chevron has identified emission limitations and monitoring methods that would be appropriate for each pollutant included in the analysis. For Boilers #5 and #6, Chevron recommends the hydrogen sulfide concentration limitations and monitoring requirements of NSPS Subpart Ja. Chevron does not propose any emission limits or monitoring for other pollutants, because SO_2 is the only pollutant for which Chevron has installed emission controls and thus can maintain control of emission rates.

The table below summarizes the proposed emission limits and monitoring requirements.

Pollutant	Source	Proposed Emission Limit	Proposed Monitoring
SO_2	Refinery Fuel Gas	Fuel gas H_2S concentration – 162 ppmv 3-hour average, 60 ppmv 365-day average	Continuous H_2S Monitor

Crude Unit Heater F21001 BACT Analysis

1. Site and Company/Owner Name

Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. Description of Facility:

Please reference Boiler 1 F11001, Boiler 2 F11002, and Boiler 4 F11004 BACT analysis for a full description of the facility.

3. Recent Permitting Actions (if any):

None

4. Current Emissions (Crude Unit Heater F21001)

For the purposes of this BACT analysis, Chevron has analyzed emissions from the highest emitting fuel fired furnace at the refinery, Crude Unit Heater F21001 (130.0 MMBtu/hr). Conducting the BACT analysis on the highest emitting fuel fired furnace at the refinery will yield the most cost effective $/ton emission reductions for all fuel fired furnaces. Estimated 2015 emissions for F21001 are presented in the following table.

F21001 – 2015 Actual Emissions

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
1.7	1.7	0.01	11.2	1.2	0.7

5. Emission Information / Discussion

Estimated 2015 emissions for Crude Unit Heater F21001 were calculated based on the 2015 fuel consumption and operating schedule, and the following emission factors:

- NOx– Emissions factors from AP-42 Table 1.4.1.
- VOC, PM_{10} and $PM_{2.5}$ – Emission factors from AP-42 Table 1.4.2.
- NH_3 – Development and Selection of Ammonia Emission Factors, August 1994, Table 7.4.
- SO_2 – Based on refinery fuel gas HHV (2015 Emission Inventory) and total sulfur in fuel gas.

Note that F21001 and F21002 vent to atmosphere through a common stack, so for emission inventory purposes emissions are calculated for both units combined. The emissions for each heater were derived by apportioning the combined emissions by heater heat input capacity.

PM_{10} and $PM_{2.5}$ BACT Options (Crude Unit Heater F21001)

Option 1 - Title: Proper Burner Design and Operation

Description of Option 1: Proper design of burner and firebox components in the heaters will provide the proper air-to-fuel ratio, residence time, temperature, and combustion zone turbulence essential to maintain low PM emission levels. Additionally, effective combustion controls avoid fuel-rich conditions that may promote soot formation. Good combustion efficiency relies on both hardware design and operating procedures. Air and fuel flow rates should be limited to vendor specifications to achieve satisfactory fuel efficiency and emission performance.

Option 2 - Title: Post Combustion Particulate Matter Control - Wet Gas Scrubber or Electrostatic Precipitator (ESP)

Description of Option 2: The use of a wet gas scrubber involves a water spray introduced into the furnace exhaust stream, resulting in the cooling and condensing of organic material. The water vapor condenses onto the organic aerosol which then becomes large enough to settle or be removed by cyclonic collectors, filters, or mist eliminators. Wet scrubbers typically obtain an efficiency rate comparable to ESPs of 95% or greater.

ESPs use an electrostatic field to charge particulate matter contained in the gas stream. These charged particles then migrate to a grounded collecting surface. The surface is vibrated or rapped periodically to dislodge the particles, and the particles are then collected in a hopper in the bottom of the unit. The control efficiency for ESPs can range from at least 70 to 93% removal efficiency.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Proper Burner Design and Operation – Technically Feasible
Chevron currently combusts only fuel gas in their refinery furnaces and utilizes good combustion practices. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for process gas fired heaters and boilers revealed that proper burner design and operation is considered BACT for these emission sources.

Option 2: Post Combustion Particulate Matter Control – Technically Infeasible
A review of the EPA's RBLC database for process gas fired heaters and boilers revealed that refinery sources listed did not use any post-combustion PM control device to meet BACT standards. Generally, the approved BACT technologies included use of "clean"

fuels. Due to the relatively high velocity and volumetric flow rate of the exhaust gas, any type of post-combustion particulate matter control is not technically warranted for refinery fuel fired furnaces.

Economic Feasibility:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery furnaces and therefore an economic feasibility analysis is not required.

Approximate Cost:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery furnaces and therefore an economic feasibility analysis is not required.

Implementation Schedule:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery furnaces and therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

SO_2 BACT Options (Crude Unit Heater F21001)

Option 1 Title: Use of Low Sulfur Refinery Fuel Gas

Description of Option 1: The refinery gas sulfur content is dependent on the efficiency and design parameters of amine scrubbers and other equipment in the SRUs. The refinery fuel gas H_2S content is currently limited by the requirements of NSPS Ja and constitutes a low sulfur fuel that will result in minimal SO_2 emissions from the refinery heathers and boilers.

Option 2 Title: Flue Gas Desulfurization (FGD)

Description of Option 2: FGD is commonly used to control SO_2 from solid fuel-combustion, such as coal. FGD technology is based on a variety of wet or dry scrubbing processes. It has demonstrated control efficiencies of up to 80 percent on coal-fired systems; however, FGD has not been commercially accepted in practice for gas-fired sources.

Option 3 - Title: Wet Gas Scrubber

Description of Option 3: The use of a wet gas scrubber involves a water spray introduced into the furnace exhaust stream, resulting in the cooling and condensing of organic material. The water vapor condenses onto the organic aerosol which then becomes large enough to settle or be removed by cyclonic collectors, filters, or mist eliminators.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Use of Low Sulfur Refinery Fuel Gas – Technically Feasible
Chevron currently combusts only low sulfur fuel gas in their refinery furnaces. A review of EPA's RBLC database for process gas fired heaters and boilers revealed that the use of low sulfur fuel gas is considered BACT for these emission sources.

Option 2 Title: Flue Gas Desulfurization (FGD) – Technically Infeasible
FGD has not been commercially accepted in practice for gas-fired sources. As such, a review of EPA's RBLC database for process gas fired heaters and boilers revealed that FGD has not been used for refinery furnaces to meet BACT. Due to the fact that this technology has not been demonstrated in practice for refinery furnaces largely due to operational complexity of such systems, this technology is deemed technically infeasible.

Option 3: Wet Gas Scrubber – Technically Infeasible
As previously identified, a review of the EPA's RBLC database for process gas fired heaters and boilers revealed that refinery sources listed did not use any post-combustion wet gas scrubbers to meet BACT standards. Generally, the approved BACT technologies included use of "clean" fuels. Due to the relatively high velocity and volumetric flow rate of the exhaust gas, any type of post-combustion SO_2 control is not technically warranted for refinery fuel fired furnaces.

Economic Feasibility:

As noted above, Chevron utilizes low sulfur fuel gas which is the only technically feasible control option for refinery furnaces and therefore an economic feasibility analysis is not required.

Approximate Cost:

As noted above, Chevron utilizes low sulfur fuel gas which is the only technically feasible control option for refinery furnaces and therefore an economic feasibility analysis is not required.

Implementation Schedule:

As noted above, Chevron utilizes low sulfur fuel gas which is the only technically feasible control option for refinery furnaces and therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

NOx BACT Options (Crude Unit Heater F21001)

Option 1 - Title: Proper Burner Design and Operation

Description of Option 1: Proper design of burner and firebox components in the heaters will provide the proper air-to-fuel ratio, residence time, temperature, and combustion zone turbulence essential to maintain low NOx emission levels. Good combustion efficiency relies on both hardware design and operating procedures. Air and fuel flow rates should be limited to vendor specifications to achieve satisfactory fuel efficiency and emission performance. Chevron currently has air preheat for this heater and if any other option is chosen a more detailed cost analysis will need to be performed.

Option 2 - Title: Ultra Low NOx Burners (ULNB)

Description of Option 2: ULNBs, the "next generation" burner after the Low NOx Burners (LNBs), alter the air to fuel ratio in the combustion zone by staging the introduction of air to promote a "lean-premixed" flame and by means of an internal flue gas recirculation. This results in lower combustion temperatures and reduced NOx formation. This option is a feasible control for refinery process heaters and boilers; However, it is important to note that the use of air pre-heat with heaters will increase NOx emissions slightly.

Option 3 - Title: Selective Catalytic Reduction (SCR)

Description of Option 3: SCR is a post-combustion, flue gas treatment technology that uses ammonia as a reagent to reduce NOx to molecular nitrogen and water in the presence of a metal oxide catalyst. The chemical reactions involved in the SCR process are:

$$4\,NO + 4\,NH_3 + O_2 \rightarrow 4\,N_2 + 6\,H_2O$$
$$6\,NO_2 + 8\,NH_3 \rightarrow 7\,N_2 + 12\,H_2O$$

Catalyst performance is optimized when oxygen level in the exhaust gas stream is above 2 to 3 volume percent. Due to advances in catalyst design, commercial applications of this technology can now operate over an extended temperature range. Precious metal catalysts, such as platinum, can promote oxidation at temperatures as low as 350°F, and zeolite catalysts can operate up to 1,000°F. SCR systems can achieve NOx reduction efficiencies of greater than 90 % and reliable NOx emission levels of about 0.006 lb/MMBtu. To implement SCR control, ammonia (NH_3) storage and handling systems must be installed. Careful control of the ammonia injection and operating parameters must be maintained to limit NH_3 "slip" (emissions of unreacted ammonia) and maintain desired NOx reduction. NH3 is also considered a precursor to PM2.5 formation.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a

technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Proper Burner Design and Operation – Technically Feasible
Chevron currently combusts only fuel gas in their refinery furnaces and utilizes good combustion practices. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for process gas fired heaters and boilers revealed that proper burner design and operation is considered BACT for these emission sources.

Option 2: Ultra Low NOx Burners (ULNB) – Technically Feasible
The use of ULNB is a technically feasible control option and has been confirmed in a review of EPA's RBLC database for refinery heaters and boilers.

Option 3: SCR – Technically Infeasible
The use of SCR is a technically feasible control option for control of NO_X but due to ammonia slip should not be considered technically feasible for control of $PM_{2.5}$.

Economic Feasibility:

The economic impact incurred by the use of a pollution control alternative is measured as cost effectiveness. Cost effectiveness is the value obtained by dividing the annual tons of pollutant controlled into the annual cost. This results in a "dollar per ton" effectiveness value used in the economic feasibility analysis. The cost effectiveness calculations for installing ULNB as well as SCR on the Crude Unit Heater F21001 were based upon EPA's Air Pollution Cost Control Manual[1]. Based on a review of past BACT determinations the analyses are based on a post-control emission rate of 0.01 lb/MMBtu for ULNB and 0.006 lb/MMBtu for SCR. While 0.01 may be achievable in a new installation of ULNB's, a more realistic 0.25 lb/MMBTU for ULNB was used for this calculation since this is a retrofit application. This analysis used EPA's "default" cost parameters with the following exception:

- The baseline or uncontrolled NOx emission rate is defined as the existing burner, with its estimated emission rate in lb NOx/MMBtu.

The following tables present the economic feasibility analysis for ULNB installation as well as SCR installation for the Crude Unit Heater F21001.

1 EPA Air Pollution Cost Control Manual, 6th ed, EPA 452/B-02-001, Section 4.2.

SUMMARY OF ULNB COSTS FOR F21001

Emission Point Number				F21001
Service				Crude Unit Heater
Size (MMBtu/hr-HHV)				130.00
CAPITAL COSTS:				
Purchased Equipment (PE) [1]				$71,205
Freight	10%	% of PE [2]	$	7,121
Sales Tax	6%	% of PE [2]	$	4,272
Purchased Equipment Cost (PEC)			$	82,598
Direct Installation Costs				
Foundations	10%	% of PEC [2]	$	8,260
Structure, ductwork, stack	15%	% of PEC [2]	$	12,389.70
Instrumentation (with CEMS)	8%	% of PEC [2]	$	474,889.70
Electrical	10%	% of PEC [2]	$	8,260
Piping	5%	% of PEC [2]	$	4,130
Insulation,lagging for ductwork	5%	% of PEC [2]	$	4,130
Painting	5%	% of PEC [2]	$	4,130
Direct Installation Costs			$	516,189
Direct Costs (DC)			$	598,787
Indirect Costs				
Engineering & Project mgmt.	25%	% of PE [2]	$	20,650
Construction and field expenses	20%	% of PE [2]	$	16,520
Contractor fees	15%	% of PE [2]	$	12,390
Start-up	10%	% of PE [2]	$	8,260
Performance test	5%	% of PE [2]	$	4,130
Contingencies	10%	% of DC	$	59,879
Indirect Costs			$	121,827
Total Installed Cost (TIC)			$	720,614
OPERATING COSTS:	NA - Assumed to be the same as existing LNB			

NOx Emission Reduction

	Emission Factor Lb/MMBtu	Emissions TPY
2015 Emissions	0.041	11.2
ULNB Emissions	0.025	6.9
TPY NOx Reduction		4.3

Capital Recovery Factor (10%, 10 yr life) **Annualized Total Capital Investment [3]**	**0.1627**	**x TIC**	**$**	**117,277**
Total Annual Costs			**$**	**117,277**
NOx Reduction, tons/yr				4.3
NOx Cost Effectiveness, $/ton reduced			**$**	**27,252**

Notes:

1) As obtained from discussions with potential vendors, and as compared to the EPA-approved permit applications. ULNB cost are ratioed based on heater duty.
2) Typical industry allowances as a percentage of purchased equipment costs; based on experience, engineering practices, discussions with potential vendors, and as compared to the EPA-approved permit applications.
3) Annualized Total Capital Investment is estimated using the capital recovery factor for 10-yr life and 10 percent average interest; i.e., CRF = (i(1+i)^n)/((1+i)^n)-1).

As identified in the table, the NOx Cost effectiveness for ULNB installation is $27,252 per ton of NOx abated. This is based on an estimate of the costs to install ULNB for similar heaters. Another more detailed cost estimate would be required for this heater to understand all additional costs including potential metallurgy upgrades as well as piping and fuel gas system upgrades. The installation cost also includes a shared CEM installation with F21002. Therefore, Chevron considers the installation of ULNB for heaters and boilers not already equipped with ULNB as economically unreasonable for the purposes of $PM_{2.5}$ ambient air quality attainment.

It is important to note that emissions of $PM_{2.5}$ precursors <u>do not correlate directly to emissions of $PM_{2.5}$</u>. Given the identity of the $PM_{2.5}$ precursors, one might assume at first glance that the photochemically produced part of $PM_{2.5}$ could be controlled simply by decreasing emissions of precursors. In actuality, however, formation of $PM_{2.5}$ sulfate, nitrate, and organic-carbon particles does not depend linearly on their precursors. Minimum formation of $PM_{2.5}$ secondary aerosols occurs when the ratios among NOx, VOC, and SO_2 precursors are least favorable for photochemical interactions. Regrettably, however, the ratios least favorable for secondary aerosol formation are not necessarily optimal for control of ozone formation. Thus, the $/ton of $PM_{2.5}$ <u>precursor</u> calculated in the economic feasibility analyses cannot be assumed to translate directly to $PM_{2.5}$ $/ton cost effectiveness. Moreover, NOx and SO_2 emissions from Chevron Salt Lake Refinery sources do not significantly contribute to $PM_{2.5}$ concentrations in the relevant nonattainment areas. Therefore, the actual $PM_{2.5}$ $/ton cost effectiveness may be <u>**approximately ten (10) times more costly than what was calculated as the $/ton cost effectiveness for the $PM_{2.5}$ precursor.**</u>

SUMMARY OF SCR COSTS FOR F21001

Emission Point Number				F21001
Service				Crude Unit Heater
Size (MMBtu/hr-HHV)				130.00
CAPITAL COSTS:				
Purchased Equipment (PE) [1]				
SCR Unit			$	396,633
Ammonia Skid			$	185,096
Ammonia Tank			$	126,923
Ductwork,dampers,stack,Fan			$	475,960
Instrumentation(with CEMS)			$	280,288
Freight	10%	% of PE [2]	$	39,663
Sales Tax	6%	% of PE [2]	$	23,798
Purchased Equipment Cost (PEC)			$	1,528,361
Direct Installation Costs				
Foundations	10%	% of PEC [2]	$	152,836
Structure, ductwork ,stack, Fan	15%	% of PEC [2]	$	229,254
Instrumentation (with CEMS)	8%	% of PEC [2]	$	577,127.10
Electrical	10%	% of PEC [2]	$	152,836
Piping	5%	% of PEC [2]	$	76,418
Insulation,lagging for ductwork	5%	% of PEC [2]	$	76,418
Painting	5%	% of PEC [2]	$	76,418
Direct Installation Costs			$	1,341,308
Direct Costs (DC)			$	2,869,669
Indirect Costs				
Engineering & Project mgmt.	25%	% of PE [2]	$	382,090
Construction and field expenses	20%	% of PE [2]	$	305,672
Contractor fees	15%	% of PE [2]	$	229,254
Start-up	10%	% of PE [2]	$	152,836
Performance test	5%	% of PE [2]	$	76,418
Contingencies	10%	% of DC	$	286,967
Indirect Costs			$	1,433,238
Total Installed Cost (TIC)			$	4,302,907
OPERATING COSTS:				
Catalyst Replacement (5-yr lifetime)			$	5,879
Disposal	50%	% of CR [2]	$	2,939
Ammonia (17/46 x tpy NOx removed)	$ 455.00	per ton [4]	$	1,702
Utilities [3]	$0.066	per kW-hr [4]	$	13,529
Operating labor (0.5 hr / 8 hr shift), OP	$ 25.00	per hour [4]	$	13,688
Supervisory labor, SL	15%	% of OP [4]	$	2,053
Maintenance labor (0.5 hr / 8 hr shift), ML	$ 25.00	per hour [4]	$	13,688
Maintenance Materials, MM	100%	% of M [4]	$	13,688
Overhead	40%	% of OP+SL+ML+MM [4]	$	17,246
Taxes, Insurance, and Admin.	4%	% of TCI [4]	$	172,116
Annual Operating Costs			**$**	**256,527**
Capital Recovery Factor (10%, 20 yr life) Annualized Total Capital Investment [5]	**0.1175**	**x TIC**	**$**	**505,418**
Total Annual Costs			**$**	**761,944**
2015 NOx Emissions, Tons/Yr				11.2
SCR NOx Emissions, Tons/Yr [6]				1.12
NOx Reduction, Tons/Yr				10.1
NOx Cost Effectiveness, $/ton reduced			**$**	**75,291**

Notes:

1) As obtained from discussions with potential vendors, and as compared to the EPA-approved permit applications. SCR Unit cost are ratioed based on heater duty.
2) Typical industry allowances as a percentage of purchased equipment costs; based on experience, engineering practices, discussions with potential vendors, and as compared to the EPA-approved permit applications.
3) Required Utility Cost based assumed average of 0.18 KWH per MMBtu/hr of firing duty.
4) Costs based on experience, engineering practices, and the design for this project.
5) Annualized Total Capital Investment is estimated using the capital recovery factor for 20-yr life and 10 percent average interest; i.e., CRF = (i(1+i)^n)/((1+i)^n)-1).
6) Assumed 90% control efficiency

As identified in the table, the NOx Cost effectiveness for SCR installation is $75,291 per ton of NOx abated. This is based on an estimate of the costs to install SCR for similar heaters. The installation cost also includes a shared CEM installation with F21002. Another more detailed cost estimate would be required for this heater to understand all costs including potential metallurgy upgrades as well as piping and fuel gas system upgrades. Therefore, Chevron considers the installation of SCR for heaters as economically unreasonable for the purposes of PM2.5 ambient air quality attainment.

It is important to note that emissions of $PM_{2.5}$ precursors do not correlate directly to emissions of $PM_{2.5}$. Given the identity of the $PM_{2.5}$ precursors, one might assume at first glance that the photochemically produced part of $PM_{2.5}$ could be controlled simply by decreasing emissions of precursors. In actuality, however, formation of $PM_{2.5}$ sulfate, nitrate, and organic-carbon particles does not depend linearly on their precursors. Minimum formation of $PM_{2.5}$ secondary aerosols occurs when the ratios among NOx, VOC, and SO_2 precursors are least favorable for photochemical interactions. Regrettably, however, the ratios least favorable for secondary aerosol formation are not necessarily optimal for control of ozone formation. Thus, the $/ton of $PM_{2.5}$ precursor calculated in the economic feasibility analyses cannot be assumed to translate directly to $PM_{2.5}$ $/ton cost effectiveness. Moreover, NOx and SO_2 emissions from Chevron Salt Lake Refinery sources do not significantly contribute to $PM_{2.5}$ concentrations in the relevant nonattainment areas. Therefore, the actual $PM_{2.5}$ $/ton cost effectiveness may be **approximately ten (10) times more costly than what was calculated as the $/ton cost effectiveness for the $PM_{2.5}$ precursor.**

Additionally, as noted above, the operation of SCR emission controls inevitably results an increase in ammonia emissions as ammonia "slip," or excess ammonia that is not consumed in the reduction reaction, is released to the atmosphere. Although ammonia slip can be minimized by good operating practices, it cannot be eliminated entirely. This ammonia slip tends to increase as the catalyst nears the end of its life. The increase of ammonia emissions resulting from the implementation of SCR controls would tend to lessen or negate the air quality benefit of the additional NOx reductions. Therefore SCR emission controls should not be considered feasible for $PM_{2.5}$ control.

Approximate Cost:

Based on estimates for ULNB installation on the Crude Unit Heater F21001, the total installed cost is $720,614. Therefore, ULNB application for the Crude Unit Heater F21001 is economically unreasonable.

Based on estimates for SCR installation on the Crude Unit Heater F21001, the total installed cost is $4,302,907. Therefore SCR application for the Crude Unit Heater F21001 is economically unreasonable.

Implementation Schedule:

The installation of ULNB and is deemed economically unreasonable and an SCR is determined technically infeasible. An implementation schedule, therefore, is not required. However, it is important to note that the installation of either ULNB or SCR would require a process unit

ULNB or SCR installation would be at the next scheduled major refinery unit turnaround requiring shutdown of the Crude Unit Heater F21001. Assuming that the engineering and procurement required could be completed by then.

Other Components Affected (if any):

In addition to being economically unreasonable, the use of SCR has other substantial Environmental and Energy Impacts. The environmental issues include:

- Use of ammonia reagent, with associated storage, shipping and handling risks;
- Handling and disposal of a degenerated catalyst as a new waste stream;
- Ammonia slip emissions from the system represent a new pollutant emission; and
- Ammonium salt precipitates may increase PM10 and visible plume emissions.

SCR Ammonia Handling Risks

SCR systems typically use either anhydrous ammonia (NH_3 gas) or aqueous ammonia (NH_3 in solution) as the active reagent. Aqueous ammonia reagent is the preferable option due to minimal risks associated with storage and handling compared to anhydrous ammonia. Process design considerations can include abatement approaches as well as mitigation and contingency plans to anticipate and avoid potential incidents.

SCR Catalyst and Hazardous Waste Generation

SCR processes generate a solid chemical waste in the form of spent catalyst that requires treatment and disposal. Since sulfur dioxide will be present in exhaust from the refinery fuel gas-fired units, SCR catalyst fouling is expected to occur at a faster rate than at natural gas-fired installations. Sulfur compounds accelerate catalyst replacement, because fouling generally occurs due to the formation of ammonium bisulfate salts by reaction between SO_2 and ammonia in the catalyst bed. Accumulation of fine solids on the catalyst surfaces accelerates the deterioration of the catalyst, and results in increased pressure drop, reduced efficiency, and more frequent replacement. Upon replacement, the spent catalyst material must be packaged and safely disposed as hazardous waste.

Industry experience with SCR systems at both utility electric generating stations and refineries indicate that the removal and replacement operations can be conducted safely, with insignificant risk to the environment.

SCR Ammonia Slip

Experience indicates that simultaneous, reliable control of ammonia slip (reagent that passes through unreacted) below 10 ppmv, and NOx concentrations below 10 ppmv in the exhaust stream is difficult over the range of operating conditions that occur at a refinery unit.

When SCR catalyst is new and activity is highest, operability is best and the ammonia injection rate can be set to near-stoichiometric levels. As the catalyst ages, its activity decreases. To continuously meet NOx emission limits, the ammonia injection rate must be increased to counteract the less efficient catalyst.

SCR Secondary Byproduct – PM_{10}

Under certain conditions, higher injection rates for ammonia reagent to achieve lower NOx outlet concentrations have been shown to promote formation of secondary particulate, and the phenomenon can be more pronounced as ammonia slip increases. A prime cause of "secondary PM10" formation is the sulfur content in fuel. SCR catalysts effectively oxidize the SO_2 normally present in refinery gas fired heater exhaust to sulfite (SO_3) and sulfate (SO_4). The SO_3/SO_4 species react with excess ammonia to create extremely fine ammonium bisulfate salt particles that are emitted in the form of secondary PM10 and opacity plumes.

SCR – Energy Impact

In addition to the environmental impacts, there are energy impacts associated with SCR primarily due to increased system pressure drop caused by the SCR catalyst bed. The pressure drop results in elevated back-pressure in the heater, thus increasing its heat rate and electric demand from the burner fan. The EPA has investigated various systems (Alternative Control Techniques Document) and found that the typical efficiency loss due to pressure drop requirements of the SCR catalyst reactor bed is typically 5 to 15% of heat output.

VOC and NH_3 BACT Options (Crude Unit Heater F21001)

Option 1 - Title: Proper Burner Design and Operation

Description of Option 1: Proper design of burner and firebox components in the heaters will provide the proper air-to-fuel ratio, residence time, temperature, and combustion zone turbulence essential to maintain low VOC and NH_3 emission levels. Good combustion efficiency relies on both hardware design and operating procedures. Air and fuel flow rates should be limited to vendor specifications to achieve satisfactory fuel efficiency and emission performance.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Proper Burner Design and Operation – Technically Feasible
Chevron currently combusts only fuel gas in their refinery furnaces and utilizes good combustion practices. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for process gas fired heaters and boilers revealed that proper burner design and operation is the sole BACT measure for emissions of VOC, CO, and NH_3 from refinery fuel gas fired sources.

Economic Feasibility:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery furnaces and therefore an economic feasibility analysis is not required.

Approximate Cost:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery furnaces and therefore an economic feasibility analysis is not required.

Implementation Schedule:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery furnaces and therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

Results of Analysis

The results of the Crude Unit Heater F21001 BACT Analysis are summarized in the following table.

Pollutant	Control Option	Technically Feasible (Yes/No)	Cost Effectiveness ($/ton)	BACT Selected
$PM_{10}/PM_{2.5}$	Proper Burner Design and Operation	Yes	NA	Proper Burner Design and Operation
	Post Combustion Control (WGS or ESP)	No	NA	
SO_2	Use of Low Sulfur Refinery Fuel Gas	Yes	NA	Use of Low Sulfur Refinery Fuel Gas
	Flue Gas Desulfurization	No	NA	
	Wet Gas Scrubber	No	NA	
NOx	Proper Burner Design and Operation	Yes	NA	Proper Burner Design and Operation
	Ultra Low NOx Burners	Yes	$27,252/ton*	
	SCR	No	$75,291/ton	
VOC/NH_3	Proper Burner Design and Operation	Yes	NA	Proper Burner Design and Operation

* This is based on an estimate of the costs to install ULNB for similar heaters. Another more detailed cost estimate would be required for this heater to understand all additional costs including potential metallurgy upgrades as well as piping and fuel gas system upgrades

Recommended Emission Limits and Monitoring Requirements

As a part of this BACT evaluation, Chevron has identified emission limitations and monitoring methods that would be appropriate for each pollutant included in the analysis. For Heater F21001, Chevron recommends the hydrogen sulfide concentration limitations and monitoring requirements of NSPS Subpart Ja. Chevron does not propose any emission limits or monitoring for other pollutants, because SO_2 is the only pollutant for which Chevron has installed emission controls and thus can maintain control of emission rates.

The table below summarizes the proposed emission limits and monitoring requirements.

Pollutant	Source	Proposed Emission Limit	Proposed Monitoring
SO_2	Refinery Fuel Gas	Fuel gas H_2S concentration – 162 ppmv 3-hour average, 60 ppmv 365-day average	Continuous H_2S Monitor

UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY

MAY 01 2017

DIVISION OF AIR QUALITY

Crude Unit Heater F21002 BACT Analysis

1. Site and Company/Owner Name

Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. Description of Facility:

Please reference Boiler 1 F11001, Boiler 2 F11002, and Boiler 4 F11004 BACT analysis for a full description of the facility.

3. Recent Permitting Actions (if any):

None

4. Current Emissions (Crude Unit Heater F21002)

For the purposes of this BACT analysis, Chevron has analyzed emissions from one of the highest emitting fuel fired furnace at the refinery, Crude Unit Heater F21002 (115.1 MMBtu/hr). Conducting the BACT analysis on a high-emitting fuel fired furnace at the refinery will yield the most cost effective $/ton emission reductions for all fuel fired furnaces. Estimated 2015 emissions for F21002 are presented in the following table.

F21001 – 2015 Actual Emissions

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
1.5	1.5	0.01	10.0	1.1	0.6

5. Emission Information / Discussion

Estimated 2015 emissions for Crude Unit Heater F21002 were calculated based on the 2015 fuel consumption and operating schedule, and the following emission factors:

- NOx– Emissions factors from AP-42 Table 1.4.1.
- VOC, PM_{10} and $PM_{2.5}$ – Emission factors from AP-42 Table 1.4.2.
- NH_3 – Development and Selection of Ammonia Emission Factors, August 1994, Table 7.4.
- SO_2 – Based on refinery fuel gas HHV (2015 Emission Inventory) and total sulfur in fuel gas

Note that F21001 and F21002 vent to atmosphere through a common stack, so for emission inventory purposes emissions are calculated for both units combined. The emissions for each heater were derived by apportioning the combined emissions by heater heat input capacity.

PM_{10} and $PM_{2.5}$ BACT Options (Crude Unit Heater F21002)

Option 1 - Title: Proper Burner Design and Operation

Description of Option 1: Proper design of burner and firebox components in the heaters will provide the proper air-to-fuel ratio, residence time, temperature, and combustion zone turbulence essential to maintain low PM emission levels. Additionally, effective combustion controls avoid fuel-rich conditions that may promote soot formation. Good combustion efficiency relies on both hardware design and operating procedures. Air and fuel flow rates should be limited to vendor specifications to achieve satisfactory fuel efficiency and emission performance.

Option 2 - Title: Post Combustion Particulate Matter Control - Wet Gas Scrubber or Electrostatic Precipitator (ESP)

Description of Option 2: The use of a wet gas scrubber involves a water spray introduced into the furnace exhaust stream, resulting in the cooling and condensing of organic material. The water vapor condenses onto the organic aerosol which then becomes large enough to settle or be removed by cyclonic collectors, filters, or mist eliminators. Wet scrubbers typically obtain an efficiency rate comparable to ESPs of 95% or greater.

ESPs use an electrostatic field to charge particulate matter contained in the gas stream. These charged particles then migrate to a grounded collecting surface. The surface is vibrated or rapped periodically to dislodge the particles, and the particles are then collected in a hopper in the bottom of the unit. The control efficiency for ESPs can range from at least 70 to 93% removal efficiency.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Proper Burner Design and Operation – Technically Feasible
Chevron currently combusts only fuel gas in their refinery furnaces and utilizes good combustion practices. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for process gas fired heaters and boilers revealed that proper burner design and operation is considered BACT for these emission sources.

Option 2: Post Combustion Particulate Matter Control – Technically Infeasible
A review of the EPA's RBLC database for process gas fired heaters and boilers revealed that refinery sources listed did not use any post-combustion PM control device to meet BACT standards. Generally, the approved BACT technologies included use of "clean"

fuels. Due to the relatively high velocity and volumetric flow rate of the exhaust gas, any type of post-combustion particulate matter control is not technically warranted for refinery fuel fired furnaces.

Economic Feasibility:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery furnaces and therefore an economic feasibility analysis is not required.

Approximate Cost:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery furnaces and therefore an economic feasibility analysis is not required.

Implementation Schedule:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery furnaces and therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

SO_2 BACT Options (Crude Unit Heater F21002)

Option 1 Title: Use of Low Sulfur Refinery Fuel Gas

Description of Option 1: The refinery gas sulfur content is dependent on the efficiency and design parameters of amine scrubbers and other equipment in the SRUs. The refinery fuel gas H_2S content is currently limited by the requirements of NSPS Ja and constitutes a low sulfur fuel that will result in minimal SO_2 emissions from the refinery heathers and boilers.

Option 2 Title: Flue Gas Desulfurization (FGD)

Description of Option 2: FGD is commonly used to control SO_2 from solid fuel-combustion, such as coal. FGD technology is based on a variety of wet or dry scrubbing processes. It has demonstrated control efficiencies of up to 80 percent on coal-fired systems; however, FGD has not been commercially accepted in practice for gas-fired sources.

Option 3 - Title: Wet Gas Scrubber

Description of Option 3: The use of a wet gas scrubber involves a water spray introduced into the furnace exhaust stream, resulting in the cooling and condensing of organic material. The water vapor condenses onto the organic aerosol which then becomes large enough to settle or be removed by cyclonic collectors, filters, or mist eliminators.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Use of Low Sulfur Refinery Fuel Gas – Technically Feasible
Chevron currently combusts only low sulfur fuel gas in their refinery furnaces. A review of EPA's RBLC database for process gas fired heaters and boilers revealed that the use of low sulfur fuel gas is considered BACT for these emission sources.

Option 2 Title: Flue Gas Desulfurization (FGD) – Technically Infeasible
FGD has not been commercially accepted in practice for gas-fired sources. As such, a review of EPA's RBLC database for process gas fired heaters and boilers revealed that FGD has not been used for refinery furnaces to meet BACT. Due to the fact that this technology has not been demonstrated in practice for refinery furnaces largely due to operational complexity of such systems, this technology is deemed technically infeasible.

Option 3: Wet Gas Scrubber – Technically Infeasible
As previously identified, a review of the EPA's RBLC database for process gas fired heaters and boilers revealed that refinery sources listed did not use any post-combustion wet gas scrubbers to meet BACT standards. Generally, the approved BACT technologies included use of "clean" fuels. Due to the relatively high velocity and volumetric flow rate of the exhaust gas, any type of post-combustion SO_2 control is not technically warranted for refinery fuel fired furnaces.

Economic Feasibility:

As noted above, Chevron utilizes low sulfur fuel gas which is the only technically feasible control option for refinery furnaces and therefore an economic feasibility analysis is not required.

Approximate Cost:

As noted above, Chevron utilizes low sulfur fuel gas which is the only technically feasible control option for refinery furnaces and therefore an economic feasibility analysis is not required.

Implementation Schedule:

As noted above, Chevron utilizes low sulfur fuel gas which is the only technically feasible control option for refinery furnaces and therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

NOx BACT Options (Crude Unit Heater F21002)

Option 1 - Title: Proper Burner Design and Operation

Description of Option 1: Proper design of burner and firebox components in the heaters will provide the proper air-to-fuel ratio, residence time, temperature, and combustion zone turbulence essential to maintain low NOx emission levels. Good combustion efficiency relies on both hardware design and operating procedures. Air and fuel flow rates should be limited to vendor specifications to achieve satisfactory fuel efficiency and emission performance. Chevron currently has air preheat for this heater and if any other option is chosen a more detailed cost analysis will need to be performed.

Option 2 - Title: Ultra Low NOx Burners (ULNB)

Description of Option 2: ULNBs, the "next generation" burner after the Low NOx Burners (LNBs), alter the air to fuel ratio in the combustion zone by staging the introduction of air to promote a "lean-premixed" flame and by means of an internal flue gas recirculation. This results in lower combustion temperatures and reduced NOx formation. This option is a feasible control for refinery process heaters and boilers; However, it is important to note that the use of air pre-heat with heaters will increase NOx emissions slightly.

Option 3 - Title: Selective Catalytic Reduction (SCR)

Description of Option 3: SCR is a post-combustion, flue gas treatment technology that uses ammonia as a reagent to reduce NOx to molecular nitrogen and water in the presence of a metal oxide catalyst. The chemical reactions involved in the SCR process are:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O$$

Catalyst performance is optimized when oxygen level in the exhaust gas stream is above 2 to 3 volume percent. Due to advances in catalyst design, commercial applications of this technology can now operate over an extended temperature range. Precious metal catalysts, such as platinum, can promote oxidation at temperatures as low as 350°F, and zeolite catalysts can operate up to 1,000°F. SCR systems can achieve NOx reduction efficiencies of greater than 90 % and reliable NOx emission levels of about 0.006 lb/MMBtu. To implement SCR control, ammonia (NH_3) storage and handling systems must be installed. Careful control of the ammonia injection and operating parameters must be maintained to limit NH_3 "slip" (emissions of unreacted ammonia) and maintain desired NOx reduction. NH3 is also considered a precursor to PM2.5 formation.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a

technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Proper Burner Design and Operation – Technically Feasible
Chevron currently combusts only fuel gas in their refinery furnaces and utilizes good combustion practices. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for process gas fired heaters and boilers revealed that proper burner design and operation is considered BACT for these emission sources.

Option 2: Ultra Low NOx Burners (ULNB) – Technically Feasible
The use of ULNB is a technically feasible control option and has been confirmed in a review of EPA's RBLC database for refinery heaters and boilers.

Option 3: SCR – Technically Infeasible
The use of SCR is a technically feasible control option for control of NO_X but due to ammonia slip should not be considered technically feasible for control of $PM_{2.5}$.

<u>Economic Feasibility:</u>

The economic impact incurred by the use of a pollution control alternative is measured as cost effectiveness. Cost effectiveness is the value obtained by dividing the annual tons of pollutant controlled into the annual cost. This results in a "dollar per ton" effectiveness value used in the economic feasibility analysis. The cost effectiveness calculations for installing ULNB as well as SCR on the Crude Unit Heater F21002 were based upon EPA's Air Pollution Cost Control Manual[1]. Based on a review of past BACT determinations the analyses are based on a post-control emission rate of 0.01 lb/MMBtu for ULNB and 0.006 lb/MMBtu for SCR. This analysis used EPA's "default" cost parameters with the following exception:

- The baseline or uncontrolled NOx emission rate is defined as the existing burner, with its estimated emission rate in lb NOx/MMBtu.

The following tables present the economic feasibility analysis for ULNB installation as well as SCR installation for the Crude Unit Heater F21002.

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1 EPA Air Pollution Cost Control Manual, 6th ed, EPA 452/B-02-001, Section 4.2.

SUMMARY OF ULNB COSTS FOR F21002

Emission Point Number			F21002
Service			Crude Unit Heater
Size (MMBtu/hr-HHV)			115.10
CAPITAL COSTS:			
Purchased Equipment (PE) [1]			$63,044
Freight	10%	% of PE [2]	$ 6,304
Sales Tax	6%	% of PE [2]	$ 3,783
Purchased Equipment Cost (PEC)			$ 73,246
Direct Installation Costs			
Foundations	10%	% of PEC [2]	$ 7,325
Structure, ductwork, stack	15%	% of PEC [2]	$ 10,986.92
Instrumentation (with CEMS)	8%	% of PEC [2]	$ 467,993.46
Electrical	10%	% of PEC [2]	$ 7,325
Piping	5%	% of PEC [2]	$ 3,662
Insulation,lagging for ductwork	5%	% of PEC [2]	$ 3,662
Painting	5%	% of PEC [2]	$ 3,662
Direct Installation Costs			$ 504,617
Direct Costs (DC)			$ 577,863
Indirect Costs			
Engineering & Project mgmt.	25%	% of PE [2]	$ 18,312
Construction and field expenses	20%	% of PE [2]	$ 14,649
Contractor fees	15%	% of PE [2]	$ 10,987
Start-up	10%	% of PE [2]	$ 7,325
Performance test	5%	% of PE [2]	$ 3,662
Contingencies	10%	% of DC	$ 57,786
Indirect Costs			$ 112,721
Total Installed Cost (TIC)			$ 690,583
OPERATING COSTS:	NA - Assumed to be the same as existing LNB		

NOx Emission Reduction

	Emission Factor Lb/MMBtu	Emissions TPY
2015 Emissions	0.041	10.0
ULNB Emissions	0.025	6.1
NOx Reduction		3.8

Capital Recovery Factor (10%, 10 yr life) Annualized Total Capital Investment [3]	**0.1627**	**x TIC**	**$ 112,389**
Total Annual Costs			**$ 112,389**
NOx Reduction, tons/yr			3.8
NOx Cost Effectiveness, $/ton reduced			**$ 29,246**

Notes:

1) As obtained from discussions with potential vendors, and as compared to the EPA-approved permit applications. ULNB cost are ratioed based on heater duty.
2) Typical industry allowances as a percentage of purchased equipment costs; based on experience, engineering practices, discussions with potential vendors, and as compared to the EPA-approved permit applications.
3) Annualized Total Capital Investment is estimated using the capital recovery factor for 20-yr life and 10 percent average interest; i.e., CRF = (i(1+i)^n)/((1+i)^n)-1).

As identified in the table, the NOx Cost effectiveness for ULNB installation is $29,246 per ton of NOx abated. This is based on an estimate of the costs to install ULNB for similar heaters. Another more detailed cost estimate would be required for this heater to understand all additional costs including potential metallurgy upgrades as well as piping and fuel gas system upgrades. The installation cost also includes a shared CEM installation with F21001. Therefore, Chevron considers the installation of ULNB for heaters and boilers not already equipped with ULNB as economically unreasonable for the purposes of $PM_{2.5}$ ambient air quality attainment.

It is important to note that emissions of $PM_{2.5}$ precursors do not correlate directly to emissions of $PM_{2.5}$. Given the identity of the $PM_{2.5}$ precursors, one might assume at first glance that the photochemically produced part of $PM_{2.5}$ could be controlled simply by decreasing emissions of precursors. In actuality, however, formation of $PM_{2.5}$ sulfate, nitrate, and organic-carbon particles does not depend linearly on their precursors. Minimum formation of $PM_{2.5}$ secondary aerosols occurs when the ratios among NOx, VOC, and SO_2 precursors are least favorable for photochemical interactions. Regrettably, however, the ratios least favorable for secondary aerosol formation are not necessarily optimal for control of ozone formation. Thus, the $/ton of $PM_{2.5}$ precursor calculated in the economic feasibility analyses cannot be assumed to translate directly to $PM_{2.5}$ $/ton cost effectiveness. Moreover, NOx and SO_2 emissions from Chevron Salt Lake Refinery sources do not significantly contribute to $PM_{2.5}$ concentrations in the relevant nonattainment areas. Therefore, the actual $PM_{2.5}$ $/ton cost effectiveness may be **approximately ten (10) times more costly than what was calculated as the $/ton cost effectiveness for the $PM_{2.5}$ precursor.**

SUMMARY OF SCR COSTS FOR F21002

Emission Point Number				F21002
Service				Crude Unit Heater
Size (MMBtu/hr-HHV)				115.1
CAPITAL COSTS:				
Purchased Equipment (PE) [1]				
SCR Unit			$	351,173
Ammonia Skid			$	163,881
Ammonia Tank			$	112,376
Ductwork,dampers,stack,Fan			$	421,408
Instrumentation(with CEMS)			$	248,163
Freight	10%	% of PE [2]	$	35,117
Sales Tax	6%	% of PE [2]	$	21,070
Purchased Equipment Cost (PEC)			$	1,353,188
Direct Installation Costs				
Foundations	10%	% of PEC [2]	$	135,319
Structure, ductwork ,stack, Fan	15%	% of PEC [2]	$	202,978
Instrumentation (with CEMS)	8%	% of PEC [2]	$	563,989.07
Electrical	10%	% of PEC [2]	$	135,319
Piping	5%	% of PEC [2]	$	67,659
Insulation,lagging for ductwork	5%	% of PEC [2]	$	67,659
Painting	5%	% of PEC [2]	$	67,659
Direct Installation Costs			$	1,240,583
Direct Costs (DC)			$	2,593,770
Indirect Costs				
Engineering & Project mgmt.	25%	% of PE [2]	$	338,297
Construction and field expenses	20%	% of PE [2]	$	270,638
Contractor fees	15%	% of PE [2]	$	202,978
Start-up	10%	% of PE [2]	$	135,319
Performance test	5%	% of PE [2]	$	67,659
Contingencies	10%	% of DC	$	259,377
Indirect Costs			$	1,274,268
Total Installed Cost (TIC)			$	3,868,038
OPERATING COSTS:				
Catalyst Replacement (5-yr lifetime)			$	5,205
Disposal	50%	% of CR [2]	$	2,602
Ammonia (17/46 x tpy NOx removed)	$ 455.00	per ton [4]	$	1,507
Utilities [3]	$0.066	per kW-hr [4]	$	11,978
Operating labor (0.5 hr / 8 hr shift), OP	$ 25.00	per hour [4]	$	13,688
Supervisory labor, SL	15%	% of OP [4]	$	2,053
Maintenance labor (0.5 hr / 8 hr shift), ML	$ 25.00	per hour [4]	$	13,688
Maintenance Materials, MM	100%	% of M [4]	$	13,688
Overhead	40%	% of OP+SL+ML+MM [4]	$	17,246
Taxes, Insurance, and Admin.	4%	% of TCI [4]	$	154,722
Annual Operating Costs			**$**	**236,376**
Capital Recovery Factor (10%, 20 yr life) Annualized Total Capital Investment [5]	**0.1175**	**x TIC**	**$**	**454,338**
Total Annual Costs			**$**	**690,714**
2015 NOx Emissions, Tons/Yr				10.0
SCR NOx Emissions, Tons/Yr [6]				1.00
NOx Reduction, Tons/Yr				9.0
NOx Cost Effectiveness, $/ton reduced			**$**	**77,088**

Notes:

1) As obtained from discussions with potential vendors, and as compared to the EPA-approved permit applications. SCR Unit cost are ratioed based on heater duty.
2) Typical industry allowances as a percentage of purchased equipment costs; based on experience, engineering practices, discussions with potential vendors, and as compared to the EPA-approved permit applications.
3) Required Utility Cost based assumed average of 0.18 KWH per MMBtu/hr of firing duty.
4) Costs based on experience, engineering practices, and the design for this project.
5) Annualized Total Capital Investment is estimated using the capital recovery factor for 20-yr life and 10 percent average interest; i.e., CRF = (i(1+i)^n)/((1+i)^n)-1).
6) Based on 0.006 lb/MMBtu

As identified in the table, the NOx Cost effectiveness for SCR installation is $77,088 per ton of NOx abated. This is based on an estimate of the costs to install SCR for similar heaters. The installation cost also includes a shared CEM installation with F21001. Another more detailed cost estimate would be required for this heater to understand all additional costs including potential metallurgy upgrades as well as piping and fuel gas system upgrades. Therefore, Chevron considers the installation of SCR for heaters and boilers as economically unreasonable for the purposes of $PM_{2.5}$ ambient air quality attainment.

It is important to note that emissions of $PM_{2.5}$ precursors do not correlate directly to emissions of $PM_{2.5}$. Given the identity of the $PM_{2.5}$ precursors, one might assume at first glance that the photochemically produced part of $PM_{2.5}$ could be controlled simply by decreasing emissions of precursors. In actuality, however, formation of $PM_{2.5}$ sulfate, nitrate, and organic-carbon particles does not depend linearly on their precursors. Minimum formation of $PM_{2.5}$ secondary aerosols occurs when the ratios among NOx, VOC, and SO_2 precursors are least favorable for photochemical interactions. Regrettably, however, the ratios least favorable for secondary aerosol formation are not necessarily optimal for control of ozone formation. Thus, the $/ton of $PM_{2.5}$ precursor calculated in the economic feasibility analyses cannot be assumed to translate directly to $PM_{2.5}$ $/ton cost effectiveness. Moreover, NOx and SO_2 emissions from Chevron Salt Lake Refinery sources do not significantly contribute to $PM_{2.5}$ concentrations in the relevant nonattainment areas. Therefore, the actual $PM_{2.5}$ $/ton cost effectiveness may be **approximately ten (10) times more costly than what was calculated as the $/ton cost effectiveness for the $PM_{2.5}$ precursor.**

Additionally, as noted above, the operation of SCR emission controls inevitably results an increase in ammonia emissions as ammonia "slip," or excess ammonia that is not consumed in the reduction reaction, is released to the atmosphere. Although ammonia slip can be minimized by good operating practices, it cannot be eliminated entirely. This ammonia slip tends to increase as the catalyst nears the end of its life. The increase of ammonia emissions resulting from the implementation of SCR controls would tend to lessen or negate the air quality benefit of the additional NOx reductions. Therefore SCR emission controls should not be considered feasible for $PM_{2.5}$ control.

Approximate Cost:

Based on estimates for ULNB installation on the Crude Unit Heater F21002, the total installed cost is $690,583. Therefore, ULNB application for the Crude Unit Heater F21002 is economically unreasonable.

Based on estimates for SCR installation on the Crude Unit Heater F21002, the total installed cost is $3,868,038. Therefore SCR application for the Crude Unit Heater F21002 is economically unreasonable.

Implementation Schedule:

The installation of ULNB and SCR is deemed economically unreasonable and so an implementation schedule is not required. However, it is important to note that the installation of either ULNB or SCR would require a process unit shutdown in order to perform the work necessary. Thus, the earliest possible time to complete ULNB or SCR installation would be at the next scheduled major refinery unit turnaround requiring shutdown of the Crude Unit Heater F21002. Assuming that the engineering and procurement required could be completed by then.

Other Components Affected (if any):

In addition to being economically unreasonable, the use of SCR has other substantial Environmental and Energy Impacts. The environmental issues include:

- Use of ammonia reagent, with associated storage, shipping and handling risks;
- Handling and disposal of a degenerated catalyst as a new waste stream;
- Ammonia slip emissions from the system represent a new pollutant emission; and
- Ammonium salt precipitates may increase PM10 and visible plume emissions.

SCR Ammonia Handling Risks

SCR systems typically use either anhydrous ammonia (NH_3 gas) or aqueous ammonia (NH_3 in solution) as the active reagent. Aqueous ammonia reagent is the preferable option due to minimal risks associated with storage and handling compared to anhydrous ammonia. Process design considerations can include abatement approaches as well as mitigation and contingency plans to anticipate and avoid potential incidents.

SCR Catalyst and Hazardous Waste Generation

SCR processes generate a solid chemical waste in the form of spent catalyst that requires treatment and disposal. Since sulfur dioxide will be present in exhaust from the refinery fuel gas-fired units, SCR catalyst fouling is expected to occur at a faster rate than at natural gas-fired installations. Sulfur compounds accelerate catalyst replacement, because fouling generally occurs due to the formation of ammonium bisulfate salts by reaction between SO_2 and ammonia in the catalyst bed. Accumulation of fine solids on the catalyst surfaces accelerates the deterioration of the catalyst, and results in increased pressure drop, reduced efficiency, and more frequent replacement. Upon replacement, the spent catalyst material must be packaged and safely disposed as hazardous waste.

Industry experience with SCR systems at both utility electric generating stations and refineries indicate that the removal and replacement operations can be conducted safely, with insignificant risk to the environment.

SCR Ammonia Slip

Experience indicates that simultaneous, reliable control of ammonia slip (reagent that passes through unreacted) below 10 ppmv, and NOx concentrations below 10 ppmv in the exhaust stream is difficult over the range of operating conditions that occur at a refinery unit.

When SCR catalyst is new and activity is highest, operability is best and the ammonia injection rate can be set to near-stoichiometric levels. As the catalyst ages, its activity decreases. To continuously meet NOx emission limits, the ammonia injection rate must be increased to counteract the less efficient catalyst.

SCR Secondary Byproduct – PM_{10}

Under certain conditions, higher injection rates for ammonia reagent to achieve lower NOx outlet concentrations have been shown to promote formation of secondary particulate, and the phenomenon can be more pronounced as ammonia slip increases. A prime cause of "secondary PM10" formation is the sulfur content in fuel. SCR catalysts effectively oxidize the SO_2 normally present in refinery gas fired heater exhaust to sulfite (SO_3) and sulfate (SO_4). The SO_3/SO_4 species react with excess ammonia to create extremely fine ammonium bisulfate salt particles that are emitted in the form of secondary PM10 and opacity plumes.

SCR – Energy Impact

In addition to the environmental impacts, there are energy impacts associated with SCR primarily due to increased system pressure drop caused by the SCR catalyst bed. The pressure drop results in elevated back-pressure in the heater, thus increasing its heat rate and electric demand from the burner fan. The EPA has investigated various systems (Alternative Control Techniques Document) and found that the typical efficiency loss due to pressure drop requirements of the SCR catalyst reactor bed is typically 5 to 15% of heat output.

VOC and NH_3 BACT Options (Crude Unit Heater F21002)

Option 1 - Title: Proper Burner Design and Operation

Description of Option 1: Proper design of burner and firebox components in the heaters will provide the proper air-to-fuel ratio, residence time, temperature, and combustion zone turbulence essential to maintain low VOC, CO, and NH_3 emission levels. Good combustion efficiency relies on both hardware design and operating procedures. Air and fuel flow rates should be limited to vendor specifications to achieve satisfactory fuel efficiency and emission performance.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Proper Burner Design and Operation – Technically Feasible
Chevron currently combusts only fuel gas in their refinery furnaces and utilizes good combustion practices. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for process gas fired heaters and boilers revealed that proper burner design and operation is the sole BACT measure for emissions of VOC, CO, and NH_3 from refinery fuel gas fired sources.

Economic Feasibility:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery furnaces and therefore an economic feasibility analysis is not required.

Approximate Cost:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery furnaces and therefore an economic feasibility analysis is not required.

Implementation Schedule:

As noted above, Chevron utilizes proper burner design and operation which is the only technically feasible control option for refinery furnaces and therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

Results of Analysis

The results of the Crude Unit Heater F21002 BACT Analysis are summarized in the following table.

Pollutant	Control Option	Technically Feasible (Yes/No)	Cost Effectiveness ($/ton)	BACT Selected
$PM_{10}/PM_{2.5}$	Proper Burner Design and Operation	Yes	NA	Proper Burner Design and Operation
	Post Combustion Control (WGS or ESP)	No	NA	
SO_2	Use of Low Sulfur Refinery Fuel Gas	Yes	NA	Use of Low Sulfur Refinery Fuel Gas
	Flue Gas Desulfurization	No	NA	
	Wet Gas Scrubber	No	NA	
NOx	Proper Burner Design and Operation	Yes	NA	Proper Burner Design and Operation
	Ultra Low NOx Burners	Yes	$29,246/ton*	
	SCR	No	$77,088/ton	
VOC/NH_3	Proper Burner Design and Operation	Yes	NA	Proper Burner Design and Operation

* This is based on an estimate of the costs to install ULNB for similar heaters. Another more detailed cost estimate would be required for this heater to understand all additional costs including potential metallurgy upgrades as well as piping and fuel gas system upgrades

Recommended Emission Limits and Monitoring Requirements

As a part of this BACT evaluation, Chevron has identified emission limitations and monitoring methods that would be appropriate for each pollutant included in the analysis. For Heater F21002, Chevron recommends the hydrogen sulfide concentration limitations and monitoring requirements of NSPS Subpart Ja. Chevron does not propose any emission limits or monitoring for other pollutants, because SO_2 is the only pollutant for which Chevron has installed emission controls and thus can maintain control of emission rates.

The table below summarizes the proposed emission limits and monitoring requirements.

Pollutant	Source	Proposed Emission Limit	Proposed Monitoring
SO_2	Refinery Fuel Gas	Fuel gas H_2S concentration – 162 ppmv 3-hour average, 60 ppmv 365-day average	Continuous H_2S Monitor

Cooling Towers #1, #2, #3, #4 BACT Analysis

1. Site and Company/Owner Name

Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. Description of Facility:

Please reference Boiler 1 F11001, Boiler 2 F11002, and Boiler 4 F11004 BACT analysis for a full description of the facility.

3. Recent Permitting Actions (if any):

Cooling Tower #2 was permitted in 2009 and controls were determined to be BACT by the state of Utah. Cooling Tower #3 was permitted in 2004 with controls determined to be BACT by the state of Utah.

4. Current Emissions (Cooling Towers #1, #2, #3, #4)

For the purposes of this BACT analysis, Chevron has grouped Cooling Towers #1, #2, #3, and #4 together. These cooling towers have been grouped together for this BACT analysis based on their similar operation and emissions. All cooling towers utilize high efficiency drift elimination systems and are monitored for VOC emissions according to the requirements in 40 CFR 63 Subpart CC (Refinery MACT I). Estimated 2015 emissions for all cooling towers are presented in the following table.

Cooling Towers #1, #2, #3, #4 – 2015 Actual Emissions

Cooling Tower	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
#1	5.4	0.7	N/A	N/A	0.726	N/A
#2	0.5	0.1	N/A	N/A	0.146	N/A
#3	0.5	0.1	N/A	N/A	1.657	N/A
#4	1.6	0.2	N/A	N/A	0.116	N/A

5. Emission Information / Discussion

Cooling Tower emissions were estimated as follows:

- Cooling water VOCs were estimated based on monitoring results from the El Paso monitoring method.
- Particulate matter emissions were estimated based on total dissolved solids (TDS) content determined for the 2015 Emission Inventory, and the actual tower drift rate.

Cooling Towers #1, #2, #3, #4 BACT Analysis

PM_{10} and $PM_{2.5}$ BACT Options (Cooling Towers #1, #2, #3, and #4)

Option 1 - Title: High Efficiency Drift Eliminator

> **Description of Option 1:** High efficiency drift eliminators can substantially reduce the release of aerosol droplets in cooling towers. Drift eliminator sections consist of several varieties of structured media with tortuous air pathways. Changes of directions of the air flow passing through the eliminator promote removal of droplets by coagulation and impaction on the eliminator surfaces. Aerosol generation is reduced with these eliminators compared to the 0.02 percent of circulating water flow (AP-42 Table 13.4-1) for "uncontrolled towers."

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

> **Option 1: High Efficiency Drift Eliminator – Technically Feasible**
> A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for cooling towers revealed that high efficiency drift eliminators is considered BACT for these emission sources.

Economic Feasibility:

Chevron currently operates high efficiency drift eliminators on their cooling towers with a drift loss percent of less than 0.01 percent of circulating water flow rate. As noted above, the RBLC database notes that high efficiency drift eliminators are considered BACT which is the only technically feasible control option for the refinery cooling towers. Therefore an economic feasibility analysis is not required.

Approximate Cost:

Chevron currently operates high efficiency drift eliminators on their cooling towers with a drift loss percent of less than 0.01 percent of circulating water flow rate. As noted above, the RBLC database notes that high efficiency drift eliminators are considered BACT which is the only technically feasible control option for the refinery cooling towers. Therefore an economic feasibility analysis is not required.

Implementation Schedule:

Chevron currently operates high efficiency drift eliminators on their cooling towers with a drift loss percent of less than 0.01 percent of circulating water flow rate. As noted above, the RBLC database notes that high efficiency drift eliminators are considered BACT which is the only technically feasible control option for the refinery cooling towers. Therefore an implementation schedule is not required.

Other Components Affected (if any)

Not Applicable.

VOC BACT Options (Cooling Towers #1, #2, #3, and #4)

Option 1 - Title: Meet Federal Regulatory Standards

Description of Option 1: Under the heat exchange system monitoring standards of 40 CFR 63 Subpart CC (Refinery MACT I), applicable heat exchange systems/cooling towers will be subject to VOC monitoring, recordkeeping, and repair requirements. A review of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) indicates that previously approved BACT determinations include compliance with a heat exchange system leak detection and repair program as identified in the revised Refinery MACT I.

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Meet Federal Regulatory Standards – Technically Feasible
Chevron meets and will continue to meet the regulatory control requirements for heat exchange systems (including cooling towers) subject to 40 CFR Part 63 Subpart CC. A review of EPA's RBLC indicates that previously approved BACT determinations for cooling towers include compliance with a heat exchange system leak detection and repair program as identified in the revised Refinery MACT I.

Economic Feasibility

As noted above, Chevron currently meets and will continue to meet the requirements for cooling towers subject to 40 CFR Part 63 Subpart CC which is the only technically feasible control option. Therefore an economic feasibility analysis is not required.

Approximate Cost

As noted above, Chevron currently meets and will continue to meet the requirements for cooling towers subject to 40 CFR Part 63 Subpart CC which is the only technically feasible control option. Therefore an economic feasibility analysis is not required.

Implementation Schedule

As noted above, Chevron currently meets and will continue to meet the requirements for cooling towers subject to 40 CFR Part 63 Subpart CC which is the only technically feasible control option. Therefore an implementation schedule is not applicable.

Other Components Affected (if any):

Not Applicable.

Cooling Towers #1, #2, #3, #4 BACT Analysis

Results of Analysis

The results of the Cooling Tower BACT Analysis are summarized in the following table.

Pollutant	Control Option	Technically Feasible (Yes/No)	Cost Effectiveness ($/ton)	BACT Selected
$PM_{10}/PM_{2.5}$	High Efficiency Drift Eliminator	Yes	NA	Proper Design and Operation
VOC	Meet Applicable Federal Regulatory Standards	Yes	NA	Meet Applicable Federal Regulatory Standards

Recommended Emission Limits and Monitoring Requirements

As a part of this BACT evaluation, Chevron has identified emission limitations and monitoring methods that would be appropriate for each pollutant included in the analysis. For the cooling towers, Chevron proposes to meet the VOC emission limitations and monitoring requirements of Refinery MACT I. Chevron does not propose emission limits or monitoring for other pollutants.

The table below summarizes the proposed emission limits and monitoring requirements.

Pollutant	Source	Proposed Emission Limit	Proposed Monitoring
VOC	Cooling Tower #1	6.2 ppmv total strippable hydrocarbon	Monthly El Paso Method Monitoring
	Cooling Tower #2		
	Cooling Tower #3		
	Cooling Tower #4		

Note that the 6.2 ppmv limit presented in the above table is not an enforceable emission limit, but instead is a leak action level, requiring repairs to leaking equipment.

Emergency Diesel Engines BACT Analysis

1. **Site and Company/Owner Name**

   Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. **Description of Facility:**

   Please reference Boiler 1 F11001, Boiler 2 F11002, and Boiler 4 F11004 BACT analysis for a full description of the facility.

3. **Recent Permitting Actions (if any):**

   None.

4. **Current Emissions (Emergency Diesel Engines)**

   Chevron operates 17 stationary diesel engines used to provide power or work in event of an emergency, such as a power failure or fire. The engines include electrical generators, pumps, and air compressors, and range in power output from 168 Horsepower (HP) to 1,676 HP. For the purposes of this BACT analysis, Chevron has grouped all of the emergency diesel engines together. Six of the engines are Tier III engines, whereas the other engines are of non-tier design. The Tier III engines are designated with an asterisk (*) in the table below. These engines have been grouped together for this BACT analysis based on their similar operation and they are of similar design.

   Chevron has used 2015 actual emissions from the emergency engines in this analysis. Estimated emissions for all emergency engines are presented in the following tables. Emissions were calculated for all engines in the aggregate, using total fuel consumption. The table below shows the total emissions, and apportions the emissions to each individual engine according to its power output.

Emergency Diesel Engines – 2015 Actual Emissions Tons/Yr

Engine	HP	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
Admin Bldg Emergency Generator*	422	0.018	0.018	0.014	0.216	0.017	N/A
2nd North Substation Emergency Generator	750	0.031	0.031	0.025	0.384	0.030	N/A
3rd North Emergency Generator	1490	0.062	0.062	0.050	0.762	0.060	N/A
Crude Substation Emergency Generator	820	0.034	0.034	0.028	0.419	0.033	N/A
Crude Unit Emergency CW Pump Engine	665	0.028	0.028	0.022	0.340	0.027	N/A
VGO Substation Emergency	755	0.031	0.031	0.025	0.386	0.031	N/A

Emergency Diesel Engines BACT Analysis

Engine	HP	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
Generator							
P-437 Emergency HF Mitigation Pump Engine	770	0.032	0.032	0.026	0.394	0.031	N/A
P-437A Emergency HF Mitigation Pump Engine	770	0.032	0.032	0.026	0.394	0.031	N/A
GRU Substation Emergency Generator	750	0.031	0.031	0.025	0.384	0.030	N/A
Emergency Air Compressor*	575	0.024	0.024	0.019	0.294	0.023	N/A
Emergency Air Compressor*	575	0.024	0.024	0.019	0.294	0.023	N/A
WWTP Emergency Generator	227	0.009	0.009	0.008	0.116	0.009	N/A
Portable Generator	227	0.009	0.009	0.008	0.116	0.009	N/A
Fire Water Emergency Backup Pump*	400	0.017	0.017	0.013	0.205	0.016	N/A
Fire Water Emergency Backup Pump*	400	0.017	0.017	0.013	0.205	0.016	N/A
Tank Car Loading Rack Emergency Power*	168	0.007	0.007	0.006	0.086	0.007	N/A
HRFP Emergency Power	1676	0.070	0.070	0.056	0.857	0.068	N/A
Totals		0.475	0.475	0.385	5.851	0.464	**N/A**

*Tier III Engine

The cost analyses for this evaluation were based on installing controls on the HRFP Emergency Power engine, as it is the largest of the emergency engines, and is representative of this category. Costs for other engines are expected to be roughly proportional to their power output.

5. Emission Information / Discussion

SO_2 emissions were estimated assuming that all of the sulfur in fuel oil was converted to SO_2. All other pollutants were estimated using the emission factors in AP-42 Chapter 3.3.

PM_{10} and $PM_{2.5}$ BACT Options (Emergency Diesel Engines)

Option 1 - Title: Meet Federal Regulatory Requirements

Description of Option 1: Description of Option 1: The existing emergency engines must meet the federal requirements under 40 CFR Part 63 Subpart ZZZZ. Units that are subject to a federal NESHAP meet BACT requirements in order to comply with the federal regulations. The engines are required to meet the requirements for emergency engines in Subpart ZZZZ.

Option 2 - Title: Operate Engine Meeting Tier Nonroad Regulatory Requirements

Description of Option 2: All new engines manufactured in the United States are required to meet emission limits specified in "Tiers," based upon date of manufacture. The current tier is Tier IV. A review of the EPA's RBLC indicates that the use of Tier-compliant engines is BACT for emergency engines. Several of the emergency engines currently operated at Chevron are Tier III engines.

Option 3 - Title: Post Combustion Particulate Matter Control – Catalyst

Description of Option 3: The use of a retrofit catalyst on the engine exhaust can reduce emissions of a number of pollutants, including CO, VOC, and PM_{10} and $PM_{2.5}$. Oxidation catalysts can achieve a PM reduction efficiency of up to 91%.

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Meet Federal Regulatory Standards – Technically Feasible
Chevron currently combusts only ultra-low sulfur diesel (ULSD) in their emergency engines and utilizes good combustion practices. Additionally, as required by Subpart ZZZZ, Chevron must comply with specified maintenance schedules (crankcase oil, belts and hoses, etc.), and minimize time at idle. A review of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) indicates that previously approved BACT determinations include compliance with applicable federal regulations.

Option 2: Operate Engine Meeting Tier Nonroad Regulatory Requirements – Technically Infeasible (for currently Non-Tier Engines)
A review of the EPA's RBLC database for emergency diesel engines indicates that the use of Tier III engines has been considered BACT. Several of the engines currently operation meet the Tier II standards. However, with respect to the non-tier engines, manufacturers design new engines to meet the current Tier standards; existing engines do

not receive retrofits to meet new Tier standards. Therefore, meeting the current Tier standards for the Salt Lake Refinery's emergency engines would require replacing the engines with engines that meet Tier standards. Replacing the engines would constitute "redefining the source," which EPA as a matter of policy does not consider to be BACT. Accordingly, meeting Tier emission standards is not technically feasible for the existing engines that do not currently meet Tier standards.

Option 3: Post Combustion Particulate Matter Control – Catalyst – Technically Feasible

Oxidation catalysts in retrofit applications are widely used for existing engines, such as non-emergency engines subject to the emission limitations of Subpart ZZZZ. Maintenance requirements are typically minimal, and the catalyst life can be up to 15 years in standby engine service.

Economic Feasibility

The economic impact incurred by the use of a pollution control alternative is measured as cost effectiveness. Cost effectiveness is the value obtained by dividing the annual tons of pollutant controlled into the annual cost. This results in a "dollar per ton" effectiveness value used in the economic feasibility analysis. The cost effectiveness calculations for installing oxidation catalysts on the emergency engines were based upon EPA's Air Pollution Cost Control Manual[1]. Based on information obtained from catalyst vendors, the analyses are based on an emission control efficiency of 91%. This analysis used EPA's "default" cost parameters with the following exception:

- The baseline or uncontrolled PM emission rate is defined as the existing engine, with its estimated emission rate in lb /MMBtu; and
- Installation and maintenance of an engine catalyst are low compared to many add-on control devices. Estimated costs of these elements have been reduced from default values.

The following tables present the economic feasibility analysis for oxidation catalyst installation and operation for the emergency diesel engines.

1 EPA Air Pollution Cost Control Manual, 6th ed, EPA 452/B-02-001, Section 4.2.

SUMMARY OF OXIDATION CATALYST COSTS FOR HRFP EMERGENCY ENGINE

Emission Point Number				HRFP Emergency Power
Service				Emergency Generator
Size (HP)				1,676
CAPITAL COSTS:				
Purchased Equipment (PE) [1]				
Catalyst System			$	13,200
Instrumentation(with Monitors)			$	2,000
Freight	10%	% of PE [2]	$	1,320
Sales Tax	6%	% of PE [2]	$	792
Purchased Equipment Cost (PEC)			$	17,312
Direct Installation Costs				
Foundations	0%	% of PEC [2]		N/A
Structure, ductwork ,stack, Fan	15%	% of PEC [2]	$	2,597
Instrumentation (with CEMS)	8%	% of PEC [2]		N/A
Electrical	10%	% of PEC [2]	$	1,731
Piping	0%	% of PEC [2]		N/A
Insulation,lagging for ductwork	0%	% of PEC [2]		N/A
Painting	0%	% of PEC [2]		N/A
Direct Installation Costs			$	4,328
Direct Costs (DC)			$	21,640
Indirect Costs				
Engineering & Project mgmt.	25%	% of PE [2]	$	4,328
Construction and field expenses	0%	% of PE [2]		N/A
Contractor fees	0%	% of PE [2]		N/A
Start-up	10%	% of PE [2]	$	1,731
Performance test	5%	% of PE [2]	$	866
Contingencies	10%	% of DC	$	2,164
Indirect Costs			$	9,089
Total Installed Cost (TIC)			$	30,729
OPERATING COSTS:				
Catalyst Replacement (15-yr lifetime)			$	554
Disposal	35%	% of CR [2]	$	194
Utilities [3]	$0.000	per kW-hr [4]		N/A
Operating labor (None), OP	$ -	per hour [4]		N/A
Supervisory labor, SL (None)	0%	% of OP [4]		N/A
Maintenance labor (None), ML	$ -	per hour [4]		N/A
Maintenance Materials, MM	100%	% of M [4]		N/A
Overhead	40%	% of OP+SL+ML+MM [4]		N/A
Taxes, Insurance, and Admin.	4%	% of TCI [4]	$	1,229
Annual Operating Costs			**$**	**1,978**
Capital Recovery Factor (10%, 20 yr life) Annualized Total Capital Investment [5]	**0.1175**	**x TIC**	**$**	**3,609**
Total Annual Costs			**$**	**5,587**
2015 PM Emissions, Tons/Yr				0.070
CatOx Emissions, Tons/Yr [6]				0.006
PM2.5 Reduction, Tons/Yr				0.063
PM2.5 Cost Effectiveness, $/ton reduced			**$**	**88,185**

Notes:

1) As obtained from discussions with potential vendors, and as compared to the EPA-approved permit applications. SCR Unit cost are ratioed based on heater duty.
2) Typical industry allowances as a percentage of purchased equipment costs; based on experience, engineering practices, discussions with potential vendors, and as compared to the EPA-approved permit applications.
3) Required Utility Cost based assumed average of 0.18 KWH per MMBtu/hr of firing duty.
4) Costs based on experience, engineering practices, and the design for this project.
5) Annualized Total Capital Investment is estimated using the capital recovery factor for 20-yr life and 10 percent average interest; i.e., CRF = (i(1+i)^n)/((1+i)^n)-1).
6) Assumed 90% control efficiency

As identified in the table, the PM Cost effectiveness for catalyst installation is $88,185 per ton of PM//$PM_{10}$/$PM_{2.5}$ abated. This is based on an estimate of the costs to install oxidation catalysts for similar engines. Therefore, Chevron considers the installation of an oxidation catalyst for emergency diesel engines as economically unreasonable for the purposes of $PM_{2.5}$ ambient air quality attainment.

Approximate Cost

Based on estimates for oxidation catalyst installation on the diesel emergency engines, the total installed cost is $30,729. Therefore, oxidation catalyst application for the engines is economically unreasonable.

Implementation Schedule

As noted above, Chevron currently utilizes ULSD fuel, good combustion practices, and routine maintenance for Emergency Diesel Engines. This represents the only technically feasible control option for the non-tier emergency diesel engines.

Other Components Affected (if any)

Not Applicable.

SO_2 BACT Options (Emergency Diesel Engines)

Option 1 - Title: Meet Federal Regulatory Requirements

Description of Option 1: The existing emergency engines must meet the federal requirements under 40 CFR Part 63 Subpart ZZZZ. Units that are subject to a federal NESHAP meet BACT requirements in order to comply with the federal regulations. The engines are required to meet the requirements for emergency engines in Subpart ZZZZ. In addition to other requirements, Subpart ZZZZ restricts operation to the use of ULSD.

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Meet Federal Regulatory Standards – Technically Feasible
Chevron currently combusts only ultra-low sulfur diesel (ULSD) in their emergency engines and utilizes good combustion practices. Additionally, as required by Subpart ZZZZ, Chevron must comply with specified maintenance schedules (crankcase oil, belts and hoses, etc.), and minimize time at idle. A review of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) indicates that previously approved BACT determinations include compliance with applicable federal regulations.

Economic Feasibility

As noted above, Chevron meets the requirements of Subpart ZZZZ, which is the only technically feasible control option for emergency diesel engines, and therefore an economic feasibility analysis is not required.

Approximate Cost

As noted above, Chevron meets the requirements of Subpart ZZZZ, which is the only technically feasible control option for emergency diesel engines, and therefore an economic feasibility analysis is not required.

Implementation Schedule

As noted above, Chevron meets the requirements of Subpart ZZZZ, which is the only technically feasible control option for emergency diesel engines, and therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

NOx BACT Options (Emergency Diesel Engines)

Option 1 - Title: Meet Federal Regulatory Requirements

Description of Option 1: Description of Option 1: The existing emergency engines must meet the federal requirements under 40 CFR Part 63 Subpart ZZZZ. Units that are subject to a federal NESHAP meet BACT requirements in order to comply with the federal regulations. The engines are required to meet the requirements for emergency engines in Subpart ZZZ.

Option 2 - Title: Operate Engine Meeting Tier Nonroad Regulatory Requirements

Description of Option 2: All new engines manufactured in the United States are required to meet emission limits specified in "Tiers," based upon date of manufacture. The current tier is Tier IV. A review of the EPA's RBLC indicates that the use of Tier-compliant engines is BACT for emergency engines. Several of the emergency engines currently operated at Chevron are Tier III engines.

Option 3 - Title: Post Combustion NO_X Control – NSCR Catalyst

Description of Option 3: This technique uses the residual hydrocarbons and CO in the rich-burn engine exhaust as a reducing agent for NOx. In an NSCR system, hydrocarbons and CO are oxidized by O_2 and NOx. The excess hydrocarbons, CO, and NOx pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NOx to N_2. NOx reduction efficiencies can be up to 75 percent, while CO reduction efficiencies are approximately 99 percent.

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Meet Federal Regulatory Standards – Technically Feasible
Chevron currently combusts only ultra-low sulfur diesel (ULSD) in their emergency engines and utilizes good combustion practices. Additionally, as required by Subpart ZZZZ, Chevron must comply with specified maintenance schedules (crankcase oil, belts and hoses, etc.), and minimize time at idle. A review of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) indicates that previously approved BACT determinations include compliance with applicable federal regulations.

Option 2: Operate Engine Meeting Tier Nonroad Regulatory Requirements – Technically Infeasible (for currently Non-Tier Engines)
A review of the EPA's RBLC database for emergency diesel engines indicates that the use of Tier III engines has been considered BACT. Several of the engines currently in operation meet the Tier II standards. However, with respect to the non-tier engines, manufacturers design new engines to meet the current Tier standards; existing engines do not receive retrofits to meet new Tier standards. Therefore, meeting the current Tier standards for the Salt Lake Refinery's emergency engines would require replacing the engines with engines that meet Tier standards. Replacing the engines would constitute "redefining the source," which EPA as a matter of policy does not consider to be BACT. Accordingly, meeting Tier emission standards is not technically feasible for the existing engines that do not currently meet Tier standards.

Option 3 - Title: NSCR – Technically Feasible
The use of NSCR is technically feasible for reducing NO_X emissions (and, as part of the control system, also VOC, PM and CO emissions) from diesel engines. No examples of the use of NSCR on emergency engines were identified in the RBLC, but manufacturers of NSCR systems have indicated that NSCR is in use on emergency diesel engines nationwide.

Economic Feasibility

The economic impact incurred by the use of a pollution control alternative is measured as cost effectiveness. Cost effectiveness is the value obtained by dividing the annual tons of pollutant controlled into the annual cost. This results in a "dollar per ton" effectiveness value used in the economic feasibility analysis. The cost effectiveness calculations for installing oxidation catalysts on the emergency engines were based upon EPA's Air Pollution Cost Control Manual[2]. Based on information obtained from catalyst vendors, the analyses are based on an emission control efficiency of 95%, which is the mid-point of the expected efficiency range obtained from catalyst manufacturers. This analysis used EPA's "default" cost parameters with the following exception:

- The baseline or uncontrolled NO_X emission rate is defined as the existing engine, with its estimated emission rate in lb /MMBtu; and
- Installation and maintenance of an engine catalyst are low compared to many add-on control devices. Estimated costs of these elements have been reduced from default values.

The following tables present the economic feasibility analysis for oxidation catalyst installation and operation for the emergency diesel engines.

2 EPA Air Pollution Cost Control Manual, 6^{th} ed, EPA 452/B-02-001, Section 4.2.

SUMMARY OF OXIDATION CATALYST COSTS FOR HRFP EMERGENCY ENGINE

Emission Point Number				HRFP Emergency Power
Service				Emergency Generator
Size (HP)				1,676
CAPITAL COSTS:				
Purchased Equipment (PE) [1]				
Catalyst System			$	13,200
Instrumentation(with Monitors)			$	2,000
Freight	10%	% of PE [2]	$	1,320
Sales Tax	6%	% of PE [2]	$	792
Purchased Equipment Cost (PEC)			$	17,312
Direct Installation Costs				
Foundations	0%	% of PEC [2]		N/A
Structure, ductwork ,stack, Fan	15%	% of PEC [2]	$	2,597
Instrumentation (with CEMS)	8%	% of PEC [2]		N/A
Electrical	10%	% of PEC [2]	$	1,731
Piping	0%	% of PEC [2]		N/A
Insulation,lagging for ductwork	0%	% of PEC [2]		N/A
Painting	0%	% of PEC [2]		N/A
Direct Installation Costs			$	4,328
Direct Costs (DC)			$	21,640
Indirect Costs				
Engineering & Project mgmt.	25%	% of PE [2]	$	4,328
Construction and field expenses	0%	% of PE [2]		N/A
Contractor fees	0%	% of PE [2]		N/A
Start-up	10%	% of PE [2]	$	1,731
Performance test	5%	% of PE [2]	$	866
Contingencies	10%	% of DC	$	2,164
Indirect Costs			$	9,089
Total Installed Cost (TIC)			$	30,729
OPERATING COSTS:				
Catalyst Replacement (15-yr lifetime)			$	554
Disposal	35%	% of CR [2]	$	194
Utilities [3]	$0.000	per kW-hr [4]		N/A
Operating labor (None), OP	$ -	per hour [4]		N/A
Supervisory labor, SL (None)	0%	% of OP [4]		N/A
Maintenance labor (None), ML	$ -	per hour [4]		N/A
Maintenance Materials, MM	100%	% of M [4]		N/A
Overhead	40%	% of OP+SL+ML+MM [4]		N/A
Taxes, Insurance, and Admin.	4%	% of TCI [4]	$	1,229
Annual Operating Costs			**$**	**1,978**
Capital Recovery Factor (10%, 20 yr life) Annualized Total Capital Investment [5]	**0.1175**	**x TIC**	**$**	**3,609**
Total Annual Costs			**$**	**5,587**
2015 NOx Emissions, Tons/Yr				0.86
NSCR Emissions, Tons/Yr [6]				0.21
NOx Reduction, Tons/Yr				0.64
NOx Cost Effectiveness, $/ton reduced			**$**	**8,689**

Notes:

1) As obtained from discussions with potential vendors, and as compared to the EPA-approved permit applications. SCR Unit cost are ratioed based on heater duty.
2) Typical industry allowances as a percentage of purchased equipment costs; based on experience, engineering practices, discussions with potential vendors, and as compared to the EPA-approved permit applications.
3) Required Utility Cost based assumed average of 0.18 KWH per MMBtu/hr of firing duty.
4) Costs based on experience, engineering practices, and the design for this project.
5) Annualized Total Capital Investment is estimated using the capital recovery factor for 20-yr life and 10 percent average interest; i.e., CRF = (i(1+i)^n)/((1+i)^n)-1).
6) Assumed 90% control efficiency

As identified in the table, the NO_X Cost effectiveness for catalyst installation is \$8,689 per ton of NO_X abated. This is based on an estimate of the costs to install oxidation catalysts for similar engines. Therefore, Chevron considers the installation of a catalyst for emergency diesel engines as economically unreasonable for the purposes of $PM_{2.5}$ ambient air quality attainment.

It is important to note that emissions of $PM_{2.5}$ precursors <u>do not correlate directly to emissions of $PM_{2.5}$</u>. Given the identity of the $PM_{2.5}$ precursors, one might assume at first glance that the photochemically produced part of $PM_{2.5}$ could be controlled simply by decreasing emissions of precursors. In actuality, however, formation of $PM_{2.5}$ sulfate, nitrate, and organic-carbon particles does not depend linearly on their precursors. Minimum formation of $PM_{2.5}$ secondary aerosols occurs when the ratios among NOx, VOC, and SO_2 precursors are least favorable for photochemical interactions. Regrettably, however, the ratios least favorable for secondary aerosol formation are not necessarily optimal for control of ozone formation. Thus, the \$/ton of $PM_{2.5}$ <u>precursor</u> calculated in the economic feasibility analyses cannot be assumed to translate directly to $PM_{2.5}$ \$/ton cost effectiveness. Moreover, NOx and SO_2 emissions from Chevron Salt Lake Refinery sources do not significantly contribute to $PM_{2.5}$ concentrations in the relevant nonattainment areas. Therefore, the actual $PM_{2.5}$ \$/ton cost effectiveness may be **<u>approximately ten (10) times more costly than what was calculated as the \$/ton cost effectiveness for the $PM_{2.5}$ precursor.</u>**

Approximate Cost

Based on estimates for oxidation catalyst installation on the diesel emergency engines, the total installed cost is \$30,729. Therefore, oxidation catalyst application for the engines is economically unreasonable.

Implementation Schedule

As noted above, Chevron currently utilizes good combustion practices and routine maintenance for Emergency Diesel Engines. This represents the only technically feasible control option for emergency diesel engines.

Other Components Affected (if any)

Not Applicable.

VOC BACT Options (Emergency Diesel Engine)

Option 1 - Title: Meet Federal Regulatory Requirements

Description of Option 1: Description of Option 1: The existing emergency engines must meet the federal requirements under 40 CFR Part 63 Subpart ZZZZ. Units that are subject to a federal NESHAP meet BACT requirements in order to comply with the federal regulations. The engines are required to meet the requirements for emergency engines in Subpart ZZZZ.

Option 2 - Title: Operate Engine Meeting Tier Nonroad Regulatory Requirements

Description of Option 2: All new engines manufactured in the United States are required to meet emission limits specified in "Tiers," based upon date of manufacture. The current tier is Tier IV. A review of the EPA's RBLC indicates that the use of Tier-compliant engines is BACT for emergency engines. Several of the emergency engines currently operated at Chevron are Tier III engines.

Option 3 - Title: Post Combustion VOC Control – Oxidation Catalyst

Description of Option 3: The use of a retrofit oxidation catalyst on the engine exhaust can reduce emissions of a number of pollutants, including carbon monoxide (CO), VOC, and PM_{10} and $PM_{2.5}$. Oxidation catalysts can achieve a VOC reduction efficiency up to 90%.

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Meet Federal Regulatory Standards – Technically Feasible
Chevron currently combusts only ultra-low sulfur diesel (ULSD) in their emergency engines and utilizes good combustion practices. Additionally, as required by Subpart ZZZZ, Chevron must comply with specified maintenance schedules (crankcase oil, belts and hoses, etc.), and minimize time at idle. A review of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) indicates that previously approved BACT determinations include compliance with applicable federal regulations.

Option 2: Operate Engine Meeting Tier Nonroad Regulatory Requirements – Technically Infeasible
A review of the EPA's RBLC database for emergency diesel engines indicates that the use of Tier III engines has been considered BACT. Several of the engines currently operation meet the Tier II standards. However, with respect to the non-tier engines,

manufacturers design new engines to meet the current Tier standards; existing engines do not receive retrofits to meet new Tier standards. Therefore, meeting the current Tier standards for the Salt Lake Refinery's emergency engines would require replacing the engines with engines that meet Tier standards. Replacing the engines would constitute "redefining the source," which EPA as a matter of policy does not consider to be BACT. Accordingly, meeting Tier emission standards is not technically feasible for existing engines that do not currently meet Tier standards.

Option 3: Post Combustion VOC Control – Oxidation Catalyst – Technically Feasible

Oxidation catalysts in retrofit applications are widely used for existing engines, such as non-emergency engines subject to the emission limitations of Subpart ZZZZ.

Economic Feasibility

The economic impact incurred by the use of a pollution control alternative is measured as cost effectiveness. Cost effectiveness is the value obtained by dividing the annual tons of pollutant controlled into the annual cost. This results in a "dollar per ton" effectiveness value used in the economic feasibility analysis. The cost effectiveness calculations for installing oxidation catalysts on the emergency engines were based upon EPA's Air Pollution Cost Control Manual[3]. Based on information obtained from catalyst vendors, the analyses are based on an emission control efficiency of 85%, which is the mid-point of the expected efficiency range obtained from catalyst manufacturers. This analysis used EPA's "default" cost parameters with the following exception:

- The baseline or uncontrolled VOC emission rate is defined as the existing engine, with its estimated emission rate in lb /MMBtu.

The following tables present the economic feasibility analysis for oxidation catalyst installation and operation for the emergency diesel engines.

3 EPA Air Pollution Cost Control Manual, 6th ed, EPA 452/B-02-001, Section 4.2.

SUMMARY OF OXIDATION CATALYST COSTS FOR HRFP EMERGENCY ENGINE

Emission Point Number				HRFP Emergency Power
Service				Emergency Generator
Size (HP)				1,676
CAPITAL COSTS:				
Purchased Equipment (PE) [1]				
Catalyst System			$	13,200
Instrumentation(with Monitors)			$	2,000
Freight	10%	% of PE [2]	$	1,320
Sales Tax	6%	% of PE [2]	$	792
Purchased Equipment Cost (PEC)			$	17,312
Direct Installation Costs				
Foundations	0%	% of PEC [2]		N/A
Structure, ductwork ,stack, Fan	15%	% of PEC [2]	$	2,597
Instrumentation (with CEMS)	8%	% of PEC [2]		N/A
Electrical	10%	% of PEC [2]	$	1,731
Piping	0%	% of PEC [2]		N/A
Insulation,lagging for ductwork	0%	% of PEC [2]		N/A
Painting	0%	% of PEC [2]		N/A
Direct Installation Costs			$	4,328
Direct Costs (DC)			$	21,640
Indirect Costs				
Engineering & Project mgmt.	25%	% of PE [2]	$	4,328
Construction and field expenses	0%	% of PE [2]		N/A
Contractor fees	0%	% of PE [2]		N/A
Start-up	10%	% of PE [2]	$	1,731
Performance test	5%	% of PE [2]	$	866
Contingencies	10%	% of DC	$	2,164
Indirect Costs			$	9,089
Total Installed Cost (TIC)			$	30,729
OPERATING COSTS:				
Catalyst Replacement (15-yr lifetime)			$	554
Disposal	35%	% of CR [2]	$	194
Utilities [3]	$0.000	per kW-hr [4]		N/A
Operating labor (None), OP	$ -	per hour [4]		N/A
Supervisory labor, SL (None)	0%	% of OP [4]		N/A
Maintenance labor (None), ML	$ -	per hour [4]		N/A
Maintenance Materials, MM	100%	% of M [4]		N/A
Overhead	40%	% of OP+SL+ML+MM [4]		N/A
Taxes, Insurance, and Admin.	4%	% of TCI [4]	$	1,229
Annual Operating Costs			**$**	**1,978**
Capital Recovery Factor (10%, 20 yr life) **Annualized Total Capital Investment** [5]	**0.1175**	**x TIC**	**$**	**3,609**
Total Annual Costs			**$**	**5,587**
2015 VOC Emissions, Tons/Yr				0.068
CatOx Emissions, Tons/Yr [6]				0.007
VOC Reduction, Tons/Yr				0.061
VOC Cost Effectiveness, $/ton reduced			**$**	**91,235**

Notes:

1) As obtained from discussions with potential vendors, and as compared to the EPA-approved permit applications. SCR Unit cost are ratioed based on heater duty.
2) Typical industry allowances as a percentage of purchased equipment costs; based on experience, engineering practices, discussions with potential vendors, and as compared to the EPA-approved permit applications.
3) Required Utility Cost based assumed average of 0.18 KWH per MMBtu/hr of firing duty.
4) Costs based on experience, engineering practices, and the design for this project.
5) Annualized Total Capital Investment is estimated using the capital recovery factor for 20-yr life and 10 percent average interest; i.e., CRF = (i(1+i)^n)/((1+i)^n)-1).
6) Assumed 90% control efficiency

As identified in the table, the VOC Cost effectiveness for catalyst installation is $91,235 per ton of VOC abated. This is based on an estimate of the costs to install oxidation catalysts for similar engines. Therefore, Chevron considers the installation of an oxidation catalyst for emergency diesel engines as economically unreasonable for the purposes of $PM_{2.5}$ ambient air quality attainment.

It is important to note that emissions of $PM_{2.5}$ precursors do not correlate directly to emissions of $PM_{2.5}$. Given the identity of the $PM_{2.5}$ precursors, one might assume at first glance that the photochemically produced part of $PM_{2.5}$ could be controlled simply by decreasing emissions of precursors. In actuality, however, formation of $PM_{2.5}$ sulfate, nitrate, and organic-carbon particles does not depend linearly on their precursors. Minimum formation of $PM_{2.5}$ secondary aerosols occurs when the ratios among NOx, VOC, and SO_2 precursors are least favorable for photochemical interactions. Regrettably, however, the ratios least favorable for secondary aerosol formation are not necessarily optimal for control of ozone formation. Thus, the $/ton of $PM_{2.5}$ precursor calculated in the economic feasibility analyses cannot be assumed to translate directly to $PM_{2.5}$ $/ton cost effectiveness. Moreover, NOx and SO_2 emissions from Chevron Salt Lake Refinery sources do not significantly contribute to $PM_{2.5}$ concentrations in the relevant nonattainment areas. Therefore, the actual $PM_{2.5}$ $/ton cost effectiveness may be **approximately ten (10) times more costly than what was calculated as the $/ton cost effectiveness for the $PM_{2.5}$ precursor.**

Approximate Cost

Based on estimates for oxidation catalyst installation on the diesel emergency engines, the total installed cost is $30,729. Therefore, oxidation catalyst application for the engines is economically unreasonable.

Implementation Schedule

As noted above, Chevron currently utilizes ULSD fuel, good combustion practices, and routine maintenance for Emergency Diesel Engines. This represents the only technically feasible control option for the non-tier emergency diesel engines.

Other Components Affected (if any)

Not Applicable.

Results of Analysis

The results of the Emergency Diesel Engines BACT Analysis are summarized in the following table.

Pollutant	Control Option	Technically Feasible (Yes/No)	Cost Effectiveness ($/ton)	BACT Selected
$PM_{10}/PM_{2.5}$	Meet Federal Regulatory Standards	Yes	NA	Meet Federal Regulatory Standards
	Meet Federal Tier Requirements	No (for current non-Tier engines)	NA	
	Post Combustion Control (Catalyst)	Yes	$88,185/ton	
SO_2	Meet Federal Regulatory Standards	Yes	NA	Meet Federal Regulatory Standards
NOx	Meet Federal Regulatory Standards	Yes	NA	Meet Federal Regulatory Standards
	Meet Federal Tier Requirements	No (for current non-Tier engines)	$8,689/ton	
	Post Combustion Control (Catalyst)	Yes	No	
VOC/NH_3	Meet Federal Regulatory Standards	Yes	NA	Meet Federal Regulatory Standards
	Meet Federal Tier Requirements	No (for current non-Tier engines)	NA	
	Post Combustion Control (Catalyst)	Yes	$91,235/ton	

Recommended Emission Limits and Monitoring Requirements

As a part of this BACT evaluation, Chevron evaluated emission limitations and monitoring methods that would be appropriate for each pollutant included in the analysis. For the emergency engines, Chevron does not propose any emission limits or monitoring for other pollutants. Meeting Federal regulatory standards and operating with good combustion practices are the most appropriate requirements for these engines.

UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY

MAY 01 2017

DIVISION OF AIR QUALITY

FCC BACT Analysis

1. Site and Company/Owner Name

Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. Description of Facility

Please reference Boiler 1 F11001, Boiler 2 F11002, and Boiler 4 F11004 BACT analysis for a full description of the facility.

3. Recent Permitting Actions (if any)

Chevron replaced its existing electrostatic precipitator in 2009. This reduced actual PM_{10} emissions from the FCC by 75%.

4. Current Emissions (FCC)

For the purposes of this BACT analysis, Chevron has analyzed emissions from the FCC Regenerator at the refinery. Estimated 2015 emissions for FCC Regenerator are presented in the following table.

FCC – 2015 Actual Emissions

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
7.0	7.0	9.4	14.2	0.0	1.8

5. Emission Information / Discussion

Actual 2015 FCC emissions were estimated as follows:

- SO_2, NOx – Emissions calculated from Continuous Emission Monitoring (CEM) data.
- VOC, PM_{10} and $PM_{2.5}$ – Emissions derived from the results of source testing.
- NH_3 – Assumed at twice rate of September 30, 2008 stack test.

<u>PM_{10} and $PM_{2.5}$ BACT Options (FCC Regenerator F32024)</u>

Option 1 - Title: Electrostatic Precipitator (ESP)

Description of Option 1: ESPs use an electrostatic field to charge particulate matter contained in the gas stream. These charged particles then migrate to a grounded collecting surface. The surface is vibrated or rapped periodically to dislodge the particles, and the particles are then collected in a hopper in the bottom of the unit. The control efficiency for ESPs can range from at least 70 to 93 % removal efficiency.

Option 2 - Title: Wet Gas Scrubber

Description of Option 2: There are several different types of wet scrubbing apparatus available. In each case, a water spray is introduced into the exhaust stream, resulting in the cooling and condensing of organic material. The water vapor condenses onto the organic aerosol which then becomes large enough to settle or be removed by cyclonic collectors, filters, or mist eliminators.

The different types of wet scrubbers include:

- Multiple Spray Chambers (usually three to five chambers in series) with a final demisting zone where a high speed centrifugal fan removes droplets;
- Combination Packed Tower and Cyclonic Collector; and
- Wet scrubbers.

Multiple spray chambers, packed towers, and wet scrubbers rely mainly on mass transfer (where gaseous components are dissolved in liquid) and on inertial impaction as removal mechanisms. Wet scrubbers typically obtain an efficiency rate of 95% or greater. The lowest BACT determination found for a wet gas scrubber was 0.3 lb PM / 1,000 lbs coke burned.

<u>Technical Feasibility</u>

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Electrostatic Precipitator – Technically Feasible
Chevron currently employs the use of an ESP to control emissions of the FCC Regenerator F32024. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for FCC Regenerators revealed that this operation has been deemed BACT for these emission sources.

Option 2: Wet Gas Scrubber – Technically Feasible
A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for FCC Regenerators revealed that this operation is considered BACT for these emission sources.

Economic Feasibility

The economic impact incurred by the use of a pollution control alternative is measured as cost effectiveness. Cost effectiveness is the value obtained by dividing the annual tons of pollutant controlled into the annual cost. This results in a "dollar per ton" effectiveness value used in the economic feasibility analysis. The cost effectiveness calculations for installing a wet gas scrubber on FCC Regenerator F32024 were based upon EPA's Air Pollution Cost Control Manual[1].

Chevron currently employs an ESP to control emissions of the FCC Regenerator F32024. Since the technology is already in use, no cost analysis for ESPs is required. Chevron's most recent Method 5F test showed an emission rate of 0.44 lbs / 1,000 lbs coke burned.

The following table presents the economic feasibility analysis for wet gas scrubber installation as Chevron currently employs the use of an ESP to control emissions of the FCC Regenerator F32024.

1 EPA Air Pollution Cost Control Manual, 6th ed, EPA 452/B-02-001, Section 4.2.

SUMMARY OF WET GAS SCRUBBER COSTS FOR FCC REGENERATOR FOR PM10 and PM2.5 CONTROL

Emission Point Number				F32024
Service				FCC Regenerator
CAPITAL COSTS:				
Purchased Equipment (PE) [1]				
Wet Gas Scrubber			$	2,580,761
Ductwork,dampers,stack,Fan			$	793,267
Instrumentation(with CEMS)			$	280,288
Freight	10%	% of PE [2]	$	258,076
Sales Tax	6%	% of PE [2]	$	154,846
Purchased Equipment Cost (PEC)			$	4,067,238
Direct Installation Costs				
Foundations	10%	% of PEC [2]	$	406,724
Structure, ductwork ,stack, Fan	15%	% of PEC [2]	$	610,086
Instrumentation	8%	% of PEC [2]	$	305,043
Electrical	10%	% of PEC [2]	$	406,724
Piping	5%	% of PEC [2]	$	203,362
Insulation, lagging for ductwork	5%	% of PEC [2]	$	203,362
Painting	5%	% of PEC [2]	$	203,362
Direct Installation Costs			$	2,338,662
Direct Costs (DC)			$	6,405,899
Indirect Costs				
Engineering & Project mgmt.	25%	% of PE [2]	$	1,016,809
Construction and field expenses	20%	% of PE [2]	$	813,448
Contractor fees	15%	% of PE [2]	$	610,086
Start-up	10%	% of PE [2]	$	406,724
Performance test	5%	% of PE [2]	$	203,362
Contingencies	10%	% of DC	$	640,590
Indirect Costs			$	3,691,018
Total Installed Cost (TIC)			$	10,096,918
OPERATING COSTS:				
Utilities	$0.066	per kW-hr [3]	$	28,330
Operating labor (0.5 hr / 8 hr shift), OP	$ 25.00	per hour [3]	$	13,688
Supervisory labor, SL	15%	% of OP [3]	$	2,053
Maintenance labor (0.5 hr / 8 hr shift), ML	$ 25.00	per hour [3]	$	13,688
Maintenance Materials, MM	100%	% of M [3]	$	13,688
Overhead	40%	% of OP+SL+ML+MM [3]	$	17,246
Taxes, Insurance, and Admin.	4%	% of TCI [3]	$	403,877
Annual Operating Costs			**$**	**492,568**
Capital Recovery Factor (10%, 20 yr life) **Annualized Total Capital Investment** [4]	**0.1175**	**x TIC**	**$**	**1,185,980**
Total Annual Costs			**$**	**1,678,549**
PM10 Reduction, tons/yr [5]				2.23
PM2.5 Reduction, tons/yr [5]				2.23
PM10 Cost Effectiveness, $/ton reduced			**$**	**753,634**
PM2.5 Cost Effectiveness, $/ton reduced			**$**	**753,634**

Notes:

1) As obtained from discussions with potential vendors, and as compared to the EPA-approved permit applications. Wet Gas Scruber Unit cost are ratioed based on FCC capacity.
2) Typical industry allowances as a percentage of purchased equipment costs; based on experience, engineering practices, discussions with potential vendors, and as compared to the EPA-approved permit applications.
3) Costs based on experience, engineering practices, and the design for this project.
4) Annualized Total Capital Investment is estimated using the capital recovery factor for 20-yr life and 10 percent average interest; i.e., CRF = (i(1+i)^n)/((1+i)^n)-1).
5) Assumes a 0.3 lb / 1,000 lbs coke burn limit as BACT

As identified in the table, the $PM_{10}/PM_{2.5}$ Cost effectiveness for wet gas scrubber installation is \$753,634 per ton of PM_{10} abated and \$753,634 per ton of $PM_{2.5}$ abated. Therefore, Chevron considers the installation of a wet gas scrubber for the FCC as economically unreasonable for the purposes of $PM_{10}/PM_{2.5}$ ambient air quality attainment.

Approximate Cost

Chevron currently employs the use of an ESP to control emissions of the FCC Regenerator F32024.

Based on estimates for wet gas scrubber installation on the FCC, the total installed cost is \$10,096,918. Therefore, wet gas scrubber application for the FCC is economically unreasonable.

Implementation Schedule

Chevron currently employs the use of an ESP to control emissions of the FCC Regenerator F32024.

The installation of a wet gas scrubber is deemed economically unreasonable and so an implementation schedule is not required. However, it is important to note that the installation of wet gas scrubber would require a process unit shutdown in order to perform the work necessary. Thus, the earliest possible time to complete the wet gas scrubber installation would be at the next scheduled major refinery unit turnaround requiring shutdown of the FCC, assuming that the engineering and procurement required could be completed by then.

Other Components Affected (if any)

Not Applicable.

SO_2 BACT Options (FCC Regenerator F32024)

Option 1: Catalyst Additives

Description of Option 1: SO_2 Reducing Additives work by a variety of different mechanisms to capture SO_2 in the regenerator releasing the sulfur as H_2S in the reactor. The SO_2 reducing additive is blended in the FCC catalyst in small amounts in order to change the sulfur balance, carrying the sulfur oxides back to the riser, where they are reduced to H_2S and can be sent to sulfur recovery.

Option 2: Wet Gas Scrubber

Description of Option 2: There are several different types of wet scrubbing apparatus available. In each case, a water spray is introduced into the exhaust stream, resulting in the cooling and condensing of organic material. The water vapor condenses onto the organic aerosol which then becomes large enough to settle or be removed by cyclonic collectors, filters, or mist eliminators.

The different types of wet scrubbers include:

- Multiple Spray Chambers (usually three to five chambers in series) with a final demisting zone where a high speed centrifugal fan removes droplets;
- Combination Packed Tower and Cyclonic Collector; and
- Wet scrubbers.

Multiple spray chambers, packed towers, and wet scrubbers rely mainly on mass transfer (where gaseous components are dissolved in liquid) and on inertial impaction as removal mechanisms. Wet scrubbers typically obtain an efficiency rate comparable to ESPs, 95% or greater. The lowest BACT determination found for wet gas scrubber controls was considered 20 ppm SO_2 on a 365 day average basis.

Option 3: FCCU Feed Hydrotreating

Description of Option 3: Feed Hydrotreating removes sulfur from the FCC unit feed which in turn lowers FCCU precipitator emissions. Feedstock is processed through the hydrocracking unit and gas oil desulfurization prior to being sent to the FCC.

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Catalyst Additives – Technically Feasible

Chevron currently uses SO_2 Reducing Additives in the FCC to reduce emissions. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for FCC regenerators revealed that this operation has been considered BACT for these emission sources.

Option 2: Wet Gas Scrubber – Technically Feasible
A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for FCC regenerators revealed that this operation is considered BACT for these emission sources.

Option 3: FCCU Feed Hydrotreating – Technically Feasible
Chevron currently uses Feed Hydrotreating in combination with Catalyst Additives to reduce FCC SO_2 emissions.

Economic Feasibility

The economic impact incurred by the use of a pollution control alternative is measured as cost effectiveness. Cost effectiveness is the value obtained by dividing the annual tons of pollutant controlled into the annual cost. This results in a "dollar per ton" effectiveness value used in the economic feasibility analysis. The cost effectiveness calculations for installing a wet gas scrubber on FCC Regenerator F32024 were based upon EPA's Air Pollution Cost Control Manual[2].

Chevron currently uses SO_2 Reducing Additives in the FCC to reduce emissions. While Chevron's limit is 25 ppm SO_2 on a 365 day rolling average, actual SO_2 in 2015 was 12 ppm. Therefore no further reductions in SO_2 could be expected by installing a wet gas scrubber which controls to a limit of 20 ppm SO_2.

2 EPA Air Pollution Cost Control Manual, 6th ed, EPA 452/B-02-001, Section 4.2.

SUMMARY OF WET GAS SCRUBBER COSTS FOR FCC Regenerator SO_2 CONTROL

Emission Point Number				F32024
Service				FCC Regenerator
CAPITAL COSTS:				
Purchased Equipment (PE) [1]				
Wet Gas Scrubber			$	2,580,761
Ductwork,dampers,stack,Fan			$	793,267
Instrumentation(with CEMS)			$	280,288
Freight	10%	% of PE [2]	$	258,076
Sales Tax	6%	% of PE [2]	$	154,846
Purchased Equipment Cost (PEC)			$	4,067,238
Direct Installation Costs				
Foundations	10%	% of PEC [2]	$	406,724
Structure, ductwork ,stack, Fan	15%	% of PEC [2]	$	610,086
Instrumentation (with CEMS)	8%	% of PEC [2]	$	305,043
Electrical	10%	% of PEC [2]	$	406,724
Piping	5%	% of PEC [2]	$	203,362
Insulation, lagging for ductwork	5%	% of PEC [2]	$	203,362
Painting	5%	% of PEC [2]	$	203,362
Direct Installation Costs			$	2,338,662
Direct Costs (DC)			$	6,405,899
Indirect Costs				
Engineering & Project mgmt.	25%	% of PE [2]	$	1,016,809
Construction and field expenses	20%	% of PE [2]	$	813,448
Contractor fees	15%	% of PE [2]	$	610,086
Start-up	10%	% of PE [2]	$	406,724
Performance test	5%	% of PE [2]	$	203,362
Contingencies	10%	% of DC	$	640,590
Indirect Costs			$	3,691,018
Total Installed Cost (TIC)			$	10,096,918
OPERATING COSTS:				
Utilities	$0.066	per kW-hr [3]	$	28,330
Operating labor (0.5 hr / 8 hr shift), OP	$ 25.00	per hour [3]	$	13,688
Supervisory labor, SL	15%	% of OP [3]	$	2,053
Maintenance labor (0.5 hr / 8 hr shift), ML	$ 25.00	per hour [3]	$	13,688
Maintenance Materials, MM	100%	% of M [3]	$	13,688
Overhead	40%	% of OP+SL+ML+MM [3]	$	17,246
Taxes, Insurance, and Admin.	4%	% of TCI [3]	$	403,877
Annual Operating Costs			**$**	**492,568**
Capital Recovery Factor (10%, 20 yr life) **Annualized Total Capital Investment [4]**	**0.1175**	**x TIC**	**$**	**1,185,980**
Total Annual Costs			**$**	**1,678,549**
SO_2 Reduction, tons/yr [5]				0.00
SO_2 Cost Effectiveness, $/ton reduced				**n/a - no emission reduction**

Notes:

1) As obtained from discussions with potential vendors, and as compared to the EPA-approved permit applications. Wet Gas Scruber Unit cost are ratioed based on FCC capacity.
2) Typical industry allowances as a percentage of purchased equipment costs; based on experience, engineering practices, discussions with potential vendors, and as compared to the EPA-approved permit applications.
3) Costs based on experience, engineering practices, and the design for this project.
4) Annualized Total Capital Investment is estimated using the capital recovery factor for 20-yr life and 10 percent average interest; i.e., CRF = (i(1+i)^n)/((1+i)^n)-1).
5) Assumes 20 ppm control limit for Scrubber

Chevron currently uses SO_2 Reducing Additives and Feed Hydrotreating in the FCC to reduce emissions. A review of EPA's RBLC database for FCC Regenerators revealed that this operation has been deemed BACT for these emission sources.

As identified in the table, the SO_2 Cost effectiveness for wet gas scrubber installation is undefined since no reduction in emissions is expected. Therefore, Chevron considers the installation of a wet gas scrubber for the FCC as economically unreasonable for the purposes of $PM_{2.5}$ambient air quality attainment.

It is important to note that emissions of $PM_{2.5}$ precursors <u>do not correlate directly to emissions of $PM_{2.5}$</u>. Given the identity of the $PM_{2.5}$ precursors, one might assume at first glance that the photochemically produced part of $PM_{2.5}$ could be controlled simply by decreasing emissions of precursors. In actuality, however, formation of $PM_{2.5}$ sulfate, nitrate, and organic-carbon particles does not depend linearly on their precursors. Minimum formation of $PM_{2.5}$ secondary aerosols occurs when the ratios among NOx, VOC, and SO_2 precursors are least favorable for photochemical interactions. Regrettably, however, the ratios least favorable for secondary aerosol formation are not necessarily optimal for control of ozone formation. Thus, the $/ton of $PM_{2.5}$ <u>precursor</u> calculated in the economic feasibility analyses cannot be assumed to translate directly to $PM_{2.5}$ $/ton cost effectiveness. Moreover, NOx and SO_2 emissions from Chevron Salt Lake Refinery sources do not significantly contribute to $PM_{2.5}$ concentrations in the relevant nonattainment areas. Therefore, the actual $PM_{2.5}$ $/ton cost effectiveness may be **<u>approximately ten (10) times more costly than what was calculated as the $/ton cost effectiveness for the $PM_{2.5}$ precursor.</u>**

<u>Approximate Cost</u>

Chevron currently employs the use of SO_2 Reducing Additives to control emissions of the FCC Regenerator F32024.

Based on estimates for wet gas scrubber installation on the FCC, the total installed cost is $10,096,918. Therefore wet gas scrubber application for the FCC is economically unreasonable.

<u>Implementation Schedule</u>

Chevron currently employs the use of SO_2 Reducing Additives to control emissions of the FCC Regenerator F32024.

The installation of a wet gas scrubber is deemed economically unreasonable and so an implementation schedule is not required. However, it is important to note that the installation of wet gas scrubber would require a process unit shutdown in order to perform the work necessary. Thus, the earliest possible time to complete the wet gas scrubber installation would be at the next scheduled major refinery unit turnaround requiring shutdown of the FCC, assuming that the engineering and procurement required could be completed by then.

<u>Other Components Affected (if any)</u>

Not Applicable.

NOx BACT Options (FCC Regenerator F32024)

Option 1: Feedstock Hydrotreatment

Description of Option 1: Hydrotreatment lowers FCC NOx emissions by reducing the total and basic nitrogen content of the feed. Feedstock is processed through the hydrocracking unit and gas oil desulfurization prior to being sent to the FCC.

Option 2: Catalyst Additives

Description of Option 2: There are two types of catalyst additive that can operate in an FCC to reduce NOx emissions. The first type is a NOx adsorbing catalyst and the second is a low NOx promoter. The second type of additive, such as DeNOx, can be added directly in the promoted inventory and does not require substitution of the platinum promoter. The catalyst additive reduces NOx emissions either by promoting the direct reaction of NO and CO or by acting on the nitrogen intermediates that lead to NOx formation.

Option 3: Selective Catalytic Reduction (SCR)

Description of Option 3: SCR is a post-combustion, flue gas treatment technology that uses ammonia as a reagent to reduce NOx to molecular nitrogen and water in the presence of a metal oxide catalyst. The chemical reactions involved in the SCR process are:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O$$

Catalyst performance is optimized when oxygen level in the exhaust gas stream is above 2 to 3 volume percent. Due to advances in catalyst design, commercial applications of this technology can now operate over an extended temperature range. Precious metal catalysts, such as platinum, can promote oxidation at temperatures as low as 350°F, and zeolite catalysts can operate up to 1,000°F. SCR systems can achieve NOx reduction efficiencies of up to 90 %. To implement SCR control, ammonia (NH_3) storage and handling systems must be installed. Careful control of the ammonia injection and operating parameters must be maintained to limit NH_3 "slip" (emissions of unreacted ammonia) and maintain desired NOx reduction.

Option 4: Low Temperature Oxidation (LoTox)

Description of Option 4: The Low Temperature Oxidation (LoTox) System is a NOx removal system that injects ozone into the flue gas stream to oxidize insoluble NOx to soluble oxidized compounds. Ozone is produced on site and on demand by passing oxygen through an ozone generator. LoTOx is a low temperature system; therefore, it does not require heat input to maintain operational efficiency or to prevent the "slip" of treatment chemicals, such as ammonia, as is common with SCR and SNCR systems.

Ozone is produced in response to the amount of NOx present in the flue gas generated by the process. The low operating temperature allows stable and consistent control regardless of variation in flow, load or NOx content. Ozone rapidly reacts with insoluble NO and NO2 molecules to form soluble N_2O_5. The species $N_2O_5$is highly soluble and will rapidly react with moisture in the gas stream to form nitric acid. The conversion of NOx into the aqueous phase in the scrubber is rapid and irreversible, allowing nearly complete removal of NOx. The nitric acid, along with unreacted N_2O_5nitrous acid formed by reaction of NO_2 with water, can be easily scrubbed out of the gas stream in a wet scrubber with water or neutralized with a caustic solution. LoTox systems can achieve a NOx reduction efficiency of 90% or more.

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Feedstock Hydrotreatment – Technically Feasible
The use of Hydrotreatment is a technically feasible control option and has been confirmed in a review of EPA's RBLC database. Chevron currently has this control option in place.

Option 2: Catalyst Additives – Technically Infeasible
The use of catalyst additives is a technically feasible control option and has been confirmed in a review of EPA's RBLC database. Chevron conducted extensive trials with catalyst additives in Salt Lake as part of its NSR Consent Decree with EPA and found no effect on NO_X emissions.

Option 3: SCR – Technically Feasible
The use of SCR is a technically feasible control option and has been confirmed in a review of EPA's RBLC database. BACT for this technology has been set at 40 ppm per 365 day rolling average.

Option 4: LoTox – Technically Feasible
Although a relatively new technology, LoTox has been implemented in practice for several FCCUs, which was confirmed in a review of EPA's RBLC database. BACT for this technology has been set at 40 ppm per 365 day rolling average.

Economic Feasibility

The economic impact incurred by the use of a pollution control alternative is measured as cost effectiveness. Cost effectiveness is the value obtained by dividing the annual tons of pollutant controlled into the annual cost. This results in a "dollar per ton" effectiveness value used in the economic feasibility analysis. Currently Chevron has a 59 ppm 365 day rolling average limit at its FCC for NO_X. In practice however, Chevron's NOX for 2015 averaged 26 ppm for 2015. Given that BACT for other technologies listed (SCR, and Low Tox) is greater than 26 ppm, no additional emission reductions are expected as shown in the following tables. The cost effectiveness calculations for installing SCR on FCC Regenerator F32024 were based upon EPA's Air Pollution Cost Control Manual[3]. The following table presents the economic feasibility analysis for SCR on FCC Regenerator F32024.

3 EPA Air Pollution Cost Control Manual, 6th ed, EPA 452/B-02-001, Section 4.2.

SUMMARY OF SCR COSTS FOR FCC Regenerator

Emission Point Number			F32024
Service			FCC Regenerator
CAPITAL COSTS:			
Purchased Equipment (PE) [1]			
Third Stage Seperator			$ 469,703
SCR Unit			$ 228,133
Ammonia Skid			$ 211,538
Ammonia Tank			$ 158,653
Ductwork,dampers,stack,Fan			$ 793,267
Instrumentation(with CEMS)			$ 280,288
Freight	10%	% of PE [2]	$ 22,813
Sales Tax	6%	% of PE [2]	$ 13,688
Purchased Equipment Cost (PEC)			$ 1,708,380
Direct Installation Costs			
Foundations	10%	% of PEC [2]	$ 170,838
Structure, ductwork ,stack, Fan	15%	% of PEC [2]	$ 256,257
Instrumentation (with CEMS)	8%	% of PEC [2]	$ 128,128
Electrical	10%	% of PEC [2]	$ 170,838
Piping	5%	% of PEC [2]	$ 85,419
Insulation, lagging for ductwork	5%	% of PEC [2]	$ 85,419
Painting	5%	% of PEC [2]	$ 85,419
Direct Installation Costs			$ 982,318
Direct Costs (DC)			$ 2,690,698
Indirect Costs			
Engineering & Project mgmt.	25%	% of PE [2]	$ 427,095
Construction and field expenses	20%	% of PE [2]	$ 341,676
Contractor fees	15%	% of PE [2]	$ 256,257
Start-up	10%	% of PE [2]	$ 170,838
Performance test	5%	% of PE [2]	$ 85,419
Contingencies	10%	% of DC	$ 269,070
Indirect Costs			$ 1,550,355
Total Installed Cost (TIC)			$ 4,241,053
OPERATING COSTS:			
Catalyst Replacement (5-yr lifetime)			$ 10,471
Disposal	50%	% of CR [2]	$ 5,236
Ammonia (17/46 x tpy NOx removed)	$ 455.00	per ton [4]	$ -
Utilities [3]	$0.066	per kW-hr [4]	$ 16,767
Operating labor (0.5 hr / 8 hr shift), OP	$ 25.00	per hour [4]	$ 13,688
Supervisory labor, SL	15%	% of OP [4]	$ 2,053
Maintenance labor (0.5 hr / 8 hr shift), ML	$ 25.00	per hour [4]	$ 13,688
Maintenance Materials, MM	100%	% of M [4]	$ 13,688
Overhead	40%	% of OP+SL+ML+MM [4]	$ 17,246
Taxes, Insurance, and Admin.	4%	% of TCI [4]	$ 169,642
Annual Operating Costs			**$ 262,477**
Capital Recovery Factor (10%, 20 yr life) **Annualized Total Capital Investment [5]**	**0.1175**	**x TIC**	**$ 498,152**
Total Annual Costs			**$ 760,630**
NOx Reduction, tons/yr [6]			0.00
NOx Cost Effectiveness, $/ton reduced			**n/a - no emission reduction**

Notes:

1) As obtained from discussions with potential vendors, and as compared to the EPA-approved permit applications. SCR Unit cost are ratioed based on FCC capacity.
2) Typical industry allowances as a percentage of purchased equipment costs; based on experience, engineering practices, discussions with potential vendors, and as compared to the EPA-approved permit applications.
3) Required Utility Cost based assumed average of 0.18 KWH per MMBtu/hr of firing duty.
4) Costs based on experience, engineering practices, and the design for this project.
5) Annualized Total Capital Investment is estimated using the capital recovery factor for 20-yr life and 10 percent average interest; i.e., CRF = (i(1+i)^n)/((1+i)^n)-1).
6) Assumed 40 ppm limit per BACT deterimations at other facilities

FCC BACT Analysis

As identified in the table, no NOx reductions are expected. Therefore, Chevron considers the installation of SCR for the FCC as economically unreasonable for the purposes of PM2.5 ambient air quality attainment. Additionally as noted in the heater boiler discussion as well as below, SCR's, while decreasing NO_X, should not be considered BACT for PM2.5 due to increases in NH_3 which is a precursor to secondary PM2.5 formation.

The following table presents the economic feasibility analysis for LoTox on FCC Regenerator F32024. For the purpose of this preliminary analysis, the costs were assumed to primarily result from the installation and operation of the scrubber.

SUMMARY OF LoTox Plus WET GAS SCRUBBER COSTS FOR FCC Regenerator NOx CONTROL

Emission Point Number			F32024
Service			FCC Regenerator
CAPITAL COSTS:			
Purchased Equipment (PE) [1]			
Wet Gas Scrubber			$ 2,951,693
Ductwork,dampers,stack,Fan			$ 793,267
Instrumentation			$ 280,288
Freight	10%	% of PE [2]	$ 295,169
Sales Tax	6%	% of PE [2]	$ 177,102
Purchased Equipment Cost (PEC)			$ 4,497,519
Direct Installation Costs			
Foundations	10%	% of PEC [2]	$ 449,752
Structure, ductwork ,stack, Fan	15%	% of PEC [2]	$ 674,628
Instrumentation	8%	% of PEC [2]	$ 337,314
Electrical	10%	% of PEC [2]	$ 449,752
Piping	5%	% of PEC [2]	$ 224,876
Insulation, lagging for ductwork	5%	% of PEC [2]	$ 224,876
Painting	5%	% of PEC [2]	$ 224,876
Direct Installation Costs			$ 2,586,074
Direct Costs (DC)			$ 7,083,593
Indirect Costs			
Engineering & Project mgmt.	25%	% of PE [2]	$ 1,124,380
Construction and field expenses	20%	% of PE [2]	$ 899,504
Contractor fees	15%	% of PE [2]	$ 674,628
Start-up	10%	% of PE [2]	$ 449,752
Performance test	5%	% of PE [2]	$ 224,876
Contingencies	10%	% of DC	$ 708,359
Indirect Costs			$ 4,081,499
Total Installed Cost (TIC)			$ 11,165,092
OPERATING COSTS:			
Utilities	$0.066	per kW-hr [3]	$ 28,330
Operating labor (0.5 hr / 8 hr shift), OP	$ 25.00	per hour [3]	$ 13,688
Supervisory labor, SL	15%	% of OP [3]	$ 2,053
Maintenance labor (0.5 hr / 8 hr shift), ML	$ 25.00	per hour [3]	$ 13,688
Maintenance Materials, MM	100%	% of M [3]	$ 13,688
Overhead	40%	% of OP+SL+ML+MM [3]	$ 17,246
Taxes, Insurance, and Admin.	4%	% of TCI [3]	$ 446,604
Annual Operating Costs			**$ 535,295**
Capital Recovery Factor (10%, 20 yr life) **Annualized Total Capital Investment [4]**	**0.1175**	**x TIC**	**$ 1,311,447**
Total Annual Costs			**$ 1,846,743**
NOx Reduction, tons/yr [5]			0.00
NOx Cost Effectiveness, $/ton reduced			**n/a - no emission reduction**

Notes:

1) As obtained from discussions with potential vendors, and as compared to the EPA-approved permit applications. Wet Gas Scruber Unit cost are ratioed based on FCC capacity.
2) Typical industry allowances as a percentage of purchased equipment costs; based on experience, engineering practices, discussions with potential vendors, and as compared to the EPA-approved permit applications.
3) Costs based on experience, engineering practices, and the design for this project.
4) Annualized Total Capital Investment is estimated using the capital recovery factor for 20-yr life and 10 percent average interest; i.e., CRF = (i(1+i)^n)/((1+i)^n)-1).
5) Assumed 40 ppm limit per BACT deterimations at other facilities

As identified in the table, no emission reductions would be expected from the installation of LoTox. Therefore, Chevron considers the installation LoTox for the FCC as economically unreasonable for the purposes of PM2.5 ambient air quality attainment.

Chevron already fully hydrotreats the FCC feed to reduce emissions, so no cost effectiveness analysis is needed for that existing technology.

It is important to note that emissions of $PM_{2.5}$ precursors do not correlate directly to emissions of $PM_{2.5}$. Given the identity of the $PM_{2.5}$ precursors, one might assume at first glance that the photochemically produced part of $PM_{2.5}$ could be controlled simply by decreasing emissions of precursors. In actuality, however, formation of $PM_{2.5}$ sulfate, nitrate, and organic-carbon particles does not depend linearly on their precursors. Minimum formation of $PM_{2.5}$ secondary aerosols occurs when the ratios among NOx, VOC, and SO_2 precursors are least favorable for photochemical interactions. Regrettably, however, the ratios least favorable for secondary aerosol formation are not necessarily optimal for control of ozone formation. Thus, the $/ton of $PM_{2.5}$ precursor calculated in the economic feasibility analyses cannot be assumed to translate directly to $PM_{2.5}$ $/ton cost effectiveness. Moreover, NOx and SO_2 emissions from Chevron Salt Lake Refinery sources do not significantly contribute to $PM_{2.5}$ concentrations in the relevant nonattainment areas. Therefore, the actual $PM_{2.5}$ $/ton cost effectiveness may be **approximately ten (10) times more costly than what was calculated as the $/ton cost effectiveness for the $PM_{2.5}$ precursor.**

Approximate Cost

Chevron currently fully hydrotreats the FCC feed to control emissions of the FCC Regenerator F32024.

Based on estimates for SCR installation on the FCC, the total installed cost is $4,241,053. Therefore SCR application for the FCC is economically unreasonable. The estimated installed cost for LoTox is $11,165,092. Therefore LoTox application for NOx control at the FCC is economically unreasonable.

Implementation Schedule

Chevron currently fully hydrotreats the FCC feed to control emissions of the FCC Regenerator F32024.

The installation of SCR is deemed economically unreasonable and so an implementation schedule is not required. However, it is important to note that the installation of SCR would require a process unit shutdown in order to perform the work necessary. Thus, the earliest possible time to complete SCR installation would be at the next scheduled major refinery unit turnaround requiring shutdown of the FCC, assuming that the engineering and procurement required could be completed by then.

Other Components Affected (if any)

In addition to being economically unreasonable, the use of SCR has other substantial Environmental and Energy Impacts. The environmental issues include:

- Use of ammonia reagent, with associated storage, shipping and handling risks;
- Handling and disposal of a degenerated catalyst as a new waste stream;
- Ammonia slip emissions from the system represent a new pollutant emission; and
- Ammonium salt precipitates may increase PM10 and visible plume emissions.

SCR Ammonia Handling Risks

SCR systems typically use either anhydrous ammonia (NH_3 gas) or aqueous ammonia (NH_3 in solution) as the active reagent. Aqueous ammonia reagent is the preferable option due to minimal risks associated with storage and handling compared to anhydrous ammonia. Process design considerations can include abatement approaches as well as mitigation and contingency plans to anticipate and avoid potential incidents.

SCR Catalyst and Hazardous Waste Generation

SCR processes generate a solid chemical waste in the form of spent catalyst that requires treatment and disposal. Since sulfur dioxide will be present in exhaust from the refinery fuel gas-fired units, SCR catalyst fouling is expected to occur at a faster rate than at natural gas-fired installations. Sulfur compounds accelerate catalyst replacement, because fouling generally occurs due to the formation of ammonium bisulfate salts by reaction between SO_2 and ammonia in the catalyst bed. Accumulation of fine solids on the catalyst surfaces accelerates the deterioration of the catalyst, and results in increased pressure drop, reduced efficiency, and more frequent replacement. Upon replacement, the spent catalyst material must be packaged and safely disposed as hazardous waste.

Industry experience with SCR systems at both utility electric generating stations and refineries indicate that the removal and replacement operations can be conducted safely, with insignificant risk to the environment.

SCR Ammonia Slip

Experience indicates that simultaneous, reliable control of ammonia slip (reagent that passes through unreacted) below 10 ppmv, and NOx concentrations below 10 ppmv in the exhaust stream is difficult over the range of operating conditions that occur at a refinery unit.

When SCR catalyst is new and activity is highest, operability is best and the ammonia injection rate can be set to near-stoichiometric levels. As the catalyst ages, its activity decreases. To continuously meet NOx emission limits, the ammonia injection rate must be increased to counteract the less efficient catalyst.

SCR Secondary Byproduct – PM_{10}

Under certain conditions, higher injection rates for ammonia reagent to achieve lower NOx outlet concentrations have been shown to promote formation of secondary particulate, and the phenomenon can be more pronounced as ammonia slip increases. A prime cause of "secondary PM10" formation is the sulfur content in fuel. SCR catalysts effectively oxidize the SO_2 normally present in refinery gas fired heater exhaust to sulfite (SO_3) and sulfate (SO_4). The

SO_3/SO_4 species react with excess ammonia to create extremely fine ammonium bisulfate salt particles that are emitted in the form of secondary PM10 and opacity plumes.

SCR – Energy Impact

In addition to the environmental impacts, there are energy impacts associated with SCR primarily due to increased system pressure drop caused by the SCR catalyst bed. The pressure drop results in elevated back-pressure in the heater, thus increasing its heat rate and electric demand from the burner fan. The EPA has investigated various systems (Alternative Control Techniques Document) and found that the typical efficiency loss due to pressure drop requirements of the SCR catalyst reactor bed is typically 5 to 15% of heat output.

Results of Analysis

The results of the FCC Regenerator F32024 BACT Analysis are summarized in the following table.

Pollutant	Control Option	Technically Feasible (Yes/No)	Cost Effectiveness ($/ton)	BACT Selected
$PM_{10}/PM_{2.5}$	Wet Gas Scrubber	Yes	PM_{10} - $753,634/ton $PM_{2.5}$- $753,634/ton	Proper ESP Design and Operation
SO_2	Wet Gas Scrubber	Yes	No emission reduction	SO_2 Reducing Additives, Feed Hydrotreatment
NOx	Selective Catalytic Reduction (SCR)	No	No emission reduction	FCC Feed Hydrotreatment
	Low Temperature Oxidation (LoTox)	Yes	No emission reduction	

Recommended Emission Limits and Monitoring Requirements

As a part of this BACT evaluation, Chevron has identified emission limitations and monitoring methods that would be appropriate for each pollutant included in the analysis. For the FCC Regenerator F32024, Chevron proposes to comply with the existing and future emission limitations and monitoring requirements of NSPS Subpart J and MACT Subpart UUU, and the requirements of the Consent Decree.

The table below summarizes the proposed emission limits and monitoring requirements.

Pollutant	Source	Proposed Emission Limit	Proposed Monitoring
$PM_{10}/PM_{2.5}$	FCC Regenerator F32024	1 lb Filterable PM/1,000 lb Coke Burn and no more than one 6-minute period per hour greater than 30% Opacity	Continuous Opacity Monitor
SO_2		50 Tons/Year 25 ppmvd @0% O_2 (12 Month) 50 ppmv @0% O_2 (7 day)	Continuous Emission Monitor
NOx		100 Tons/Year 57.8 ppmvd @0% O_2 (365 Day) 106.3 ppmv @0% O_2 (7 day)	Continuous Emission Monitor

Flare 1, 2, 3 BACT Analysis

1. **Site and Company/Owner Name**

   Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. **Description of Facility:**

   Please reference Boiler 1 F11001, Boiler 2 F11002, and Boiler 4 F11004 BACT analysis for a full description of the facility.

3. **Recent Permitting Actions (if any):**

   In 2012 all three of the refinery's flares became applicable to NSPS Ja.

4. **Current Emissions (Flare 1, 2, 3)**

   The flare emissions were estimated based on expected maximum flare flow rates, which were derived from analyses by Chevron's engineers. The emission factors in AP-42 were used to calculate the PTE for NO_X, CO, and VOC. These calculations incorporate the revised VOC emission factor published by EPA in December 2016. The SO_2 PTE was based on the NSPS Subpart Ja annual maximum H_2S content in fuel gas.

   Flares – 2015 Actual Emissions

Flare	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
#1	0.8	0.8	0.8	2.0	4.1	0.0
#2	0.3	0.3	0.3	0.7	1.4	0.0
#3	3.9	3.9	0.04	9.8	20.3	N/A

5. **Emission Information / Discussion**

   Estimated 2015 emissions from the flares were calculated based on the actual flow of gas to the flares, and engineering estimates and the results of source tests.

$PM_{10}/PM_{2.5}/NOx/CO/SO_2/VOC$ BACT Options (Flare)

Option 1 - Title: Meet Federal Regulatory Standards

Description of Option 1: At a minimum, flares that are subject to NESHAP Subpart A (40 CFR 63.11) and NSPS Subpart A (40 CFR 60.18) federal regulations meet BACT requirements in order to comply with the federal regulations. A review of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) indicates that previously approved BACT determinations include compliance with applicable federal regulations.

NESHAP Subpart A and NSPS Subpart A specify the following flare performance standards:

- Steam- or air-assist to improve fuel to air mixing (enhances mixing to ensure complete combustion);
- Supplemental fuel firing to maintain heating value (constant fuel ensures maximum destruction of the waste gas stream); and
- Correct flare design for sufficient discharge velocity (provides a sufficiently large exit velocity to ensure adequate mixing and proper combustion).

In 2015, as part of the Refinery Sector Rule (RSR) regulations, EPA modified the requirements for flares at refineries. Beginning January 30, 2019, flares used as control devices at refineries will be required to meet the following requirements as specified in 40 CFR 63.670 and 671, instead of those in Subpart A of NSPS and NESHAP:

- Operate with a pilot flame at all times;
- Operate without visible emissions, except for 5 minutes during any two hours;
- Maintain a minimum flare tip velocity;
- Combust only gas meeting minimum heating value;
- Install, operate, and maintain monitors for pilot flame, visible emissions, and vent gas flow and composition; and
- Develop a Flare Management Plan and root cause analysis/corrective actions.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Meet Federal Regulatory Standards – Technically Feasible
Chevron currently meets the regulatory control requirements for flares subject to federal NESHAP and/or NSPS. A review of EPA's RBLC indicates that previously approved BACT determinations for flares include compliance with the federal regulatory standards.

As noted above, in the coming years additional operational, monitoring, and planning requirements will apply to flares. Chevron will comply with all of the RSR provisions on or before the applicable dates.

In addition to meeting the applicable federal regulatory standards for flares Chevron Salt Lake Refinery also utilizes flare gas recovery on Flare 1 and 2. Flare 3 is used for the Hydrofluoric Acid Alkylation unit. Because HF acid can be present in the flare system in small amounts, it would pose a reliability threat to recover this flare gas and send it into the refinery's fuel gas system. The fuel gas system would require new engineering design and upgrades to receive this small amount of HF acid, which would be prohibitively a costly endeavor to Chevron. The HF Alky unit off gas is inherently low in sulfur and meets all NSPS J fuel gas requirements.

Economic Feasibility:

As noted above, Chevron currently meets the regulatory control requirements for flares subject to federal NESHAP and/or NSPS which are the only technically feasible control option. Therefore an economic feasibility analysis is not required.

Approximate Cost:

As noted above, Chevron currently meets the regulatory control requirements for flares subject to federal NESHAP and/or NSPS which are the only technically feasible control option. Therefore an economic feasibility analysis is not required.

Implementation Schedule:

As noted above, Chevron currently meets the regulatory control requirements for flares subject to federal NESHAP and/or NSPS which are the only technically feasible control option. Therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

Results of Analysis

The results of the Flares BACT Analysis are summarized in the following table.

Pollutant	Control Option	Technically Feasible (Yes/No)	Cost Effectiveness ($/ton)	BACT Selected
$PM_{10}/PM_{2.5}/$ $NOx/SO_2/VOC$	Meet Applicable Federal Regulatory Standards	Yes	NA	Meet Applicable Federal Regulatory Standards

Recommended Emission Limits and Monitoring Requirements

As a part of this BACT evaluation, Chevron has identified emission limitations and monitoring methods that would be appropriate for each pollutant included in the analysis. For the flares, Chevron will implement all of the applicable monitoring requirements of NSPS and NESHAP standards.

Fugitive Emissions BACT Analysis

1. **Site and Company/Owner Name**

   Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. **Description of Facility:**

   Please reference Boiler 1 F11001, Boiler 2 F11002, and Boiler 4 F11004 BACT analysis for a full description of the facility.

3. **Recent Permitting Actions (if any):**

   The refinery accepted GGGa applicability at all of its process units in 2014.

4. **Current Emissions (Fugitive Emissions)**

   For the purposes of this BACT analysis, Chevron has analyzed potential Fugitive Emissions from Valves, Fittings, Pumps, Compressors, Drains, etc. PTE emissions for these Fugitive Emission sources are presented in the following table.

Fugitive Emissions – 2015 Actual Emissions

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC*	NH_3
N/A	N/A	N/A	N/A	53.7	N/A

* Includes Fugitive Emissions from Boilers, Crude Unit, FCC Unit, Reformer Unit, HF Alkylation Unit, HDS Unit, VGO Hydrotreater Unit, Coker Unit, HDN Unit, Sulfur Recovery Plant, Amine Units and Sour Water Strippers, and Flare Vapor Recovery (excludes tanks and Heavy Liquid VOC's).

5. **Emission Information / Discussion**

   Fugitive Emissions from Valves, Fittings, Pumps, Compressors, Drains, etc. were calculated using LDAR monitoring data and engineering judgment.

Fugitive Emissions BACT Analysis

VOC BACT Options (Fugitive Emissions)

Option 1 - Title: Fugitive Emission Leak Detection and Repair (LDAR) Program

Description of Option 1: The primary control strategy to minimize Fugitive Emissions is an effective LDAR program. The requirements for such programs are defined in the federal and state regulations. An acceptable LDAR program includes a suitable definition of a "leaking" component threshold concentration and repair provisions for leaking components.

Chevron Salt Lake Refinery is also subject to the fugitive emission requirements of EPA Consent Decree No. C 03-04650 CRB which mandates more stringent LDAR requirements than currently required by either federal or state regulations. As part of the EPA Consent Decree, the valve and pump leak definitions are stipulated at 500 and 2000 ppm, respectively. The Consent Decree valve leak definition is more stringent than the federal regulations.

No further control is needed as BACT has been met by implementing the existing LDAR program. The leak definition in the LDAR program is more stringent than previous BACT determinations and existing state and federal regulations.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: LDAR Program – Technically Feasible
Chevron utilizes an approved Fugitive Emission LDAR program. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database revealed that the proper implementation of an approved LDAR program is considered BACT for Fugitive Emissions.

Economic Feasibility:

As noted above, Chevron utilizes an approved Fugitive Emission LDAR program which is the only technically feasible control option. Therefore an economic feasibility analysis is not required.

Approximate Cost:

As noted above, Chevron utilizes an approved Fugitive Emission LDAR program which is the only technically feasible control option. Therefore an economic feasibility analysis is not required.

Fugitive Emissions BACT Analysis

Implementation Schedule:

As noted above, Chevron utilizes an approved Fugitive Emission LDAR program which is the only technically feasible control option. Therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

Results of Analysis

The results of the Fugitive Emission BACT Analysis are summarized in the following table.

Pollutant	Control Option	Technically Feasible (Yes/No)	Cost Effectiveness ($/ton)	BACT Selected
VOC	Fugitive Emission LDAR Program	Yes	NA	Proper LDAR Program Implementation

Recommended Emission Limits and Monitoring Requirements

As a part of this BACT evaluation, Chevron has identified emission limitations and monitoring methods that would be appropriate for each pollutant included in the analysis. Chevron is not proposing any emission limits, or any monitoring beyond the current required LDAR program.

Crude Oil Loading BACT Analysis

1. **Site and Company/Owner Name**

   Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. **Description of Facility:**

   Please reference Boiler 1 F11001, Boiler 2 F11002, and Boiler 4 F11004 BACT analysis for a full description of the facility.

3. **Recent Permitting Actions (if any):**

   In 2014, the refinery received a permit to modify its loading rack to allow for the loading of crude oil.

4. **Current Emissions (Crude Oil Loading)**

   Chevron loads crude oil onto rail cars at a rail car loading rack, which is equipped with a vapor combustion unit (VCU) to reduce VOC emissions. Chevron also conducts loading of low vapor pressure products such as diesel and gasoil onto rail cars and tank trucks. However, loading of these materials does not result in substantial emissions. The racks are also used to unload rail cars and tank trucks, but that operation does not generate emissions at the rack itself; the emissions associated with unloading into storage tanks are included in the storage tank emission calculations. Thus, only the crude oil loading operation will be evaluated in this BACT analysis.

Crude Loading Rack – 2015 Actual Emissions

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
N/A	N/A	N/A	N/A	1.12	N/A

5. **Emission Information / Discussion**

   Estimated 2015 VOC emissions were estimated using Equation 1 in AP-42 Chapter 5.1, and a control efficiency of the VCU of 98 percent.

Crude Oil Loading BACT Analysis

VOC BACT Options for Crude Oil Loading Rack

Option 1 Title: Vapor Combustion Unit (VCU)

Description of Option 1: Chevron operates a VCU at all times when crude oil is being loaded at the Crude Oil Loading Rack. The VCU combusts the VOC emissions evolved from the loading process, using supplemental natural gas as necessary.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Vapor Combustion Unit – Technically Feasible
Chevron currently operates a VCU at the Crude Oil Loading Rack. The VCU is required to achieve a control efficiency of 98 percent, or a VOC emission rate of 10 milligrams per liter of oil loaded. The implementation of crude oil loading, and the installation of the VCU, occurred in 2013. The use of a VCU was determined to be BACT at the time of implementation, and no additional BACT controls have been identified since that time.

Economic Feasibility:

As noted above, Chevron utilizes a VCU for Crude Oil Loading, which is the only technically feasible control option identified, and therefore an economic feasibility analysis is not required.

Approximate Cost:

As noted above, Chevron utilizes a VRU for Crude Oil Loading, which is the only technically feasible control option, and therefore an economic feasibility analysis is not required.

Implementation Schedule:

As noted above, Chevron utilizes a VCU for Crude Oil Loading, which is the only technically feasible control option identified, and therefore an economic feasibility analysis is not applicable.

Other Components Affected (if any)

Not Applicable.

Results of Analysis

The results of the Crude Oil Loading BACT Analysis are summarized in the following table.

Crude Oil Loading BACT Analysis

Pollutant	Control Option	Technically Feasible (Yes/No)	Cost Effectiveness ($/ton)	BACT Selected
VOC/	Vapor Combustion Unit	Yes	NA	Vapor Combustion Unit

<u>Recommended Emission Limits and Monitoring Requirements</u>

As a part of this BACT evaluation, Chevron has identified emission limitations and monitoring methods that would be appropriate for each pollutant included in the analysis. For Crude Oil Loading, Chevron proposes to meet the standards that were determined in the BACT analysis for the implementation of Crude Oil Loading in 2013.

The table below summarizes the proposed emission limits and monitoring requirements.

Pollutant	Source	Proposed Emission Limit	Proposed Monitoring
VOC	Crude Oil Loading	10 mg/liter crude oil loaded 98% VCU Destruction Efficiency	Periodic Stack Testing

Reformer Catalyst Regenerator C35006 BACT Analysis

1. Site and Company/Owner Name

Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. Description of Facility:

Please reference Boiler 1 F11001, Boiler 2 F11002, and Boiler 4 F11004 BACT analysis for a full description of the facility.

3. Recent Permitting Actions (if any):

None

4. Current Emissions (Reformer Catalyst Regenerator C35006)

Chevron Salt Lake Refinery already controls emissions from the catalyst regenerator on the Catalytic Reforming Unit. For catalyst regeneration the unit is taken out of service conducting the following general steps:

- Depressurization, Shutdown, Blinding, Set-up Purging, Regen Start-up
- Carbon (Coke) Burn
- Maintenance Period (no venting)
- Catalyst Rejuvenation/Oxidation 1
- Sulfate Removal
- Catalyst Rejuvenation/Oxidation 2
- Cool Down
- Reduction

Emissions from the depressurizing and purging of the regenerator catalyst are vented to flare for control. Potential emissions from the subsequent steps are controlled using an adsorption scrubber as applicable. Therefore, current emission controls already meet the federal MACT requirements under 40 CFR 63 Subpart UUU (RMACT II) for catalytic reforming units. As such, the Reformer Catalyst Regenerator C35006 has no direct emissions to the atmosphere.

5. Emission Information / Discussion

Not Applicable.

$PM_{10}/PM_{2.5}/SO_2/NO_x/VOC/CO/NH_3$ BACT Options (Reformer Catalyst Regenerator C35006)

Option 1 - Title: Meet Federal Regulatory Standards

Description of Option 1: Reformer Catalyst Regenerator C35006 must meet the federal requirements under 40 CFR Part 63 Subpart UUU. Units that are subject to a federal NESHAP meet BACT requirements in order to comply with the federal regulations. A review of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) indicates that previously approved BACT determinations include compliance with applicable federal regulations.

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Meet Federal Regulatory Standards – Technically Feasible
In order to meet the requirements of 40 CFR 63 Subpart UUU Chevron Salt Lake City Refinery controls the emissions from Reformer Catalyst Regenerator C35006. For catalyst regeneration, potential emissions from the depressurizing and purging of the regenerator catalyst are vented to flare for control. Potential emissions from the subsequent regeneration steps are controlled using an adsorption scrubber as applicable.

Economic Feasibility

As noted above, for catalyst regeneration, potential emissions from the depressurizing and purging of the regenerator catalyst are vented to flare for control. Potential emissions from the subsequent regeneration steps are controlled using an adsorption scrubber as applicable. Therefore, an economic feasibility analysis is not required.

Approximate Cost

As noted above, for catalyst regeneration, potential emissions from the depressurizing and purging of the regenerator catalyst are vented to flare for control. Potential emissions from the subsequent regeneration steps are controlled using an adsorption scrubber as applicable. Therefore, an economic feasibility analysis is not required.

Reformer Catalyst Regenerator C35006 BACT Analysis

Implementation Schedule

As noted above, for catalyst regeneration, potential emissions from the depressurizing and purging of the regenerator catalyst are vented to flare for control. Potential emissions from the subsequent regeneration steps are controlled using an adsorption scrubber as applicable. Therefore, an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

Results of Analysis

The results of the Reformer Catalyst Regenerator C35006 BACT Analysis are summarized in the following table.

Pollutant	Control Option	Technically Feasible (Yes/No)	Cost Effectiveness ($/ton)	BACT Selected
PM_{10}/ $PM_{2.5}$/ SO_2/ NOx/ VOC/ NH_3	Control Reformer Catalyst Regenerator Vent	Yes	NA	Continue Operation Utilizing Control for Reformer Catalyst Regenerator Vent

Recommended Emission Limits and Monitoring Requirements

As a part of this BACT evaluation, Chevron has identified emission limitations and monitoring methods that would be appropriate for each pollutant included in the analysis. For the Catalytic Reformer, Chevron is currently subject to the emission limitations and monitoring requirements stipulated in 40 CFR Part 63, Subpart UUU. As no additional controls were deemed to be feasible, no other limitations or monitoring requirements are proposed.

Pollutant	Source	Process Step	Proposed Emission Limit	Proposed Monitoring
VOC	Reformer Catalyst Regenerator C35006	Initial catalyst depressuring and catalyst purging	Vent emissions to a flare	Monitoring flare pilot flame

Reformer Compressor Engine K35001, K35002, and K35003 BACT Analysis

1. **Site and Company/Owner Name**

   Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. **Description of Facility:**

   Please reference Boiler 1 F11001, Boiler 2 F11002, and Boiler 4 F11004 BACT analysis for a full description of the facility.

3. **Recent Permitting Actions (if any):**

   In 2016, new CO and NOx limits were incorporated into Chevron's Approval Order following the installation of Non-Selective Catalytic Reduction emission controls.

4. **Existing PTE/Allowable Emissions (Reformer Compressor Engine K35001, K35002, and K35003)**

   For the purposes of this BACT analysis, Chevron has grouped Reformer Compressor Engines K35001, K35002, and K35003 (16.0 MMBtu/hr for all three compressors) together. These compressor engines have been grouped together for this BACT analysis based on their similar operation and they are of the same design.

   In 2014, to satisfy the requirements of the Consent Decree between Chevron and EPA, Chevron installed Non-Selective Catalytic Reduction (NSCR) emission controls on all three of the compressor engines, with enforceable exhaust concentration limits for NO_X and CO.

   Chevron has used 2015 actual emissions from each compressor engine individually in this analysis. Estimated emissions for all compressor engines are presented in the following tables.

Reformer Compressor Engines K35001, K35002, and K35003 – 2015 Actual Emissions

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
0.8	0.8	0.02	4.3	1.2	0.02

5. **Emission Information / Discussion**

   NO_X emissions are based on the exhaust concentrations. NH_3 emissions from the refinery's reformer compressor engines were calculated using AP-42 table 5.1-1. All other emissions were estimated using AP-42 Table 3.2-3.

Reformer Compressor Engine K35001, K35002, and K35003 BACT Analysis

PM_{10} and $PM_{2.5}$ BACT Options (Reformer Compressor Engine K35001, K35002, and K35003)

Option 1 - Title: Proper Combustion Engine Design and Operation (Air-to-Fuel Ratio Controls)

Description of Option 1: Proper design and operation of compressor engines will provide the proper air-to-fuel ratio to promote stable combustion essential to maintain low PM emission levels. Additionally, proper combustion practices avoid fuel-rich conditions that may promote soot formation. Good combustion efficiency relies on both hardware design and operating procedures. Automated Air-to-Fuel Ratio (AFR) controls are used to optimize combustion efficiency and emission performance.

Option 2 - Title: Post Combustion Particulate Matter Control - Wet Gas Scrubber or Electrostatic Precipitator (ESP)

Description of Option 2: The use of a wet gas scrubber involves a water spray introduced into the engine exhaust stream, resulting in the cooling and condensing of organic material. The water vapor condenses onto the organic aerosol which then becomes large enough to settle or be removed by cyclonic collectors, filters, or mist eliminators. Wet scrubbers typically obtain an efficiency rate comparable to ESPs of 95% or greater.

ESPs use an electrostatic field to charge particulate matter contained in the gas stream. These charged particles then migrate to a grounded collecting surface. The surface is vibrated or rapped periodically to dislodge the particles, and the particles are then collected in a hopper in the bottom of the unit. The control efficiency for ESPs can range from at least 70 to 93% removal efficiency.

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Proper Combustion Engine Design and Operation (Air-to-Fuel Ratio Controls) – Technically Feasible
Chevron currently combusts only purchased natural gas in their refinery compressor engines and utilizes good combustion practices. Additionally, as noted previously, Chevron operates AFR and NSCR controls on the Reformer Compressor Engine K35001, K35002, and K35003. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for process gas fired compressor engines revealed that proper combustion engine design and operation including the use of AFR and NSCR controls is considered BACT for these emission sources.

Option 2: Post Combustion Particulate Matter Control – Technically Infeasible
A review of the EPA's RBLC database for process gas fired compressor engines revealed that refinery sources listed did not use any post-combustion PM control device to meet BACT standards. Generally, the approved BACT technologies included use of "clean" fuels. Due to the relatively high velocity and volumetric flow rate of the exhaust gas, any type of post-combustion particulate matter control is not technically warranted for gas fired compressor engines.

Economic Feasibility

As noted above, Chevron utilizes proper combustion engine design and operation AFR and NSCR controls for Reformer Compressor Engine K35001, K35002, and K35003. This represents the only technically feasible control option for refinery compressor engines and therefore an economic feasibility analysis is not required.

Approximate Cost

As noted above, Chevron utilizes proper combustion engine design and operation and AFR and NSCR controls for Reformer Compressor Engine K35001, K35002, and K35003. This represents the only technically feasible control option for refinery compressor engines and therefore an economic feasibility analysis is not required.

Implementation Schedule

As noted above, Chevron currently utilizes proper combustion engine design and operation and AFR and NSCR controls for Reformer Compressor Engine K35001, K35002, and K35003. This represents the only technically feasible control option for refinery compressor engines.

Other Components Affected (if any)

Not Applicable.

SO_2 BACT Options (Reformer Compressor Engine K35001, K35002, and K35003)

Option 1 Title: Use of Purchased Natural Gas

Description of Option 1: The purchased natural gas H_2S content is currently limited by the requirements of NSPS Ja and constitutes a low sulfur fuel that will result in minimal SO_2 emissions from the refinery compressor engines.

Option 2 Title: Flue Gas Desulfurization (FGD)

Description of Option 2: FGD is commonly used to control SO_2 from solid fuel-combustion, such as coal. FGD technology is based on a variety of wet or dry scrubbing processes. It has demonstrated control efficiencies of up to 80 percent on coal-fired systems; however, FGD has not been commercially accepted in practice for gas-fired sources.

Option 3 - Title: Wet Gas Scrubber

Description of Option 3: The use of a wet gas scrubber involves a water spray introduced into the compressor engine exhaust stream, resulting in the cooling and condensing of organic material. The water vapor condenses onto the organic aerosol which then becomes large enough to settle or be removed by cyclonic collectors, filters, or mist eliminators.

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Use of Purchased Natural Gas – Technically Feasible
Chevron currently combusts only purchased natural gas in their refinery compressor engines. A review of EPA's RBLC database for process gas fired compressor engines revealed that the use of low sulfur fuel gas is considered BACT for these emission sources.

Option 2 Title: Flue Gas Desulfurization (FGD) – Technically Infeasible
FGD has not been commercially accepted in practice for gas-fired sources. As such, a review of EPA's RBLC database for process gas fired compressor engines revealed that FGD has not been used for refinery compressor engines to meet BACT. Due to the fact that this technology has not been demonstrated in practice for refinery compressor engines largely due to operational complexity of such systems, this technology is deemed technically infeasible.

Option 3: Wet Gas Scrubber – Technically Infeasible
As previously identified, a review of the EPA's RBLC database for process gas fired compressor engines revealed that refinery sources listed did not use any post-combustion wet gas scrubbers to meet BACT standards. Generally, the approved BACT technologies included use of "clean" fuels. Due to the relatively high velocity and volumetric flow rate of the exhaust gas, any type of post-combustion SO_2 control is not technically warranted for gas fired compressor engines.

Economic Feasibility

As noted above, Chevron utilizes purchased natural gas, which is the only technically feasible control option for refinery compressor engines and therefore an economic feasibility analysis is not required.

Approximate Cost

As noted above, Chevron utilizes purchased natural gas, which is the only technically feasible control option for refinery compressor engines and therefore an economic feasibility analysis is not required.

Implementation Schedule

As noted above, Chevron utilizes purchased natural gas, which is the only technically feasible control option for refinery compressor engines and therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

NOx BACT Options (Reformer Compressor Engine K35001, K35002, and K35003)

Option 1 - Title: Proper Combustion Engine Design and Operation (Air-to-Fuel Ratio Controls)

Description of Option 1: Proper design and operation of compressor engines will provide the proper air-to-fuel ratio to promote stable combustion essential to maintain low NOx emission levels. Good combustion efficiency relies on both hardware design and operating procedures. Automated Air-to-Fuel Ratio (AFR) controls are used to optimize combustion efficiency and emission performance.

Option 2 - Title: Nonselective Catalytic Reduction (NSCR)

Description of Option 2: This technique uses the residual hydrocarbons and CO in the rich-burn engine exhaust as a reducing agent for NOx. In an NSCR system, hydrocarbons and CO are oxidized by O_2 and NOx. The excess hydrocarbons, CO, and NOx pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NOx to N_2. NOx reduction efficiencies are usually greater than 90 percent, while CO reduction efficiencies are approximately 90 percent. The NSCR technique is effectively limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke rich-burn turbocharged engines. Engines operating with NSCR require tight air-to-fuel control to maintain high reduction effectiveness without high hydrocarbon emissions. To achieve effective NOx reduction performance, the engine may need to be run with a richer fuel adjustment than normal. This exhaust excess oxygen level would probably be closer to 1 percent. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures.

Option 3 - Title: Selective Catalytic Reduction (SCR)

Description of Option 3: SCR is a post-combustion, flue gas treatment technology that uses ammonia as a reagent to reduce NOx to molecular nitrogen and water in the presence of a metal oxide catalyst. The chemical reactions involved in the SCR process are:

$$4\,NO + 4\,NH_3 + O_2 \rightarrow 4\,N_2 + 6\,H_2O$$
$$6\,NO_2 + 8\,NH_3 \rightarrow 7\,N_2 + 12\,H_2O$$

Catalyst performance is optimized when oxygen level in the exhaust gas stream is above 2 to 3 volume percent. Due to advances in catalyst design, commercial applications of this technology can now operate over an extended temperature range. Precious metal catalysts, such as platinum, can promote oxidation at temperatures as low as 350°F, and zeolite catalysts can operate up to 1,000°F. SCR systems can achieve NOx reduction efficiencies of up to 90 % and reliable NOx emission levels of about 0.0125 lb/MMBtu. To implement SCR control, ammonia (NH_3) storage and handling systems must be installed. Careful control of the ammonia injection and operating parameters must be maintained to limit NH_3 "slip" (emissions of unreacted ammonia) and maintain desired NOx reduction.

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Proper Combustion Engine Design and Operation (Air-to-Fuel Ratio Controls) – Technically Feasible
Chevron currently combusts only purchased natural gas in their refinery compressor engines and utilizes good combustion practices. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for process gas fired compressor engines revealed that proper burner design and operation is considered BACT for these emission sources.

Option 2 - Title: NSCR – Technically Feasible
The use of NSCR is a technically feasible control option and has been confirmed in a review of EPA's RBLC database for specific rich-burn engines. Chevron currently utilizes NSCR controls on the engines.

Option 3 - Title: SCR – Technically Infeasible
The use of SCR for rich-burn engines is a technically infeasible control option. SCR is a post combustion technology that has been shown to be effective in reducing NOx in exhaust from lean-burn engines but is not effective for rich burn engines. For rich-burn engines SCR systems may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed. A review of the EPA's RBLC database for rich-burn engines revealed that refinery sources listed did not use SCR control.

Economic Feasibility

As noted above, Chevron uses purchased natural gas and NSCR, which are the only technically feasible NO_X emission controls for compressor engines, and therefore an economic feasibility analysis is not required.

Approximate Cost

As noted above, Chevron uses purchased natural gas and NSCR, which are the only technically feasible NO_X emission controls for compressor engines, and therefore an economic feasibility analysis is not required.

Implementation Schedule

As noted above, Chevron uses purchased natural gas and NSCR, which are the only technically feasible NO_X emission controls for compressor engines. No new controls will be installed, and therefore an implementation schedule is not required.

Other Components Affected (if any)

Not Applicable.

VOC and NH_3 BACT Options (Reformer Compressor Engine K35001, K35002, and K35003)

Option 1 - Title: Proper Combustion Engine Design and Operation (Air-to-Fuel Ratio Controls)

Description of Option 1: Proper design and operation of compressor engines will provide the proper air-to-fuel ratio to promote stable combustion essential to maintain low VOC and NH_3 emission levels. Additionally, proper combustion practices avoid fuel-rich conditions that may promote soot formation. Good combustion efficiency relies on both hardware design and operating procedures. Automated Air-to-Fuel Ratio (AFR) controls are used to optimize combustion efficiency and emission performance.

Technical Feasibility

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Proper Combustion Engine Design and Operation (Air-to-Fuel Ratio Controls) – Technically Feasible
Chevron currently combusts only purchased natural gas in their refinery compressor engines and utilizes good combustion practices. Additionally, Chevron operates AFR and NSCR controls on the Reformer Compressor Engine K35001, K35002, and K35003. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for process gas fired compressor engines revealed that proper combustion engine design and operation including the use of AFR and NSCR controls is considered BACT for these emission sources.

Economic Feasibility

As noted above, Chevron utilizes proper combustion engine design and operation and AFR and NSCR controls for Reformer Compressor Engine K35001, K35002, and K35003. This represents the only technically feasible control option for refinery compressor engines and therefore an economic feasibility analysis is not required.

Approximate Cost

As noted above, Chevron utilizes proper combustion engine design and operation and AFR and NSCR controls for Reformer Compressor Engine K35001, K35002, and K35003. This represents the only technically feasible control option for refinery compressor engines and therefore an economic feasibility analysis is not required.

Implementation Schedule

As noted above, Chevron utilizes proper combustion engine design and operation and AFR and NSCR controls for Reformer Compressor Engine K35001, K35002, and K35003. These are the only technically feasible controls for compressor engines, and as such an implementation schedule is not needed.

Other Components Affected (if any)

Not Applicable.

Results of Analysis

The results of the Reformer Compressor Engine K35001, K35002, and K35003 BACT Analysis are summarized in the following table.

Pollutant	Control Option	Technically Feasible (Yes/No)	Cost Effectiveness ($/ton)	BACT Selected
$PM_{10}/PM_{2.5}$	Proper Combustion Engine Design and Operation (Air-to-Fuel Ratio Controls)	Yes	NA	Proper Combustion Engine Design and Operation (Air-to-Fuel Ratio Controls) and NSCR*
	Post Combustion Control (WGS or ESP)	No	NA	
SO_2	Use of Low Sulfur Refinery Fuel Gas	Yes	NA	Use of Purchased Natural Gas
	Flue Gas Desulfurization	No	NA	
	Wet Gas Scrubber	No	NA	
NOx	Proper Combustion Engine Design and Operation (Air-to-Fuel Ratio Controls)	Yes	NA	Proper Combustion Engine Design and Operation (Air-to-Fuel Ratio Controls) and NSCR
	Air-to-Fuel Ratio Controls and NSCR	Yes	NA	
	SCR	No	NA	
VOC/NH_3	Proper Combustion Engine Design and Operation (Air-to-Fuel Ratio Controls)	Yes	NA	Proper Combustion Engine Design and Operation (Air-to-Fuel Ratio Controls) and NSCR

Recommended Emission Limits and Monitoring Requirements

As a part of this BACT evaluation, Chevron has identified emission limitations and monitoring methods that would be appropriate for each pollutant included in the analysis. For the compressor engines, Chevron recommends that the NOx limitations and monitoring requirements established in compliance with the Consent Decree. Chevron does not propose any emission limits or monitoring for other pollutants, because NOx is the only pollutant for which Chevron has installed emission controls and thus can maintain control of emission rates.

The table below summarizes the proposed emission limits and monitoring requirements.

Pollutant	Source	Proposed	Proposed

Reformer Compressor Engine K35001, K35002, and K35003 BACT Analysis

		Emission Limit	Monitoring
NOx	K35001	236 ppmvd	Biennial Source Testing
	K35002	208 ppmvd	
	K35003	230 ppmvd	

Note that upon installation of the NSCR controls, Chevron also accepted limits on carbon monoxide (CO) emissions. However, CO is not included in this $PM_{2.5}$ BACT analysis, so these limits are not addressed here.

SRU/TGTU/TGI #1 and SRU/TGTU/TGI #2 BACT Analysis

1. **Site and Company/Owner Name**

   Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. **Description of Facility:**

   Please reference Boiler 1 F11001, Boiler 2 F11002, and Boiler 4 F11004 BACT analysis for a full description of the facility.

3. **Recent Permitting Actions (if any):**

   None

4. **Current Emissions (SRU/TGTU/TGI #1 and SRU/TGTU/TGI #2)**

   For the purposes of this BACT analysis, Chevron has grouped Sulfur Plant #1 SRU/TGTU/TGI #1 and Sulfur Plant #2 SRU/TGTU/TGI #2 together. These sulfur plants have been grouped together for this BACT analysis based on their similar operation and they are of the same design. Both sulfur plants utilize a Tail Gas Treatment Unit (TGTU) and Tail Gas Incinerator (TGI). Estimated 2015 emissions for Sulfur Plant #1 SRU/TGTU/TGI #1 and Sulfur Plant #2 SRU/TGTU/TGI #2 are presented in the following tables.

SRU/TGTU/TGI #1 – 2015 Actual Emissions

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
0.1	0.1	2.9	1.8	0.1	0.1

SRU/TGTU/TGI #2 – 2015 Actual Emissions

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
0.2	0.2	8.2	1.1	0.1	0.1

5. **Emission Information / Discussion**

   Estimated 2015 SO_2 emissions for SRU/TGTU/TGI #1 and SRU/TGTU/TGI #2 were derived from CEMS monitoring data. Emissions of all other pollutants used AP-42 emission factors and the fuel gas consumption rate.

PM_{10}, $PM_{2.5}$, SO_2, NOx, CO, VOC, NH_3, and Benzene BACT Options (SRU/TGTU/TGI #1 and SRU/TGTU/TGI #2)

Option 1 Title: Tail Gas Treatment Unit (TGTU)

Description of Option 1: A single TGTU handles effluent gases from the third stage condensers of both Sulfur Recovery Unit Claus trains. The purpose of this unit, as an effective control of SO_2 emissions, is to convert SO_2 back to H_2S and capture the reduced sulfur compound by amine scrubbing. A preliminary sulfur balance indicates that 99 percent of the sulfur in the TGTU feed stream will be converted to H_2S and recycled. This effectively provides greater than 99 percent control of SO_2 than would be released from the Claus trains alone.

Option 2 - Title: Thermal Oxidizer

Description of Option 2: The Thermal Oxidizer treating effluent gases from the TGTU is a simple design. The fuel source for this combustion activity is a blend of refinery gas, and pipeline natural gas used to help combust SRU off gases. Combustion emissions will be minimized by using proper combustion control and an optimized air-fuel ratio.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Tail Gas Treatment Unit – Technically Feasible
Chevron currently operates a TGTU for the SRUs. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for SRUs revealed that the use of a TGTU is considered BACT for these emission sources.

Option 2: Thermal Oxidizer – Technically Feasible
Chevron uses thermal oxidizers to control emissions from both sulfur recovery plant, and currently combusts low sulfur fuel gas in their refinery thermal oxidizer and utilizes good combustion practices. A review of EPA's RBLC database for process thermal oxidizers revealed that this operation is considered BACT for these emission sources.

Economic Feasibility:

As noted above, Chevron utilizes a TGTU and Thermal Oxidizer for the SRUs which is the only technically feasible control option for refinery SRUs and therefore an economic feasibility analysis is not required.

Approximate Cost:

As noted above, Chevron utilizes a TGTU and Thermal Oxidizer for the SRUs which is the only technically feasible control option for refinery SRUs and therefore an economic feasibility analysis is not required.

Implementation Schedule:

As noted above, Chevron utilizes a TGTU and Thermal Oxidizer for the SRUs which is the only technically feasible control option for refinery SRUs and therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

Results of Analysis

The results of the SRU/TGTU/TGI #1 and SRU/TGTU/TGI #2 BACT Analysis are summarized in the following table.

Pollutant	Control Option	Technically Feasible (Yes/No)	Cost Effectiveness ($/ton)	BACT Selected
$PM_{10}/PM_{2.5}$	Thermal Oxidizer	Yes	NA	Proper Design and Operation
SO_2	Tail Gas Treating Unit and Thermal Oxidizer	Yes	NA	Proper Design and Operation
NOx	Thermal Oxidizer	Yes	NA	Proper Design and Operation
$VOC//NH_3$	Thermal Oxidizer	Yes	NA	Proper Design and Operation

Recommended Emission Limits and Monitoring Requirements

As a part of this BACT evaluation, Chevron has identified emission limitations and monitoring methods that would be appropriate for each pollutant included in the analysis. For SRU/TGTU/TGI #1 and SRU/TGTU/TGI #2, Chevron proposes to comply with the existing limitations and monitoring requirements of MACT Subpart UUU and the requirements of the Consent Decree.

SRU/TGTU/TGI #1 and SRU/TGTU/TGI #2 BACT Analysis

The table below summarizes the proposed emission limits and monitoring requirements.

Pollutant	Source	Proposed Emission Limit	Proposed Monitoring
SO_2	SRU/TGTU/TGI #1 and SRU/TGTU/TGI #2	250 ppmv @0% O2 12hr SRU#1: 88.5 Tons/Yr SRU#2: 97.7 Tons/Yr	Continuous Emission Monitor

Storage Tanks BACT Analysis

1. Site and Company/Owner Name

Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. Description of Facility:

Please reference Boiler 1 F11001, Boiler 2 F11002, and Boiler 4 F11004 BACT analysis for a full description of the facility.

3. Recent Permitting Actions (if any):

None

4. Current Emissions (Storage Tanks)

For the purposes of this BACT analysis, Chevron has grouped all the refinery floating-roof storage tanks together. The refinery also operates a number of fixed-roof tanks that store low vapor pressure stock such as diesel, gasoil, etc. These fixed-roof tanks are not addressed in this analysis, because emission controls have not historically been applied to fixed-roof tanks storing unregulated products. Actual 2015 emissions for all storage tanks at the Chevron Salt Lake refinery are presented in the following table.

Storage Tanks – 2015 Actual Emissions

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
N/A	N/A	N/A	N/A	178.1*	N/A

* VOC emissions are the total for all refinery storage tanks.

5. Emission Information / Discussion

Tank emissions were estimated based upon the actual throughput and other operational information of the tanks using the methodologies presented in AP-42 Chapter 7.1.

VOC/Benzene RACT Options (Storage Tanks)

Option 1 – Install domed roofs on external floating roof tanks

Description of Option 1: Organic liquids with a high vapor pressure are typically stored in floating-roof tanks. The tank may either be an external floating roof (EFR) tank, in which a single roof floats on the surface of the liquid, or an internal floating roof (IFR) tank, in which there is a permanent, external roof, and the floating barrier remains in contact with the liquid, resulting in an open headspace at the top of the tank. Typically, IFR tank emissions are lower than EFR tank emissions, due to the impact of wind and solar heat on the external roof of an EFR.

One method for further reducing emissions from an EFR storage tank is to install a geodesic dome on the open top of the tank, effectively converting it to an IFR tank. The tank cover is in the form of a dome because the tank was typically not designed to support a roof (e.g., internal support columns), so the roof must be self-supporting.

Option 2 - Meet Federal Regulatory Standards

Description of Option 2: At a minimum, storage tanks that are subject to NESHAP and/ or NSPS federal regulations meet BACT requirements in order to comply with the federal regulations. A review of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) indicates that previously approved BACT determinations include compliance with applicable federal regulations.

For tanks requiring controls under federal regulations, the following list identifies potential control options

- Fixed roof (e.g., pressurized dome) tank with a closed vent system and control device;
- Internal floating roof tank with appropriate seal design; and
- External floating roof tank with appropriate seal design.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Install Domes on EFR Tanks – Technically Infeasible
Domes have been installed on EFRs at many sites throughout the country. South Coast Air Quality Management District (SCAQMD) Regulation 1178 required operators at major facilities to retrofit EFRs storing organic liquids with a true vapor pressure (TVP) above 3 psia to retrofit the tanks with domed roofs by 2008.

However, this measure is technically infeasible due to specific local conditions relating to Chevron's EFRs. Much of the refinery's tankfield was built decades ago under now outdated earthquake guidelines. Applying modern standards (an approximately 7.5 seismic event) has required derating a number of tanks in the tank farm (max levels are set artificially low to handle the potential seismic loading). While a detailed engineering study would be required for each tank to determine the precise impacts, on many tanks the foundations and shells would not support the additional weight of the dome plus the required snow load allowance (30 pounds per square foot). Other tanks would be significantly derated. This would require the building of many additional tanks with their own additional air emissions and permitting requirements.

In addition to the technical feasibility discussed above, tank domes (especially in winter climates) could pose significant safety issues. This includes additional confined for entry for required periodic inspections and repairs. Additionally, due to the shape of domed tanks, there is the potential for sudden snow/ice shedding around tank during winter with potential damage to equipment and personnel situated around the tanks. Accordingly, it would be technically infeasible to retrofit the refinery's existing tanks with domes.

Option 2: Meet Federal Regulatory Standards – Technically Feasible
Chevron currently meets the regulatory control requirements for storage tanks subject to federal NESHAP and/or NSPS. A review of EPA's RBLC indicates that previously approved BACT determinations for storage tanks include compliance with the federal regulatory standards.

In addition to meeting the applicable federal regulatory standards for storage tanks Chevron Salt Lake Refinery also takes additional steps to minimize emissions from storage tanks by controlling vapors/emissions from specific tank cleanings/degassing using a thermal oxidizer. The use of a thermal oxidizer to control these emissions is a best practice that exceeds BACT standards for storage tanks.

<u>Economic Feasibility:</u>

As noted above, the installation of domed roofs on Chevron's EFRs is technically infeasible. Further, Chevron currently meets and exceeds the regulatory control requirements for storage tanks subject to federal NESHAP and/or NSPS which are the only technically feasible control option. Therefore an economic feasibility analysis is not required.

<u>Approximate Cost:</u>

As noted above, Chevron currently meets and exceeds the regulatory control requirements for storage tanks subject to federal NESHAP and/or NSPS which are the only technically feasible control option. Therefore an economic feasibility analysis is not required.

Implementation Schedule:

As noted above, the installation of domed roofs on Chevron's EFRs is technically infeasible. Further, Chevron currently meets and exceeds the regulatory control requirements for storage tanks subject to federal NESHAP and/or NSPS which are the only technically feasible control option. Therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

Results of Analysis

The results of the Storage Tanks BACT Analysis are summarized in the following table.

Pollutant	Control Option	Technically Feasible (Yes/No)	Cost Effectiveness ($/ton)	BACT Selected
VOC/Benzene	Install Domed Roof on EFRs	No	NA	Meet Applicable Federal Regulatory Standards
	Meet Applicable Federal Regulatory Standards	Yes	NA	

UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY

MAY 01 2017

DIVISION OF AIR QUALITY

Waste Water Treatment Plant BACT Analysis

1. Site and Company/Owner Name

Chevron Products Company (Chevron) Salt Lake Refinery (Salt Lake Refinery).

2. Description of Facility:

Please reference Boiler 1 F11001, Boiler 2 F11002, and Boiler 4 F11004 BACT analysis for a full description of the facility.

3. Recent Permitting Actions (if any):

None

4. Existing PTE/Allowable Emissions (WWTP)

For the purposes of this BACT analysis, Chevron has analyzed the emissions for the Waste Water Treatment Plant (WWTP). VOC emissions were calculated based on the operation of the regenerative thermal oxidizer (RTO) and the wastewater flow rates. The emissions presented below are from the Induced Air Flotation (IAF) unit, which is controlled by the RTO. Actual 2015 emissions from the WWTP are presented in the following table.

WWTP – 2015 Actual Emissions (Tons/Year)

PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
N/A	N/A	N/A	N/A	9.98	N/A

5. Emission Information / Discussion

Chevron Salt Lake Refinery does not have an API separator, so the factor in AP-42 table 5.1-2 does not apply. The Chevron Salt Lake Refinery collection sump, IAF, and biological contactors are all covered with vapors recovered and destroyed in a Regenerative Thermal Oxidizer (RTO). VOC emissions are calculated based on the RTO control efficiency and wastewater flow rates.

VOC/Benzene BACT Options (WWTP)

Option 1 - Title: Proper WWTP Design

Description of Option 1: Proper design/sizing of the WWTP system will minimize VOC emissions generated. Additionally, the range of available controls for the WWTP is defined by the requirements imposed under federal NSPS Subpart QQQ – Standards of Performance for VOC emissions from Petroleum Wastewater Systems, and NESHAP Subpart FF – Benzene Waste Operations. These standards stipulate VOC vapor capture and control for oil-water separators, wastewater collection systems, and other WWTP vessels that are vented to control devices. In effect, NSPS and NESHAP requirements set the floor for BACT that is to be used for refinery WWTP design.

Option 2 - Title: WWTP Vapor Destruction (Regenerative Thermal Oxidizer)

Description of Option 2: The use of an RTO can further limit VOC emissions from the WWTP. RTOs achieve emission destruction through the process of high temperature thermal oxidation using the proper mix of temperature, residence time, turbulence and oxygen to convert pollutants into carbon dioxide and water vapor.

Technical Feasibility:

This step of the BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Option 1: Proper WWTP Design – Technically Feasible
Chevron's WWTP is currently designed to accommodate all refinery wastewater treatment needs. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database revealed that the proper WWTP design is considered BACT.

Option 2: WWTP Vapor Destruction (RTO) – Technically Feasible
The Chevron Salt Lake Refinery collection sump, IAF, and biological contactors are all covered with vapors recovered and destroyed in an RTO. A review of EPA's RBLC database revealed that the operation of an RTO to control WWTP vapors is considered BACT.

Economic Feasibility:

As noted above, Chevron utilizes a proper WWTP design and an RTO to control WWTP emissions which are the only technically feasible control options. Therefore an economic feasibility analysis is not required.

Waste Water Treatment Plant BACT Analysis

Approximate Cost:

As noted above, Chevron utilizes a proper WWTP design and an RTO to control WWTP emissions which are the only technically feasible control options. Therefore an economic feasibility analysis is not required.

Implementation Schedule:

As noted above, Chevron utilizes a proper WWTP design and an RTO to control WWTP emissions which are the only technically feasible control options. Therefore an implementation schedule is not applicable.

Other Components Affected (if any)

Not Applicable.

Results of Analysis

The results of the WWTP BACT Analysis are summarized in the following table.

Pollutant	Control Option	Technically Feasible (Yes/No)	Cost Effectiveness ($/ton)	BACT Selected
VOC/Benzene	Proper WWTP Design	Yes	NA	Proper Design and Operation
	Regenerative Thermal Oxidizer	Yes	NA	Proper Design and Operation

Recommended Emission Limits and Monitoring Requirements

As a part of this BACT evaluation, Chevron has identified emission limitations and monitoring methods that would be appropriate for each pollutant included in the analysis. For the wastewater treatment plant, Chevron will implement all of the applicable monitoring requirements of NSPS QQQ and NESHAP FF standards that apply to wastewater systems at petroleum refineries.