CHS

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September 30, 2019

Mr. Craig Henrikson
Montana Department of Environmental Quality
Permitting and Compliance Division
P.O. Box 200901
Helena, MT 59620-0901

Re: Requested Regional Haze Four-Factor Analysis for MDEQ Identified Emissions Units

Dear Mr. Henrikson,

In a letter dated April 19, 2019, the MDEQ requested assistance from CHS in developing information for the reasonable progress analysis required as part of developing a State Implementation Plan (SIP) for the second implementation period of the federal Regional Haze program. In response, CHS has prepared a Four-Factor Analysis for control of NOx or SO_2 for each of the emissions units selected by the MDEQ, including the Main Crude Heater (NOx), the Platformer Heater (NOx), Boiler #9 (NOx) and the Main Refinery Flare (SO_2). The attached report includes the Four-Factor Analyses.

Please contact Karen Kennah at Karen.Kennah@chsinc.com or 406/855-5169 if there are any questions or additional information is needed.

Sincerely,

Patrick B Kimmet

Patrick B. Kimmet
Vice President, Laurel Refinery

Attachment

Requested Regional Haze Four-Factor Analysis for MDEQ Identified Emissions Units

CHS Inc.
Laurel, Montana

September 2019

1.0 Introduction

In a letter dated April 19, 2019, the Montana Department of Environmental Quality (MDEQ) requested assistance from CHS in developing information for the reasonable progress analysis required as part of the process of developing a State Implementation Plan (SIP) for the second implementation period of the federal Regional Haze program ending in 2028.

As part of the reasonable progress analysis, the MDEQ is working with the Western Regional Air Partnership (WRAP) to prepare regional air quality modeling of visibility impacts associated with current emissions, projected future emissions, and potential future control scenarios. Section 2 of this report summarizes the Laurel Refinery's emissions information that CHS provided to the MDEQ for use in this analysis.

Development of the potential future control scenarios will require the MDEQ to assess potential emission control technologies for selected sources against four factors: cost of controls, time necessary to install the controls, energy and non-air quality impacts, and remaining useful life of the source under evaluation.[1] This analysis is referred to as a "Four-Factor Analysis." Section 3 of this report contains the Four-Factor Analysis that was performed for each of the emission unit/pollutant combinations selected by the MDEQ.

In the selection of reasonable controls for Regional Haze, the MDEQ will consider the results of the Four-Factor Analysis along with the visibility benefits associated with the potential emissions controls. The MDEQ may also consider the following additional factors[2] in determining which controls are necessary to make reasonable progress toward visibility goals:

- Emissions reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
- Measures to mitigate the impacts of construction activities;
- Source retirement and replacement schedules;
- Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs; and

[1] The four factors are derived from the statutory factors: cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance, and remaining useful life. See 42 U.S.C. § 7491(g)(1).

[2] Section 51.308(f)(2)(iv) of the Regional Haze Rule requires that when developing its long term strategy (LTS) a state must consider five additional factors.

- The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

Each Four-Factor Analysis includes a summary of CHS's conclusions and a discussion regarding consideration of the other factors.

2.0 Laurel Refinery Emissions Information

As noted, CHS provided emissions information to the MDEQ to be used in the regional airshed modeling used to determine visibility impacts associated with current emissions, projected future emissions, and potential future control scenarios.

The "current emissions" scenario is based on baseline emissions information provided by each facility included in the MDEQ analysis. For the CHS Laurel refinery, the average of the 2017 and 2018 actual emissions was selected as the representative baseline emissions. This was based primarily on two factors related to the main refinery flare. First, flare emissions have been more accurately quantified since installation of flare gas flow and composition monitors at the end of 2015. Second, emissions from this time period account for emissions reductions achieved with the installation of the refinery's flare gas recovery system (FGRS).

The "projected future emissions" analysis incorporates changes in emissions between the baseline and 2028 that are anticipated to result from non-Regional Haze rules and regulations or other factors that are already in place or anticipated. This scenario is referred to as the 2028 on-the-books/on-the-way (OTB/OTW) scenario. For the CHS Laurel Refinery, adjustments to the 2017-2018 representative baseline for the 2028 OTB/OTW scenario were identified for the following emissions units:[3]

- Platformer Recycle Compressor: The natural gas fired driver for this compressor was replaced with an electric motor during 2018. This resulted in a reduction in NOx emissions from the 2017-2018 baseline.
- #2 Crude Unit Vacuum Heater: This refinery fuel gas (RFG) fired process heater is nearing the end of its serviceable life. It will be replaced prior to 2028 with a heater that includes ultra-low NOx burners. This will result in a reduction in actual NOx emissions from the 2017-2018 baseline.
- Stationary Emergency Engines: Emissions from stationary emergency engines were first added to the refinery emissions inventory in 2018. A small increase in actual NOx emissions from the 2017-2018 baseline will result because they were not reported in 2017.
- Main Refinery Flare: It is conservatively estimated that SO_2 emissions from the main refinery flare will decrease by 20% from the 2017-2018 baseline by 2028 as a result of ongoing air pollution control programs, including optimization and

[3] As provided to the MDEQ in an email dated 7/22/2019. Note that CHS has since made the decision to repair rather than replace the NHT Splitter Heater. As a result, the associated minor NOx reduction included in the 2028 OTB/OTW scenario should no longer be included.

increased utilization of the FGRS and the ongoing work practices required by applicable regulations.

The "potential future control" modeling scenarios will incorporate changes in emissions that may result from the addition of selected reasonable controls for Regional Haze. These changes will be based on the MDEQ's review of the Four-Factor Analyses for all Montana sources included in the study along with their consideration of other factors.

3.0 Four-Factor Analysis

3.1. Four-Factor Analysis Overview

In accordance with the requirements of 40 CFR 51.308(f)(2)(i), the MDEQ must consider four statutory factors when evaluating and determining the emissions reduction measures from the emissions units located at a source that are necessary to make reasonable progress towards achieving natural visibility conditions. The four statutory factors are as follows:

1) The costs of compliance;
2) The time necessary for compliance;
3) The energy and non-air quality environmental impacts of compliance; and
4) The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

The first step in characterizing the control measure for a given emissions unit is to identify the technically feasible control measures for those pollutants that contribute to visibility impairment.[4] Once the set of technically feasible control measures is determined, the four factors used to determine if a given control measure should be selected must be characterized.

A brief description of what is considered a technically feasible control and each of the four statutory factors along with EPA's recommendations for evaluating each of the factors is provided below.

3.1.1 Technical Feasibility

For purposes of this report, a control measure/technology is considered technically feasible if it has been previously installed and operated successfully at a similar emissions source, or there is technical agreement that the technology can be applied to the emissions source. Technical infeasibility is demonstrated through clear physical, chemical, or other engineering principles that demonstrate that technical difficulties preclude the successful use of the control option.

The technology must be commercially available for it to be considered a candidate. Technologies which have not yet been applied to (or permitted for) full scale operations

[4] *Guidance on Regional Haze, op. cit.,* page 28.

are not considered available. A source should be able to purchase or construct a process or control device that has already been demonstrated in practice.[5]

In general, if a control technology has been "demonstrated" successfully for the type of emission source, then it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine whether the control technology is technical feasibility.[6]

Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." A technology is considered "available" if it can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.[7]

Applicability involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emissions source), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emissions source may not be applicable to a similar source depending on differences in physical and chemical characteristics of the gas stream. Note that vendor guarantees alone do not constitute technical availability. The 1990 Draft Workshop Manual states the following:[8]

> Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique. However, a vendor guarantee alone is not considered to be sufficient justification that a control option will work. There are many instances where vendor guarantees for emissions control equipment have not been met.

3.1.2 Costs of Compliance

Cost estimates have been developed for each technically feasible control option. Costs include the total capital costs to engineer, design, procure, and install the control technology, and annual operating and maintenance (O&M) costs. O&M costs include both fixed and variable O&M. Fixed O&M includes costs that are independent of control system operation and would be incurred even if the control system were shut down. Fixed O&M includes categories such as operating and maintenance labor, administrative

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[5] New Source Review Workshop Manual, Draft 1990, page B-12.
[6] *Ibid* page B.17.
[7] *Ibid* page b.17.
[8] *Ibid* page B.20.

charges, property taxes, and insurance. Variable O&M includes the cost of consumables, including reagent (e.g. lime or limestone, ammonia, urea, etc.), by-product management, water consumption, and electric power requirements associated with operating the control system. For existing facilities, O&M cost estimates should represent the control option's incremental increase over current O&M costs.

Capital costs include all costs required to engineer, design, procure, and install equipment needed for the control system. The accounting principles described in Chapter 2 of Section 1 of EPA's Air Pollution Control Cost Manual (the "Control Cost Manual") have been used when calculating control system costs for a four-factor analysis.

Section 2.3 of the Control Cost Manual (Section 1, Chapter 2) describes the cost categories generally used to calculate the total capital cost of a retrofit control technology. Cost categories include total capital investment (TCI), which is defined to "include all costs required to purchase equipment needed for the control systems (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs)." Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (*i.e.,* cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies. The total annual cost (TAC) of a control option includes the annualized capital recovery cost plus the total annual O&M costs. Consistent with the Control Cost Manual, the TAC is determined by applying a capital recovery factor (CRF) to the total capital investment.

The TAC for each control option ($/yr) is divided by the total annual emissions reduction (tpy) to determine the control option's average cost-effectiveness on a $/ton basis. Emissions reductions are calculated based on the difference between baseline annual emissions and post-control annual emissions. To define the post control emissions, the control effectiveness of a given control is based on technical input from experts familiar with the retrofit of a particular control within the subject source (*i.e.,* ultra-low NOx burners in an existing process heater or boiler).

3.1.3 Time Necessary for Compliance

EPA's BART Guidelines recommend that prior experiences with the planning and installation of new emission controls are the best guide to how much time a particular source will reasonably need for compliance. However, source-specific factors including the time necessary to engineer, procure, and install an available, technically feasible control option and how those activities fit within a given process unit's scheduled turnarounds and turnaround durations are considered.

3.1.4 Energy and Non-Air Quality Environmental Impacts of Compliance

Characterizing the energy and non-air environmental impacts generally involves assessing the impact of a control measure on the energy consumed by a source. Non-air environmental impacts can include the generation of wastes for disposal and impacts on other environmental media, such as nearby water bodies. The Control Cost Manual provides guidance on estimating energy requirements or savings for some situations. For purposes of this analysis, the direct energy impacts are quantified in terms of kilowatt-hours or the amount of additional fuels usage. This report characterizes where there is a significant potential non-air environmental impact.

3.1.5 Remaining Useful Life

Generally, this factor is accounted for by considering the useful life of the control system rather than the source. The remaining useful life of the emissions unit is usually longer than the useful life of the emissions control system under review. As a result, it is assumed that after the end of the useful life of the emissions control, it will be replaced by a like control. Thus, the annualized compliance costs for that control is typically based on the useful life of the control equipment rather than the life of the source. That is the case for each of the controls considered by this analysis.

3.2. Four-Factor Analyses

For the CHS Laurel Refinery, the MDEQ requested that a Four-Factor Analysis be developed and submitted by September 30, 2019, for either NOx or SO_2 for the four emissions units presented in Table 3-1. This section contains the Four-Factor Analysis that was performed for each of the identified emissions unit/pollutant combinations. The analyses presented are intended to be used in developing the long-term strategy under the Regional Haze program. The end of each analysis includes a summary of CHS's conclusions and a discussion of additional factors, if applicable, to be considered by DEQ in the selection of future controls for Regional Haze.

Table 3-1. Summary of CHS Emission Units Covered by the Analysis

Source	Pollutant	2017-2018 Baseline, TPY
Main Crude Heater	NOx	43.6
Platformer Heater	NOx	91.4
#9 Boiler	NOx	29.3
Main Refinery Flare	SO_2	181.6

3.2.1 Process Heaters and Boilers

As shown in Table 3-1, the MDEQ requested that CHS complete a four-factor analysis for the control of NOx on the following sources:

- Main Crude Heater
- Platformer Heater
- Boiler #9

The following is a brief description of each emissions unit followed by the four-factor analysis for NOx from these units.

The Main Crude Heater was installed in 1961 and is located in the #1 Crude Unit. It is a natural draft horizontal cabin type heater with a top mounted convection section and stack and has been retrofitted with an air pre-heat system. It is equipped with 24 burners located along the sidewalls that fire horizontally along the floor of the firebox. It has a design heat input of 142 MMBtu/hr (HHV) and is fired with RFG. In 2012, the burners were replaced with low NOx burners that had a burner vendor guaranteed NOx emissions rate of 0.08 lb/MMBtu(HHV). Because the heater does not have CEMs and stack testing has not been required, a NOx emission rate of 0.1 lb/MMBtu(HHV) has been conservatively used as the basis for emissions calculations since completion of the 2012 burner retrofit.

The Platformer Heater was installed in 1973 and is located in the Platformer Unit. It is a natural draft, four cell heater with a common convection section that generates steam. There are 36 burners fired horizontally in three cells from both end walls (12 burners per cell) and six (6) floor fired burners in the fourth cell. It has a design heat input of 190.4 MMBtu/hr (HHV) and is fired with RFG. The NOx emission rate from the heater has been conservatively assumed to be equal to the AP-42 emissions factor of 280 lb/10^6 scf (approximately 0.275 lb/MMBtu, HHV) for large wall-fired boilers.[9] A performance test completed in 2002 indicated an actual NOx rate of 0.163 lb/MMBtu.

[9] See AP-42, Fifth Edition, Table 1.4-1.

Boiler #9 is one of four steam generating boilers located at the Laurel refinery. It was installed in 1978. It is a natural gas fired unit with one burner and has a design heat input of 98 MMBtu/hr (HHV). The assumed NOx emissions rate from the boiler is based on the AP-42 emission factors of 100 lb/10^6 scf (approximately 0.098 lb/MMBtu, HHV) for small boilers.[10]

3.2.2 Four-Factor Analysis Process Heater NOx

Nitrogen oxides are formed as part of the combustion process and are generally classified in accordance with their formation mechanism as either thermal NOx or fuel NOx. Thermal NOx is formed by the thermal dissociation and subsequent reaction of the nitrogen and oxygen in the combustion air at high temperature. The amount of thermal NOx formation is a function of the heater/boiler burner design, flame temperature, residence time at flame temperature, and fuel/air ratios in the primary combustion zone. The rate of thermal NOx formation increases exponentially with the flame temperature.

Fuel NOx is formed by the gas-phase oxidation of nitrogen that is chemically bound (*i.e.,* CN compounds) in the fuel (*i.e.,* char nitrogen). Fuel NOx formation is largely independent of combustion temperature and the nature of the organic nitrogen compound. Its formation is dependent on fuel nitrogen content and the amount of excess combustion air (*i.e.,* the excess oxygen beyond the fuel's stoichiometric requirement). Refinery gas and natural gas contain negligible amounts of fuel bound nitrogen. As a result, the predominant type of NOx that is formed in refinery process heaters/boilers is thermal NOx.

Control of the air/fuel stoichiometry is critical to the control of thermal NOx. Thermal NOx formation also decreases rapidly as the combustion temperature drops below the adiabatic flame temperature for a given stoichiometry. Maximum reduction of thermal NOx is achieved by simultaneous control of both combustion temperature and air/fuel stoichiometry. Ultra-low NOx burner (ULNB) technologies work to control both combustion temperature and air/fuel stoichiometry. This is in part accomplished by extending the flame length such that combustion temperatures are lower, and the air/fuel stoichiometry can be controlled during the combustion process. As a result, some classes of existing process heaters where there is inadequate space to accommodate the increase in flame length are inherently poor candidates for the retrofit of ULNB technology.

[10] *See* AP-42, Fifth Edition, Table 1.4-1.

3.2.2.1. Potentially Available NOx Control Technologies

Based on a review of recent NOx control precedents for gas fired process heaters two fundamental categories of NOx controls were identified: low NOx burners (LNB) or ULNB, and post-combustion catalytic control to selectively reduce NOx emissions (referred to as selective catalytic reduction or SCR). In addition to these controls, external flue gas recirculation (FGR) was identified as a potential NOx control for boilers. As noted below, the NOx control effectiveness of ULNB technology makes use of what is called internal FGR.

Additional controls that are applied to the control of NOx from other types of combustion sources include: selective noncatalytic reduction (SNCR), nonselective catalytic reduction (NSCR), and EMx™. These controls, which are potentially applicable via technology transfer, are also considered.

3.2.2.2. Technical Feasibility of Available NOx Control Technologies

LNBs/ULNB, and SCR are considered to be demonstrated on gas fired refinery process heaters. In addition to LNBs/ULNB, and SCR, FGR is also considered demonstrated on boilers. As a result, these controls are considered further by this analysis. The technical feasibility of FGR to process heaters, and SNCR, NSCR, and EMx™ to both process heaters and boilers are evaluated further using the previously discussed criteria: applicability, availability, and demonstrated in practice.

Flue Gas Recirculation (FGR): FGR is commonly employed on gas fired boilers. This technology takes flue gas from the boiler exhaust and using a fan recirculates a portion of the flue gas back into the boiler furnace near the burners. FGR reduces thermal NO_X generation by reducing the concentration of oxygen in the burner flame region, and by providing more mass in the burner zone, which reduces the overall combustion temperature. There are two forms of FGR: external and internal. The NOx control mechanism and the effect of FGR on boiler performance for both forms, internal and external, are identical. The only difference between internal and external FGR is in the mechanics of introducing flue gas into the furnace near the burner.

External FGR takes flue gases after heat recovery has been accomplished and recirculates a portion of the flue gas back to the burner combustion zone. To accomplish this, an external fan and ductwork is required to move the flue gas into the combustion zone. External FGR is primarily used for natural gas-fired boilers. Unlike petroleum refinery process heaters, gas fired boilers less than 500 mmBtu/hr heat input have few burners (one to four) that are co-located and coupling the externally recirculated flue gas with the limited number of co-located burners is not difficult. Implementation of external FGR to an uncontrolled boiler is capable of achieving a NOx reduction of 60 percent.[11]

Internal FGR is accomplished by recirculating the flue gases coming off of the burner flame back into the base of the burner flame. Internal FGR is accomplished by the burner design. Burners using internal FGR are referred to as ultra LNB (ULNB). To better control the process tube skin temperatures and prevent coking of the process hydrocarbons in the tubes, petroleum refinery process heaters have many small burners. The use of ULNB is considered technically feasible. External FGR has not been applied to process heaters because the technically feasible NOx reductions are minimal when compared to ULNBs which use internal FGR.

Selective Noncatalytic Reduction (SNCR): SNCR is a post-combustion NOx control technology in which a selective reagent, either ammonia or urea, is injected into the exhaust gases to react with NOx, forming elemental nitrogen and water without the use of a catalyst. This process is effective in reducing NOx emissions within specific constraints, requiring uniform mixing of the reagent into the flue gas within a zone of the exhaust path where the flue gas temperature is within a narrow temperature range of approximately 1600 to 2000°F. To achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window must be at least one half second. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range the reagent will convert to NOx and below the lower end of the temperature range the desired chemical reactions will not proceed and the injected reagent will be emitted as ammonia slip. Implementation of SNCR to an uncontrolled boiler is capable of achieving a NOx reduction of 40 to 60 percent.

Because SNCR's ability to achieve NOx reduction requires operation of the combustion source within specific ranges it has previously only been applied to the control of NOx emissions from sources that operate within well-defined operating ranges and that do not rapidly vary across those ranges such as base-loaded boilers and FCCUs. Refinery process heaters operate across much wider ranges. As a result, SNCR has not been widely applied within the refinery industry and is not considered feasible for the process heaters. Boiler #9 is operated over a wide range of loads. As a result, SNCR is eliminated from further consideration.

Nonselective Catalytic Reduction (NSCR). NSCR is used to reduce NOx emissions in the exhaust of automotive engines and stationary internal combustion engines. NSCR

[11] *See* AP-42: Compilation of Air Emissions Factors Table 1.4-1.

systems are comprised of three different catalyst types used in series. The first catalyst in the series is a reducing catalyst that is used to react unburned hydrocarbon in the exhaust with NOx in the exhaust. Tuning the engine to run fuel rich creates the unburned hydrocarbon. The next catalyst in the series is an oxidizing catalyst that is used to oxidize the unburned fuel to CO and water and the final catalyst, which is also and oxidizing catalyst is used to oxidize any remaining CO. NSCR has only been applied to engines because it is impractical to tune a fired combustion source such as a process heater to combust in a fuel rich manner. As a result, this control type is considered to be infeasible for the proposed application and removed from further review.

EMx™: The EMx™ system (formerly referred to as SCONOX™) is an add-on control device that simultaneously oxidizes CO to CO_2, VOCs to CO_2 and water, NO to NO_2 and then adsorbs the NO_2 onto the surface of a potassium carbonate coated catalyst. The EMx™ system does not require injection of a reactant, such as ammonia, as required by SCR and SNCR and operates most effectively at temperatures ranging from 300°F to 700°F. The overall chemical reaction between NO_2 and the potassium carbonate catalyst is as follows:

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3$$

The catalyst has a finite capacity to react with NO_2. As a result, to maintain the required NOx/NO_2 removal rate, the catalyst must be periodically regenerated. Regeneration is accomplished by passing a reducing gas containing a dilute concentration of hydrogen across the surface of the catalyst in the absence of oxygen. Hydrogen in the regeneration gas reacts with the nitrites and nitrates adsorbed on the catalyst surface to form water and molecular nitrogen. Carbon dioxide in the regeneration gas reacts with the potassium nitrite and nitrates to form potassium carbonate, the original form of the chemical in the catalyst coating. The overall chemical reaction during regeneration is as follows:

$$KNO_2 + KNO_3 + 4H_2 + CO_2 \rightarrow K_2CO_3 + 4H_2O + N_2$$

The regeneration gas is produced in a gas generator using a two-stage process to produce molecular hydrogen and carbon dioxide. In the first stage, natural gas and air are reacted across a partial oxidation catalyst to form carbon monoxide and hydrogen. Steam is added to the mixture and then passed across a low temperature shift catalyst, forming carbon dioxide and more hydrogen. The regeneration gas mixture is diluted to less than four percent hydrogen using steam. To accomplish the periodic regeneration, the EMx™ system is constructed in numerous modules which operate in parallel so that one module can be isolated and regenerated while the remaining modules are lined up for treatment of the exhaust gas stream.

There are currently six EMx™ units in commercial operation with the U.S. All are on natural gas-fired combustion turbines of 45 MW or less.[12] There are no known installations on process heaters or boilers. There are a number of differences between the operation and flue gas characteristics of combustion turbines and CHS's candidate process heaters and boiler considered by this analysis. Specifically, combustion turbines are essentially constant flue gas flow combustion devices no matter what the load. Process heater and boiler gas flow rates are directly proportional to load. The impact on the load following ability of the EMx™ is unknown with respect to process heater and boiler applications. Additionally, the concentration of NOx/NO_2 in the flue gases from the process heaters are much higher than that of the combustion turbine flue gases. This is due to the high oxygen content of the combustion turbine flue gas (~15% O_2) relative to a process heater/boiler flue gas (~3% O_2). The impact of the flue gas oxygen content and NOx/NO_2 concentration on the EMx™ is unknown. Finally, the combustion turbines where EMx™ has been demonstrated have all been fired with natural gas. Of the CHS sources included in this analysis, only Boiler #9 is natural gas fired. Based on the above factors the use of EMx™ to control NOx emissions from the selected CHS process heaters and boiler is considered technically infeasible and this technology is eliminated from further consideration.

3.2.2.3. Ranking of Technically Feasible NOx Control Technologies

Based on the discussion above, the control technologies summarized in Table 3-2 are considered technically feasible for the control of NOx from the selected CHS process heaters and boiler.

Table 3-2. Summary of Feasible NOx Controls for Process Heaters and Boilers

Process Heaters	Boilers
• LNB/ULNB • LNB/ULNB followed by SCR	• FGR • LNB/ULNB • LNB/ULNB followed by SCR

The NOx emission rate achievable as part of a heater or boiler retrofit is dependent upon the inherent design of the heater. Although it may be technically feasible to retrofit an existing heater/boiler with a control, NOx emission rates that are achievable on a new heater/boiler may not be achievable through a retrofit installation. Table 3-3 identifies the NOx emission rates expected to be achievable for the identified process heaters and

[12] The heat input for a 45 MW combined cycle combustion turbine would be approximately 300 MMBtu/hr, assuming an efficiency of 50 percent.

boiler as a result of installation of ULNB (heater) or FGR+ULNB (boiler). The table also notes the NOx reduction expected from the retrofit.

Table 3-3. ULNB Achievable NOx Levels - Process Heaters and Boilers

	Main Crude Heater	Platformer Heater	Boiler #9
Baseline NOx, lb/MMBtu	0.1[a]	0.275[b]	0.098
Post Retrofit NOx, lb/MMBtu	0.05	0.04	0.04
Baseline NOx, tons/year	43.6	91.4	29.3
NOx Reduction, tons/year	21.8	78.1	17.3

[a] LNB technology is currently installed. Burners were guaranteed for 0.08 lb/MMBtu but 0.1 lb/MMBtu has been conservatively used as the basis for emissions calculations. The unit has not been tested to determine the actual NOx rate.

[b] Conservatively assumed NOx emission rate of 0.275 lb/MMBtu based on AP-42. A 2002 stack test indicated actual emission rate of 0.167 lb/MMBtu.

An analysis of recent SCR based precedents for new units where the SCR's placement can be integrated into the heater's design indicated NOx reductions of 85 to 95 percent on an annual average basis. As a result, due to the retrofit related issues of installing an SCR, a design level NOx control of 85% was applied as part of this analysis.

3.2.2.4. Process Heater and Boiler NOx Controls – Costs of Compliance

This subsection documents the cost of compliance associated with retrofitting ULNB and SCR NOx control technologies on the process heaters and boilers identified in Table 3-1. A summary of the estimated costs is presented in Table 3-4. The costs presented were developed in accordance with USEPA's Air Pollution Control Cost Manual methodology.[13] Capital costs were escalated to 2018 dollars using the Chemical Engineering Plant Cost Index. Costs and emission estimates are based on the following:

- NOx rates achievable using ULNB technology are those presented in Table 3-3
- The retrofit installation of SCR following application of ULNB is assumed to achieve 85 percent control of NOx emission
- Emissions reductions were calculated from the actual emissions levels during the period 2017 - 2018 presented in Table 3-1.
- Controlled emissions levels are based on the same equipment utilization level as during the 2017 - 2018 baseline period.

[13] EPA Air Pollution Control Cost Manual Sixth Edition, January 2002; EPA/452/B-02-001.

Table 3-4. Summary of the Cost of Compliance Associated with Application of ULNB and SCR on the Identified Process Heaters and Boilers

PARAMETERS	Main Crude Heater	Platformer Heater	Boiler #9
ULNB			
Total Capital Requirement, $[1]	2,826,000	8,488,000	3,249,000
Annual O&M Costs, $	71,000	212,000	81,000
Capital Recovery Costs, $	267,000	801,000	307,000
Total Annual Costs, $	338,000	1,013,000	388,000
SCR			
Total Capital Requirement, $[1]	6,005,000	6,192,000	5,307,000
Annual O&M Costs, $	263,100	283,400	230,000
Capital Recovery Costs, $	566,900	584,500	501,000
Total Annual Costs, $[1]	830,000	867,900	731,000
NOx Emissions, tons/yr			
Actual Emissions (2017-2018)	43.6	91.4	29.3
Emissions w/ULNB	21.8	13.3	12.0
Emissions w/ULNB + SCR	3.3	2.0	1.8
NOx Reductions			
ULNB	21.8	78.1	17.3
ULNB + SCR	40.3	89.4	27.5
Cost Effectiveness, $/ton			
ULNB	15,500	13,000	22,400
ULNB + SCR	27,800	21,000	39,000

1 – Includes the cost of NOx CEMS

Cost of Compliance

The capital costs associated with the retrofit installation of ULNB and ULNB/SCR range from $2,826,000 to $8,487,000 for ULNB and $5,307,000 to $6,192,000 for SCR on a per unit basis. The capital cost for the UNLB include the ULNB, any modifications needed to accommodate the burner within the heater/boiler, and fuel filter coalescer. The capital cost of the SCR system includes the catalyst; catalyst housing, induced draft fan (if required), ammonia storage system; and ammonia injection system. The annual operating costs range from $338,000 to $1,013,000 for ULNB and $731,000 to $867,000 for ULNB/SCR on a per unit basis. For the ULNB, the annual costs include capital recovery[14] and the annual maintenance cost. For the SCR, the annual operating

[14] Standard USEPA capital recovery factor of 0.11 conservatively based on 20 year control system life and 7 percent cost of money.

costs include capital recovery,[15] catalyst replacement, operating personnel, and maintenance. A catalyst life of three years is assumed. The resulting cost effectiveness range from $13,000 to $22,400 for ULNB and $21,000 to $39,000 for ULNB/SCR per ton of NOx removed.

3.2.2.5. Process Heater and Boiler NOx Controls – Time Necessary for Compliance

The time necessary for compliance is generally defined as the time needed for full implementation of the evaluated control options identified in Table 3-2. This includes the time required to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation, which would need to be coordinated around a planned turnaround to avoid the costs associated with an additional outage. Therefore, compliance deadlines must consider the time necessary for compliance by setting a compliance deadline that provides a reasonable amount of time for the source to implement the control measure.

Table 3-5 presents estimated timeframes needed to implement each of the control technologies. Notably, the estimated timeframes do not account for time needed for the MDEQ to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve the MDEQ regulation into the Montana SIP.

Table 3-5. Heater and Boiler NOx Control System Implementation Schedule

NOx Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)[1]
ULNB	6	6	6	18
ULNB/SCR	6	12	12	30

[1] The total schedule time provided does not account for how a given controls project would be considered within a given emissions unit's turnaround schedule.

3.2.2.6. Process Heater and Boiler NOx Controls – Energy and Non-Air Quality Environmental Impacts of Compliance

Non-Air Quality Environmental Impacts: The application of SCR to the candidate process heaters and boiler will result in the emissions of ammonia and additional fine particulate matter in the form of ammonium salts. The emission of ammonia results from

[15] Standard USEPA capital recovery factor of 0.11 conservatively based on 20 year control system life and 7 percent cost of money.

incomplete utilization of all of the ammonia injected before the SCR catalyst. This unreacted ammonia, referred to as ammonia slip, is either exhausted to the atmosphere as ammonia or combines with sulfur species in the flue gas to form ammonium salts.

The installation of an SCR system increases the pressure drop through the heater flue gas path requiring the installation of an induced draft fan on the Main Crude and Platformer Heaters. The induced draft fan and SCR system power requirements result in an increase in the emission rate of criteria pollutants (NOx, CO, GHGs, etc.) at the location where the power is generated.

The spent catalyst is comprised of metals that are not considered toxic. This allows the catalyst to be handled and disposed of following normal waste procedures.

Energy Impacts: The energy impact of applying SCR to the candidate process heaters and boiler comes from the power required to drive the induced draft fan and operate the ammonia injection and storage equipment.

3.2.2.7. Process Heater and Boiler NOx Controls – Remaining Useful Life

The evaluation of NOx control options should consider the source's "remaining useful life" in determining the costs of compliance. The remaining useful life is the difference between the date that controls would be put in place and the date that the facility permanently ceases operation. If the remaining useful life of the unit is shorter than the useful life of a particular control option, the remaining useful life should be used for annualizing costs. If the remaining useful life exceeds the useful life of the control options, the remaining useful life has no effect on the cost evaluation. CHS has conservatively assumed that the remaining useful life of the facility is expected to be greater than 20 years.

3.2.2.8. Conclusions and Discussion of Other Factors

As shown above, the cost effectiveness of the evaluated NOx controls for the Main Crude Heater, Platformer Heater, and Boiler #9 range from $13,000 to $39,000 per ton of NOx removed. Based on previous determinations that have indicated a control was considered infeasible due to cost at levels well below those presented, it is concluded that additional controls on the candidate heaters and boiler are not cost effective. As such, these three emissions units should not be selected for reasonable controls for Regional Haze on the basis of Cost of Control. Consideration of additional factors is not required.

3.2.3 Refinery Flare

As shown in Table 3-1, the MDEQ requested that CHS complete a four-factor analysis for the control of SO_2 from the Main Refinery Flare. The Main Refinery Flare receives flow from two separate flare headers (*i.e.,* the primary and non-recoverable headers) that are designed to safely accumulate and transfer gases from the refinery processes to the flare for combustion. In addition to hard-piped connections that support normal process operating conditions, the flare gas headers also have connections that support equipment depressurization and purging for maintenance activities, such as startups, shutdowns, and maintenance turnarounds.

The primary flare header delivers vent gas from the process units to either the flare gas recovery system (FGRS) or to the flare stack. Under normal refinery operations, the FGRS is used to direct recovered flare gases to an amine unit for removal of H_2S prior to use in the refinery fuel gas (RFG) system. Although the intent is to maximize the amount of flare gas recovered, certain maintenance activities (e.g. steaming, pressure testing, and nitrogen purging equipment to the flare to ensure safe working conditions) may require bypassing the FGRS to avoid upsetting the RFG system. The FGRS is also bypassed during events when the volume of vent gas that is relieved into the flare header system exceeds the capacity of the FGRS. Such events include emergency releases, process upsets, or unit startups/shutdowns. During an event, the pressure of the gases in the flare header exceeds the back-pressure exerted on the header by a liquid seal and the gases bypass the seal to the flare where they are combusted. The frequency and duration of these activities and events are highly variable and may last for several hours to several days or weeks depending on the specific situation.

The non-recoverable flare header is used to transfer hydrogen-rich gases and excess RFG to the flare. The hydrogen-rich streams are considered non-recoverable due to their low net heating value (*i.e.,* Btu/scf), which has the potential to cause an upset in the RFG system. The sulfur content of the vent gases in the non-recoverable flare header is minimal. As a result, the amount of SO_2 resulting from the combustion of non-recoverable gases is small.

3.2.4 Four-Factor Analysis – Main Refinery Flare SO_2

3.2.4.1. Potentially Applicable Refinery Flare SO_2 Control Technologies

A review of precedents and requirements for flares in the RBLC database, permits, EPA/DOJ consent decrees, and regulations identified flare gas recovery and work practices as potential SO_2 control measures. Work practices identified include the following:

- Flare management plans
- Waste gas minimization plans
- Root cause/corrective action programs
- Flare monitoring requirements

- Proper equipment design
- Proper maintenance practices

3.2.4.2. Technical Feasibility of Available Flare SO_2 Control Technologies

All of the identified control measures are considered to be technically feasible for control of SO_2 from the Main Refinery Flare. The FGRS has been in operation on the Main Refinery Flare since November 2015. It was identified as one element of BACT for the Main Refinery Flare during a 2014 minor modification permit action. In addition, each of the identified work practices are already in place due to the various regulations that are applicable to the Main Refinery Flare, as follows:

- NSPS subpart Ja at § 60.103a(a) and NESHAP subpart CC at § 63.670(o)(1) each require development of a written flare management plan (FMP). The following information is specifically required to be included in or referenced in the FMP:
    - Listing of all process units, ancillary equipment, and fuel gas systems that are connected to the flare header system;
    - A flare minimization assessment;
    - Descriptions of all flare components and design parameters;
    - Specifications for all required monitoring instrumentation;
    - A baseline flow evaluation; and
    - A description of procedures to reduce flaring during planned startups and shutdowns, during imbalances of the fuel gas system, and during outages of a FGRS.

- NSPS subpart Ja requires completion of a root cause/corrective action analysis when the 24-hour total SO_2 from the flare exceeds 500 pounds and/or when the 24-hour total flare flow is greater than 0.5 MMSCF above the baseline.

3.2.4.3. Ranking of Technically Feasible SO_2 Control Technologies

No control measures beyond what are already in place were identified. However, additional SO_2 reductions at the Main Refinery Flare are anticipated as part of ongoing air pollution control programs.

3.2.4.4. Main Refinery Flare SO_2 Controls – Costs of Compliance

No control measures beyond what are already in place were identified in this analysis. The total capital cost of the FGRS installed in 2015 was greater than $50MM.

3.2.4.5. Main Refinery Flare SO_2 Controls – Time Necessary for Compliance

No control measures beyond what are already in place were identified in this analysis.

3.2.4.6. Main Refinery Flare SO_2 Controls – Energy and Non-Air Quality Environmental Impacts of Compliance

No control measures beyond what are already in place were identified in this analysis.

3.2.4.7. Main Refinery Flare SO_2 Controls – Remaining Useful Life

No control measures beyond what are already in place were identified in this analysis. The Main Refinery Flare and FGRS began operation in 2015. It is expected that the flare and FGRS have a remaining useful life greater than 20 years.

3.2.4.8. Conclusions and Discussion of Other Factors

No control measures beyond those already in place at the Main Refinery Flare were identified in the Four-Factor Analysis. As noted in Section 1.0, the MDEQ may consider additional factors beyond those included in the Four-Factor Analysis when determining which controls are necessary to make reasonable progress toward visibility goals. It is anticipated that SO_2 emissions from the Main Refinery Flare will decrease by at least 20% from the 2017 – 2018 baseline by 2028 as a result of ongoing programs and work practices. These programs will continue to identify opportunities to reduce vents to the flare and to increase utilization of the FGRS. Following are two examples of recently identified opportunities:

- Evaluation of flare emissions during maintenance activities identified the potential benefit of additional online analyzers to better identify flare gases that may be compatible with the RFG system. These analyzers have been installed.
- A piping modification is being implemented to allow for recovery and amine treatment of certain flare gases that aren't currently being recovered because they don't meet RFG specifications. Although these recovered gases will be returned to the flare after treatment, SO_2 emissions at the flare will be significantly reduced.

As a result of these ongoing programs, it can be concluded that enforceable emissions limitations, compliance schedules, and other measures are not necessary and that the Main Refinery Flare should not be selected for reasonable control for Regional Haze.