ExxonMobil Fuels & Lubricants Company
700 ExxonMobil Road
P.O. Box 1163
Billings, Montana 59101
406 657 5380 Tel
406 657 5374 Fax

ExxonMobil

CERTIFIED MAIL

Ms. Rhonda Payne
Air Quality Bureau
Permitting Services Section
Department of Environmental Quality
PO Box 200901
Helena, Montana 59620-0901

RE: Regional Haze Four Factor Analysis for ExxonMobil Billings Refinery

Dear Ms. Payne:

Enclosed is the Regional Haze Four Factor Analysis report for the ExxonMobil Billing Refinery that the Department requested on April 19, 2019. Please call me at (406) 545-1155 if you have any questions or comments on the report.

Sincerely,

Joe Lierow

Joe Lierow, PE
Environmental Section Supervisor

Signature Date: 11-15-19

Enclosure

cc: Ms. Debbie Skibicki, Bison Engineering, Inc.

BISON
ENGINEERING, INC.

Regional Haze
Four-Factor Analysis

ExxonMobil

Billings Refinery

700 ExxonMobil Road
Billings, Montana

November 2019

Prepared by:
Bison Engineering, Inc.
1400 11th Avenue, Ste. 200
Helena, MT 59601

EXECUTIVE SUMMARY

Bison Engineering, Inc. (Bison) was retained by the Exxon Mobil Corporation– Billings Refinery (Billings Refinery) to prepare a four-factor analysis for its petroleum refinery sited in Billings, MT. The four-factor analysis was requested by the Montana Department of Environmental Quality (MDEQ) in an email (and follow up discussions) between Joe Lierow (Billings Refinery) and Craig Henrikson (MDEQ) on March 14, 2019.

The analysis itself relates to the second planning period (Round 2) for development of a State Implementation Plan (SIP) to address Regional Haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308. The purpose of the four-factor analysis is to determine if there are cost effective emission control options at the Billings Refinery that, if implemented, could be used to attain reasonable progress toward the state's visibility goals.

The four-factor analysis focused on oxides of nitrogen (NO_x) for three primary emissions units/sources: the Coker CO Boiler (KCOB), the F-1 Crude Furnace/F-401 Vacuum Heater listed under EU01 – Crude Unit in operating permit #OP1564-17, (F-1/F-401), and the F-551 Heater (F-551). The KCOB, F-1/F-401, and F-551 are responsible for approximately 52% of the NO_x emissions from the refinery based on the 2015-2016 emissions baseline. To represent cost and control impacts on the smaller refinery process heaters, F-201 Hydrofiner Heater was analyzed with respect to the four-factor analysis. Furthermore, facility-wide emissions reduction efforts have been described in this analysis. The results of the analysis have indicated that additional controls on KCOB, F-1/F-401, F-551, and F-201 (representative of similar smaller process heaters) are not necessary to make reasonable progress due to costs and the Billings Refinery's lack of measurable impact on any nearby Class I area. In addition, significant emission reductions have occurred in the Billings area, including the shutdown of a facility averaging 2,744 tons of sulfur dioxide (SO_2) and 1,739 tons of NO_x over the 2000-2014 annual emission inventory years.

TABLE OF CONTENTS

LIST OF TABLES AND FIGURES

LIST OF APPENDICES

1.0 ACRONYMS

Anthro Dv	Anthropogenic deciview impairment
ARM	Administrative Rules of Montana
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Billings Refinery	Exxon Mobil Corporation – Billings Refinery
Bison	Bison Engineering, Inc.
CAA	Clean Air Act
CHUB	Catalytic Hydrotreating Unit
CO	Carbon Monoxide
Control Cost Manual	EPA Air Pollution Control Cost Manual
DeSOx	Desulfurization
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
F-1/F-401	F-1 Crude Furnace/F-401 Vacuum Heater
F-201	F-201 Hydrofiner Heater
F-551	F-551 Heater
FCCU	Fluidized Catalytic Cracking Unit
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
FIP	Federal Implementation Plan
H_2S	Hydrogen Sulfide
ID Fan	Induced Draught Fan
IMPROVE	Interagency Monitoring of Protected Visual Environments
KCOB	Coker Carbon Monoxide Boiler
lb/MMBtu	Pounds per Million British Thermal Units
MDEQ	Montana Department of Environmental Quality
MSCC	Montana Sulphur and Chemical Company
NAAQS	National Ambient Air Quality Standards
NACAA	National Association of Clean Air Agencies
NH_3	Ammonia
NO_x	Oxides of Nitrogen
O_2	Oxygen
O&M	Operations and Maintenance
ppm_v	parts per million by volume
r	Pearson Correlation Coefficient
r^2	the square of the correlation coefficient r
RFG	Refinery Fuel Gas
RHR	Regional Haze Rule
Round 1	First planning period of the Regional Haze Program
Round 2	Second (current) planning period of the Regional Haze Program
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
TSD	Technical Support Document
ULNB	Ultra-Low NO_x Burners
WRAP	Western Regional Air Partnership
YELP	Yellowstone Energy Limited Partnership

2.0 INTRODUCTION

As part of the 1977 amendments to the Federal Clean Air Act (42 USC 7401 et. seq.) Congress declared as a national goal "… the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution" (42 USC 7491(a)(1)). With that goal, plans and requirements were eventually codified in the Code of Federal Regulations primarily in 40 CFR 51.308 (the entire visibility program is found in 40 CFR 51.300 to 309). These regulations require individual states to establish "reasonable progress goals" in order to "attain natural visibility conditions" by the year 2064 (40 CFR 51.308(d)(1)).

The Environmental Protection Agency (EPA), via a Federal Implementation Plan (FIP) promulgated the first round of those obligations with the establishment of Best Available Retrofit Technologies (BART) and a four-factor analysis for various sources in Montana.[1] The ExxonMobil Billings Refinery (and the CHS Laurel Refinery) were determined to be BART-eligible facilities, but the subsequent BART analysis did not justify add-on controls [1]. In addition, the other Montana refineries were not considered for analysis at the time presumably due to their recent investment in and installation of pollution control technologies as a result of the EPA Refinery Consent Decree process, which also affected the ExxonMobil Billings Refinery and the CHS Laurel Refinery. Therefore, the FIP did not propose nor promulgate any additional controls for these facilities.

A second round of obligations is now under development, with MDEQ as the lead agency. This second round, or planning period as it is sometimes referred, requires the evaluation of additional steps toward reasonable progress in meeting the national goal of attaining natural visibility conditions in mandatory Class I areas by 2064. The Regional Haze Rule (RHR) as outlined in 40 CFR 51.308 *et seq*. identifies four factors which should be considered in evaluating potential emission control measures to make reasonable progress toward the visibility goal. The evaluation of these four factors for regional haze emission control measures is known as the four-factor analysis. The four factors are as follows:

Factor 1. Cost of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance
Factor 4. Remaining useful life of any existing source subject to such requirements

In March of 2019, MDEQ contacted the Billings Refinery and requested that it conduct a four-factor analysis. MDEQ noted this same analysis is required for other major sources of SO_2 and NO_x emissions in the Billings area as well. MDEQ followed up with an April 19, 2019 letter to further clarify various aspects of the requested analysis along with providing EPA guidelines on the matter. In a May 23, 2019 email, MDEQ requested a "representative

[1] The FIP was promulgated on Sept. 18, 2012 at 77 FR 57864.

baseline" emissions period on which to base regional modeling as a part of the Round 2 efforts. The Billings Refinery chose the 2015-2016 annual emission years as the operationally representative baseline within the 2014-2017 timeframe suggested by MDEQ.[2] Those 2015-2016 annual emissions years are also used as a basis for this four-factor analysis.

2.1 Facility Information

The Billings Refinery is designed to process a variety of crude slates including those containing high sulfur crude oil. Major process units include: atmospheric and vacuum crude distillation towers, a fluidized catalytic cracking unit (FCCU), a hydrocracker and hydrogen plant, a fluid coker, a naphtha fractionator, a catalytic reformer, an alkylation unit, three hydrotreaters for polishing the naphtha and distillate streams, and a catalytic hydrotreating unit (CHUB). The Billings Refinery does not have a sulfur recovery unit within the refinery. Refinery gases high in hydrogen sulfide (H_2S) are piped to an off-site sulfur recovery plant owned and operated by the Montana Sulphur and Chemical Company (MSCC). MSCC extracts sulfur from the sour refinery fuel gas (RFG) and returns sweetened fuel gas to the Billings Refinery. The Billings Refinery sends coker process gases to the Yellowstone Energy Limited Partnership (YELP) facility for treatment (combustion) in two boilers, except when YELP is not operating. The MSCC and YELP facilities are considered by the Federal Clean Air Act (CAA) and the Administrative Rules of Montana (ARM) as facilities that are separate from the ExxonMobil Billings Refinery. The Billings Refinery and the adjacent bulk terminal are considered one facility for the purpose of any permitting completed in accordance with the New Source Review program and Title V program. The bulk terminal does not produce SO_2 or NO_x emissions and is not considered in this analysis.

The Billings Refinery encompasses approximately 760 acres, and the location of the main refinery gate is 700 ExxonMobil Road, Billings, Montana. The legal description of the site location is S½ of Section 24 and N½ of Section 25, Township 1 North, Range 26 East, in Yellowstone County, Montana. The site elevation is 3,085 feet above mean sea level.

A USGS topographic map is included as *Figure 1* showing the site location. *Figure 1* also shows the boundary of North Absaroka Wilderness Area, which is the nearest Class I area to the Billings Refinery, approximately 144 kilometers to the southwest. *Figure 2* is a printout of a Google Earth satellite photo of the area surrounding the facility, with the site location indicated.

[2] See email letter from MDEQ dated July 9, 2019

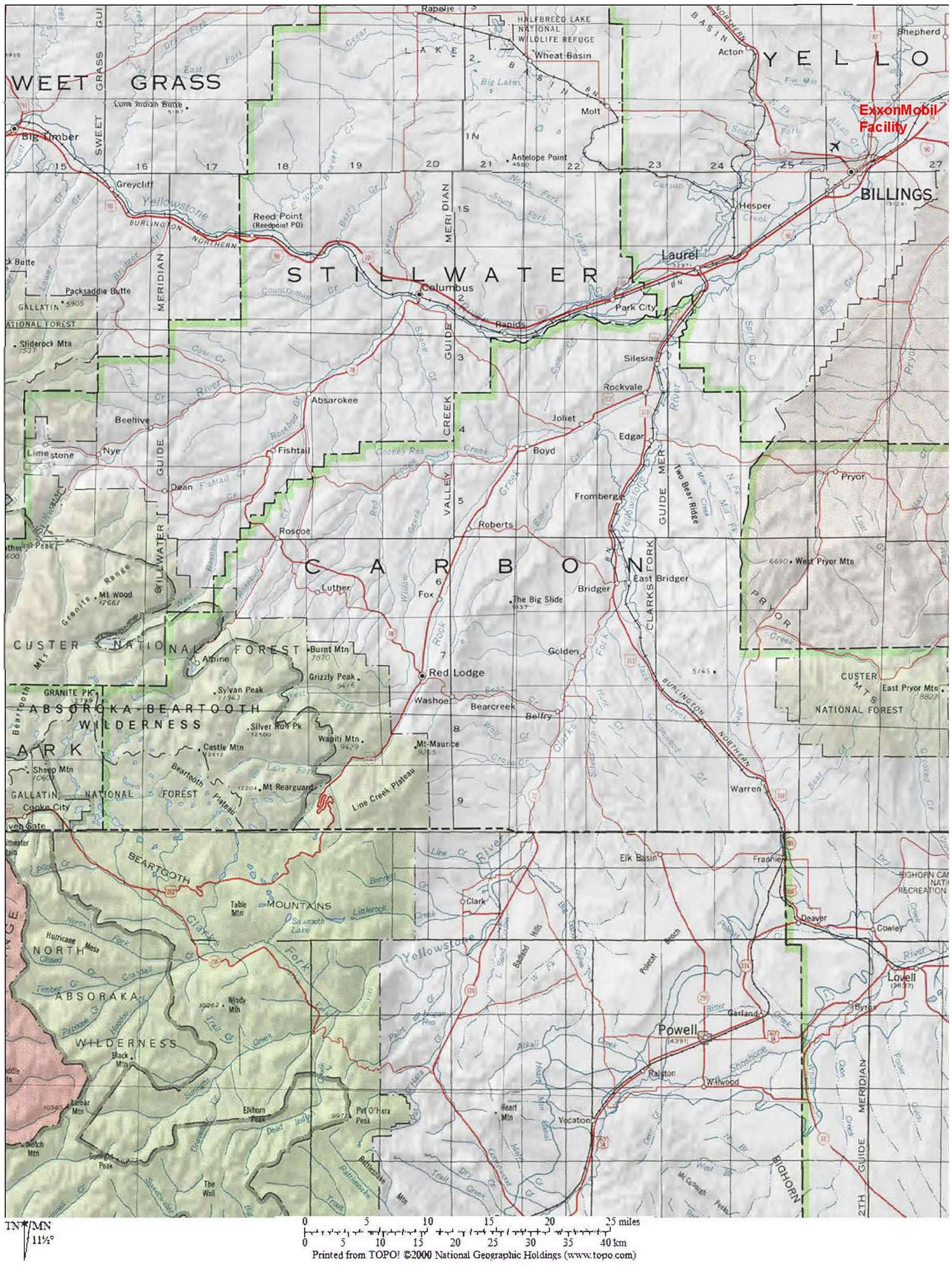

Figure 1: Topographic Map of the Billings Refinery in relation to nearest Class I area

Figure 2: Google Earth representation of the Billings Refinery

3.0 PROGRAM SUMMARY and STATUS

As previously stated, the Regional Haze program's goal is to attain 'natural' (nonanthropogenic) visibility conditions in all mandatory Class I areas[3] by 2064. The RHR itself was promulgated in substantially its current form in 1999. Adjustments/updates to the 1999 rule were made in 2017.[4] The rule has been implemented in incremental steps. The first step, or sometimes referred to as the 1st planning period (Round 1), was a combination of BART and a four-factor analysis. During this initial planning period BART applied to certain older facilities and[5] the four-factor program, applied to 'larger' facilities who had a potential of impacting (visibility) in a mandatory Class I area. As previously mentioned, the Billings Refinery was determined to be a BART-eligible facility, and the BART analysis did not result in add-on controls being applied [1].

3.1 Montana Initiatives

For Montana, the Round 1 requirements were executed by the EPA. This planning period roughly included the period of 2006 to 2018. In July 2006, Montana determined that it had insufficient resources to manage the program and thus returned the program to EPA.[6] Following much discussion and analyses, EPA (six years later) promulgated a FIP as it applied to sources in Montana.[7] As previously discussed, the Billings Refinery was not included in the FIP, therefore, no additional or new controls were required for the Billings Refinery for the Round 1 planning period.

Given the timeframe for Round 1 has expired, the RHR now requires the implementation of Round 2. Round 2 is meant to show an incremental progress toward the national goal for the 10-year period 2018 to 2028. Additional 10-year implementation periods will follow until the national goal is achieved (40 CFR 51.308(f)).

Recently, MDEQ elected to resume management of the regional haze program. With that decision, MDEQ is taking the lead in the development of the four-factor analysis and plans associated with the second planning period. Currently, MDEQ is planning, by July 2021, to submit a SIP to EPA with the enforceable reductions (emission limits or plans that will go into effect prior to 2028).

To implement the program fully, it was first necessary to measure regional haze (visibility and its constituents) in the various Class I areas. This has been an ongoing effort via various ambient monitoring programs. Among them is the Interagency Monitoring of Protected Visual Environments (IMPROVE) program [2]. This visibility monitoring program

[3] A mandatory Class I area is usually a national park or wilderness area above a certain threshold size (4,000 or 5,000 acres) and in existence on or before August 7, 1977. Montana has 12 (of 156) such areas.
[4] 64 FR 35765; July 1, 1999; and 82 FR 3124; Jan. 10, 2017.
[5] The BART program is more fully explained in 40 CFR 51.308(e).
[6] Letter from MDEQ to EPA dated July 19, 2006.
[7] The proposed FIP was published April 20, 2012 at 77 FR 23988 and became final on Sept. 18, 2012 at 77 FR 57864.

began in 1988 and continues to be a cooperative effort between EPA and various federal land managers (primarily the National Park Service and the US Forest Service). The results of that monitoring have indicated, for eastern Montana and Wyoming Class I areas, the primary pollutant(s) that account for the most anthropogenic (human-caused) regional haze degradation are (ammonium) sulfate and (ammonium) nitrate [3,4].

For Round 2, MDEQ has elected to look for additional reductions in SO_2 and NO_x (precursors to ammonium sulfate and ammonium nitrate) emissions. The sources selected for the analysis are those facilities whose emissions-to-distance (from the Class I area) ratio exceeds a particular value as noted below:

If Q/d > 4, then the facility is chosen for a four-factor analysis
Q = mean annual emissions from 2014 to 2017 of $SO_2 + NO_x$ (tons)
d = distance to the nearest mandatory Class I area (kilometers)

A value greater than 4 was calculated for the Billings Refinery for the given time period (7.20 specifically, based on the 2014-2017 annual emission inventory period) and thus was chosen by MDEQ for a four-factor analysis in Round 2.

3.2 Federal Initiatives

It is important to understand the purpose of the RHR visibility protection program in order to select criteria that will lead to the most reasonable progress requirements.

A visibility program aimed at attaining national visibility goals in mandatory Class I areas was authorized in Section 169A of the Clean Air Act (42 USC 7491). The national goals are to be attained by the year 2064, approximately 45 years from now. The rules which are to implement this goal of protecting visibility are found at 40 CFR 51, Subpart P (subsections 300 through 309). A review of Subpart P indicates the purpose and goals of the program. The purposes of the program are outlined as follows:

> "*The primary purposes of this subpart are . . .to assure* ***reasonable progress*** *toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment* ***results*** *from manmade air pollution. . ."* [40 CFR 51.300(a) (emphasis added)].

The visibility program may be thought of as the implementation of two sub-programs. One regards new source review (NSR, PSD, etc.) and the other addresses "regional haze." Regional haze may further be broken down into the BART program and the reasonable progress program. The underlying reason stated for MDEQ's March 13, 2019 letter and other correspondence to the Billings Refinery relates to reasonable progress achieved through the four-factor analysis.

In that regard, the RHR outlines what it refers to as: "the core requirements" for the implementation of the regional haze goals. More specifically, 40 CFR 51.308(d)(1) states:

> "*For each mandatory Class I Federal area . . ., the State must establish goals . . . that provide for reasonable progress towards achieving natural visibility conditions.* ***The reasonable progress goals must provide for an improvement in visibility*** *for the most impaired days...*"

The rules go on to provide the states with a list of what must be considered in developing reasonable progress. Among these details are the four-factor analysis that is outlined above in *Section 2.0* and in the March 13, 2019 letter.

3.3 Overall Applicability

Montana is tasked to establish (a plan for) reasonable progress in carrying out the visibility protection. *Section 3.1* outlines the purpose of the program along with core elements. To that end, MDEQ requested a "*detailed review of additional process controls*" which is assumed will be evaluated by both Montana and EPA for applicability in establishing a set of specific, reasonable Montana control strategies that create "Reasonable Progress" toward the 2064 goals.

The purpose of the program is to protect visibility by remedying, reducing, and preventing man-made impairments (or activities) over time in mandatory Class I areas. Reasonable progress expresses the notion that states must have implementation plans to approach the national goal by 2064 along a 'glide-path' of improvements to visibility, with certain exceptions. Based on the language contained in 40 CFR 51.308(d)(1), it can be ascertained that any activity, remedy or control (proposed or otherwise) that does not reasonably "improve visibility" in a mandatory Class I area is not a rational candidate for those "reasonable progress" goals [5]. That sentiment is confirmed in Section II.A EPA August 20, 2019 guidance [6]:

> *"The CAA and the Regional Haze Rule provide a process for states to follow to determine what is necessary to make reasonable progress in Class I areas. As a general matter, this process involves a state evaluating what emission control measures for its own sources, groups of sources, and/or source sectors are necessary in light of the four statutory factors, five additional considerations specified in the Regional Haze Rule, and possibly other considerations (e.g., visibility benefits of potential control measures, etc.). States have discretion to balance these factors and considerations in determining what control measures are necessary to make reasonable progress."*

As a result, an analysis that only considers one or more emission control options is not rigorous enough for inclusion into reasonable progress mandates unless those emission controls are expected to improve actual visibility in a Class I area in a discernible manner. It is neither necessary nor appropriate to include an emission control as part of a reasonable progress goal or plan without a reasonable expectation of a resulting improvement in regional haze as a direct result of the application of the control (i.e., a discernible improvement in deciviews[8] in a Class I area).

To that end, the Billings Refinery has elected to not only analyze various control “options” utilizing four-factors, but has also included a qualitative analysis of impacts the Billings Refinery may have on several nearby mandatory Class I areas.[9] This was accomplished to determine if either the current configuration or future control options would fulfill the underlying need of the program to “***provide for an improvement in visibility***” per 40 CFR 51.308(d)(1) at a mandatory Class I area [7].

As will be presented in following sections of this document, no measured evidence of impact by the Billings Refinery’s operations on the visibility in any mandatory Class I airshed was established.

[8] The definition of a deciview is as follows: Deciview haze index=10 $\ln_e(b_{ext}/10\ Mm^{-1})$. This is taken from the definitions found in 40 CFR 51.301. There are, of course, numerous articles and explanations for the deciview metric. One article may be found in the publication “IMPROVE,” Volume 2, No. 1, April 1993 which was written by Pitchford and Malm, 1993. From a non-mathematical point of view, the change in deciview of “1” is intended to represent a “just noticeable change” (or sometimes referred to as ‘just discernible’) in visibility regardless of the baseline visibility.

[9] The nearest Class I area (North Absaroka Wilderness Area) is about 140 kilometers from Billings, Montana.

4.0 REASONABLE PROGRESS PERSPECTIVE

The first few sections of this report have provided a summary of the overall regional haze program and the nature of Round 2 of implementation. It also outlined the program's basic elements and background. This section of the report describes the efforts already taken to reduce emissions not only from the state, but in the Billings-area in particular. This review and discussion lead one to conclude that enough reductions have or are about to be achieved which, by themselves constitutes (more than) reasonable progress within the meaning of the RHR [1].

4.1 National Emissions

A national downward trend of industrial emissions of SO_2 and NO_x has been evidenced for many years. *Figure 3* depicts the nation-wide emission rate of these two compounds from 1990 through 2017.

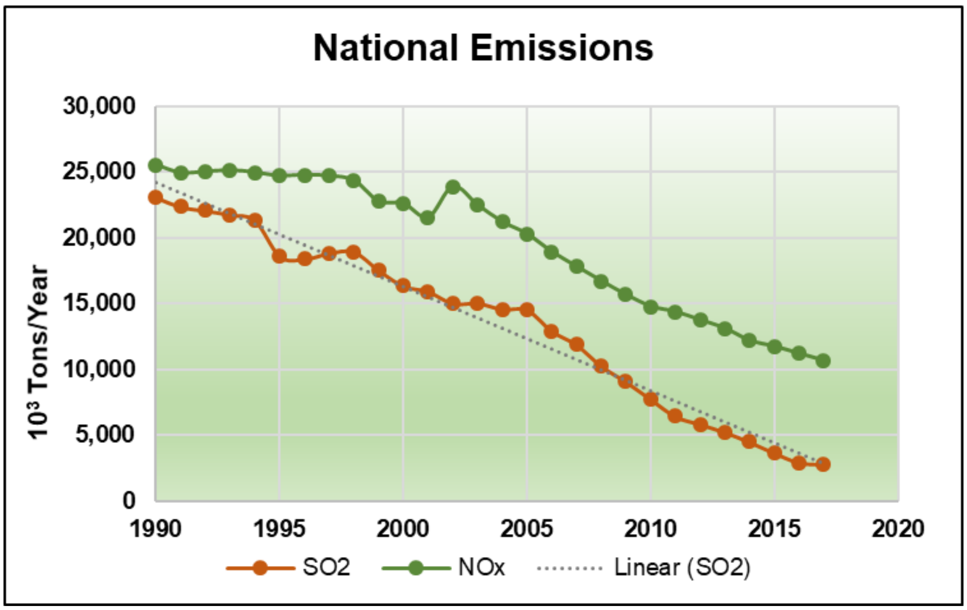

Figure 3: National Emission trends of SO_2 and NO_x

The reductions observed over these years have occurred for many reasons mostly relating to requirements in the Federal Clean Air Act, the Montana Clean Air Act and industrial facility shutdowns.

While *Figure 3* provides a historical perspective, it is also of interest to explore those emissions recorded at the start of the RHR program (2000) as shown in *Figure 4*. This graphic denotes SO_2 emissions through 2064 since that is the year in which the national goal is to be achieved.

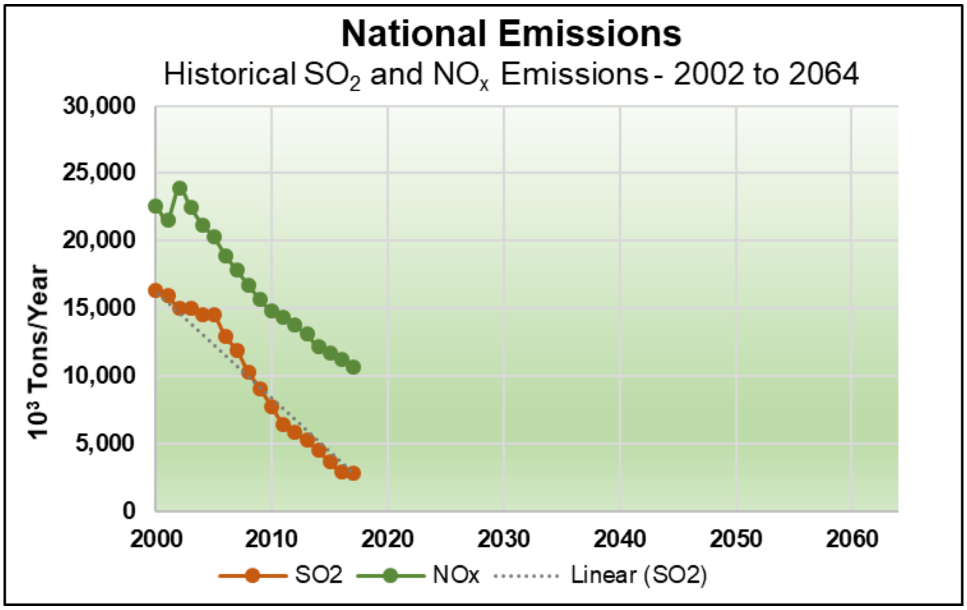

Figure 4: Historical SO_2 and NO_x Emissions

From a national perspective, it appears that emissions of SO_2 and NO_x are on a fast-downward trend. While emissions will not likely achieve "zero" by 2064, substantial reductions have and will likely continue to occur. Regardless of the decisions to be reached for Round 2, national emissions contributing to regional haze are anticipated to decline with or without any observed visibility impairment.

4.2 Montana Emissions

As depicted in *Figure 5*, the Montana trend of lower industrial emissions follows the same general pattern as the national data. Except for a modest spike in NO_x emissions around year 2000, there has been a marked reduction in both NO_x and SO_2. It can be inferred: Montana has been doing its part to reach the national goal.[10]

[10] This statement presumes (without admission or proof) an *a priori* cause and effect between Montana emissions and observed visibility in any nearby Mandatory Class I area. For reasons that will be forthcoming in this four-factor analysis, there is, in our opinion, no clear cause and effect relationship between the Billings Refinery NO_x and SO_2 emissions in particular and a measurable impact on visibility (expressed in deciviews).

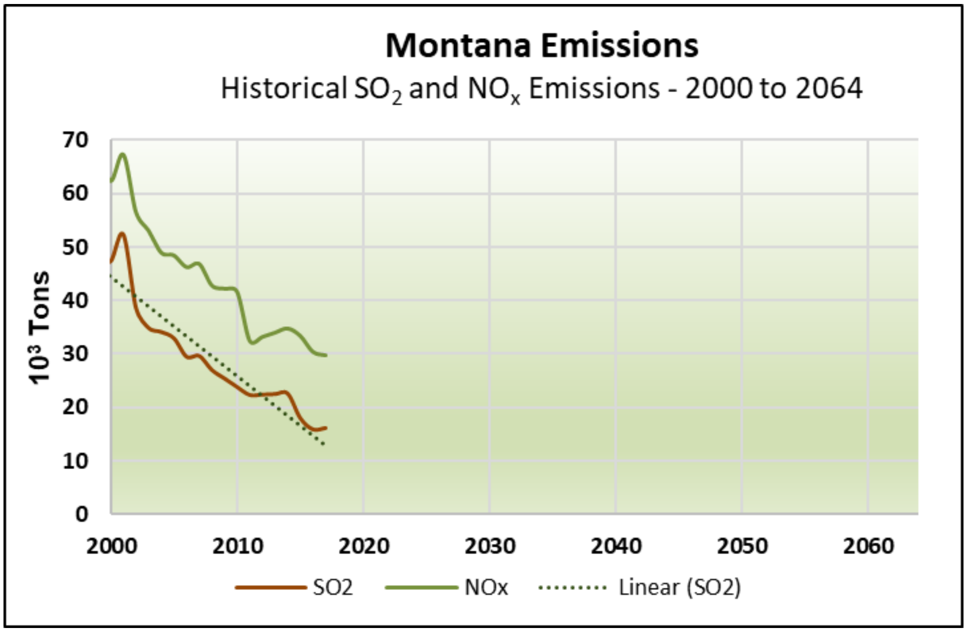

Figure 5: Montana Industrial SO_2 and NO_x emissions

Regardless of the decisions to be reached for Round 2, industrial emissions within the State of Montana contributing to regional haze are anticipated to decline with or without any observed visibility impairment.[11]

4.3 Billings Area Emissions

Regionally, the Billings area emissions follow a very similar trend as seen in Montana above. The major Billings area industrial sources include the ExxonMobil Billings Refinery, the CHS Laurel Refinery, the Phillips 66 Billings Refinery, MSCC, Western Sugar, and YELP. Until its closure in 2015, the Billings area industrial sources also included the J.E. Corette Power Plant, which was one of the largest sources of SO_2 and NO_x emissions in that area averaging 2,774 tons/year of SO_2 and 1,739 tons/year of NO_x between the 2000-2014 annual emission inventory years. Those emissions are no longer in the airshed. Overall, the Billings area has seen a reduction in SO_2 emissions from 25,500 tons/year in 1994 to 4,000 tons/year in 2018, a decrease of roughly 85%. Similarly, NO_x emissions have also decreased from 6,416 tons/year in 2000 to 2,130 tons/year in 2018, a decrease of roughly 67%.

Similar to the national and Montana perspective, *Figure* 6 depicts the RHR program through its anticipated ending in 2064 for the major Billings area industrial sources.

[11] It is assumed for this discussion alone that a reduction in emissions (SO_2 and/or NO_x) has a direct causal relationship with improved visibility. Analyses to follow will show that this is not necessarily the case. A reduction in Montana emissions, the Billings Refinery included, does not translate to an improvement in Class I visibility; linear or otherwise.

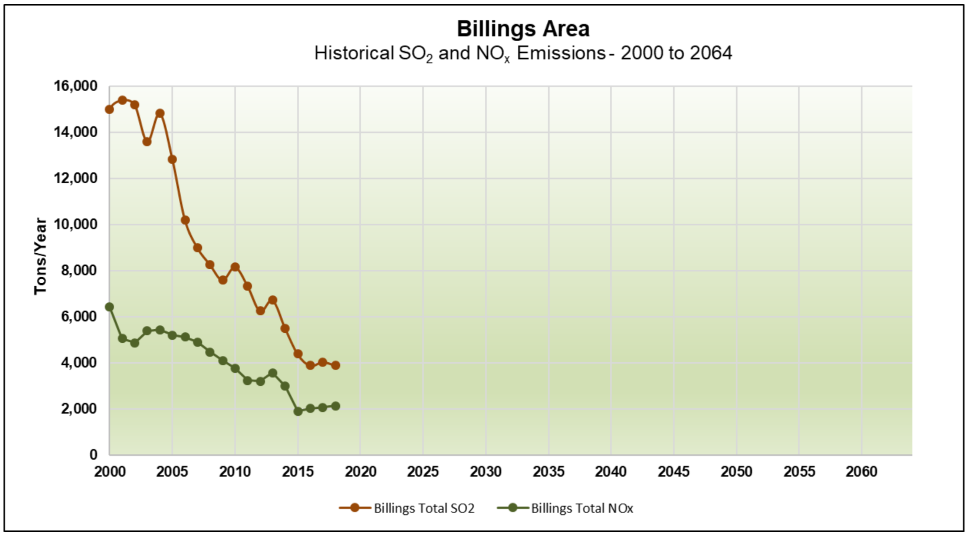

Figure 6: Billings Area SO_2 and NO_x Emissions from 2000 to 2064

This graphic indicates there has been a dramatic reduction in emissions since the inception of the RHR program. On its face, this demonstrates that there has been more than reasonable progress toward the national goal (assuming emissions were to have a direct effect on improvement in visibility).

4.4 Billings Refinery Emissions and Perspectives

As this request for information arises from the RHR, it is important to understand the nature and purpose of the visibility protection program to ascertain important criteria that will lead to the selection of specific reasonable progress requirements.

The RHR program (under MDEQ or EPA) has not previously considered the Billings Refinery's emissions as appropriate candidates for additional control under the reasonable progress (or any other) criteria. First, the Billings Refinery's emissions (historical and current actuals) have been addressed and controlled by separate implementation plans, voluntary emission limitations, the federal refinery consent decree, several new and revised NSPS/MACT regulations, and by subsequent federal implementation plan actions between 1998 and 2008.

Second, Montana and more particularly Billings-area emission inventory data (shown above) clearly shows substantial and adequate reductions in SO_2 and NO_x emissions in the period since 2000 (and earlier although not shown in the figures as a matter of convenience). These reductions have resulted from voluntary source actions, implementation plans, plant closures, new and revised refinery specific regulations, new plant constructions, and numerous consent decrees. Annual SO_2 emissions in Billings have fallen over 84% since 1994; 74% since 2002 (approx. start of RHR program). More notably, a 53% reduction in SO_2 emissions has been realized for the first planning period (2008 to 2018). Similarly, annual NO_x emissions have decreased 56% from 2002 and 52% during the first planning period. These statistics are clear evidence that emission reductions from the Billings area are well ahead of any desired "uniform rate" of visibility improvement or progress contemplated to date at any nearby Class I area [1].[12] The "uniform rate of progress" line is also referred to as the glidepath, which is the linear representation of the visibility improvement needed to get from the baseline at a Class I area to its "natural background" in 2064.

To be consistent with previous historical (and projected) emission summaries, the same information is provided graphically below for the RHR program history.

[12] These uniform rates of progress for Montana's Class I areas are taken in general terms from those "glidepaths" shown in "State of Montana Regional Haze, 5-Year Progress Report," MDEQ, August 2017, Appendix C, Figures 9, 31, 42, 64, 53, 75, 86, 97 and 108.

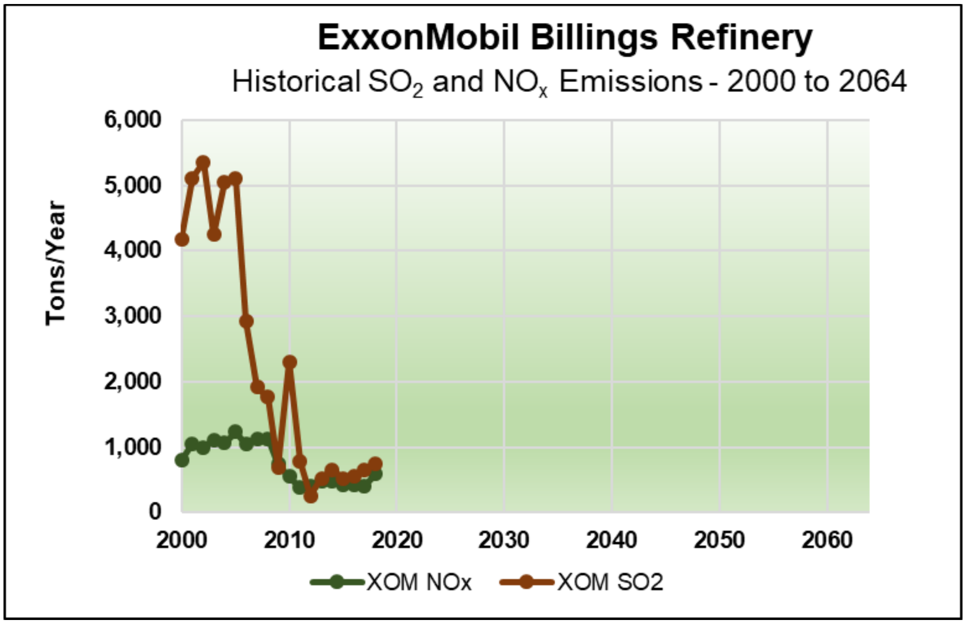

Figure 7: The Billings Refinery SO_2 and NO_x Emissions from 2000 to 2064

Consistent with previously shown data, the rate of reduction of emissions represents a rate that is beyond "reasonable progress" in attaining the national goal, particularly with respect to SO_2.

4.5 Emissions vs Visibility Impairment Analysis

The next step in the reasonable progress perspective is to analyze the current and historical visibility measurements against emissions. A review of anthropogenic sources, and to what extent, these sources might actually impact the Class I area of interest was completed to determine the anthropogenic impact on visibility. There are several methods one may employ to determine if any emission reduction would lead to an improvement in visibility at a 'nearby' Class I areas. This analysis reviews the information in retrospect, and also discusses how that data informs predictions of future visibility impacts.

In order to consider the results of a four-factor analysis as described by the RHR, there must be first and foremost a reasonable probability of an actual improvement in visibility impairment from the Billings Refinery itself or combined with other nearby sources.

In addition to emissions data, there are concurrent visibility data at all the 'nearby' Class I areas. Visibility data from these areas was taken from the Western Regional Air

Partnership (WRAP) [8] and generated from IMPROVE[1,2,9]. These areas and their closest proximity to the Billings Refinery are shown below.

Table 1: Nearby Class I Areas and Proximity

Nearby Class I Area	Approximate Distance from the Billings Refinery (*kilometers*)
North Absaroka Wilderness Area	144
Yellowstone National Park	146
UL Bend Wildlife Refuge Area	190
Gates of the Mountains Wilderness Area	270
Theodore Roosevelt National Park	405

Emissions data from the Billings Refinery spans both the baseline period for the visibility program (2000 to 2004) as well as Round 1 (2005 to 2018). As stated previously, Round 1 encompassed the analysis and implementation of BART along with a four-factor analysis that took place concurrently. EPA included the Billings Refinery in early consideration pursuant to the BART program, but no requirements were promulgated.

It is, therefore, possible to glean some insight as to whether the visibility data is responding to changes in emissions during the same time period. If the Billings Refinery had a measurable impact on visual impairment at a Class I area, then the observed visibility (using deciviews as the indicator) would follow the trend. Due to a myriad of statistical confounding variables, meteorology among them, it would not be expected that this correlation between emissions and visibility (deciviews) to be necessarily linear or strong. Nonetheless, if the Billings Refinery has a significant increase or decrease in emissions during the monitoring period (2000 to present), it is logical to assume that the deciview parameter followed this trend.

The sections below provide such a comparison between emissions and various nearby Class I areas, first graphically, then with respect to statistical correlation.

4.5.1 North Absaroka Visibility vs Emissions

The first Class I area for consideration is the North Absaroka Wilderness area because it is the closest to the Billings Refinery. The wilderness area is located roughly 144 kilometers south west from the Billings Refinery. As with the analyses that follow, the visibility/glidepath data used in this analysis were taken from the WRAP Technical Support System [1,2].

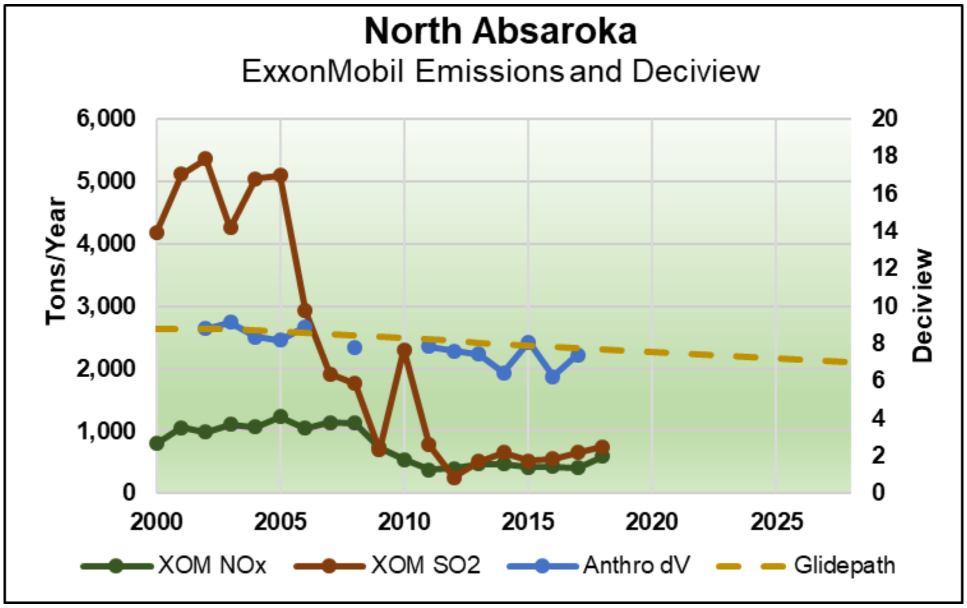

Figure 8: The Billings Refinery SO_2 and NO_x Emissions from 2000 to 2018 compared with the North Absaroka Wilderness Area visibility glidepath through 2028

The analysis starts by a graphical review of the emissions and visibility data over time. The figure compares visibility (Anthro dV refers to anthropogenic deciview impairment) and the RHR glidepath at North Absaroka Wilderness Area with the Billings Refinery SO_2 and NO_x data. The glidepath refers to the line of projected improvements from the starting point of the RHR in 2000-2004 to “natural background” in 2064. Each Class I area has its own glidepath, specific to its visibility degradation baseline.

The most important observation to be gleaned from this chart is that the observed deciview data indicates that this Class I area is already exceeding the uniform rate or progress requirement on its glidepath. If there is no change in emissions from all SO_2 and NO_x sources (Billings and otherwise) and all other parameters remain the same, the North Absaroka area will have achieved the glidepath at the end of 2028 without any reductions required during Round 2.

Visibility and NOx Correlation Calculations							
North Absaroka Wilderness Area							
		Anthro dV	*All dV*	*Billings NOx*	*Glidepath*	*Anthro NO_3*	*XOM NOx*
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Billings NOx	0.74	-0.12	1			
	Glidepath	0.80	-0.11	0.96	1		
	Anthro NO_3	0.53	-0.40	0.78	0.76	1	
	XOM NOx	0.68	-0.10	0.82	0.83	0.65	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.07	1				
	Billings NOx	0.54	0.02	1			
	Glidepath	0.64	0.01	0.92	1		
	Anthro NO_3	0.28	0.16	0.60	0.57	1	
	XOM NOx	0.46	0.01	0.66	0.69	0.42	1

Figure 9: Correlation Analysis for the Billings Refinery NO_x and Visibility Indicators at North Absaroka Wilderness Area

Visibility and SO_2 Correlation Calculations							
North Absaroka Wilderness Area							
		Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*XOM SO_2*
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Billings SO_2	0.77	-0.16	1			
	Glidepath	0.80	-0.11	0.95	1		
	Anthro SO_4	0.62	-0.25	0.74	0.83	1	
	XOM SO_2	0.71	-0.19	0.95	0.87	0.62	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.07	1				
	Billings SO_2	0.59	0.03	1			
	Glidepath	0.64	0.01	0.90	1		
	Anthro SO_4	0.39	0.06	0.55	0.69	1	
	XOM SO_2	0.51	0.04	0.91	0.76	0.38	1

Figure 10: Correlation Analysis for the Billings Refinery SO_2 and Visibility Indicators at North Absaroka Wilderness Area

To complete the evaluation a correlation analysis is also presented in *Figures 9 and 10*. Specifically, the Pearson Correlation Coefficient (r) was determined. The correlation coefficient measures the linear correlation between two variables as shown in *Appendix A*, for example comparing the Billings Refinery SO_2 emissions with the glidepath (multiple variables are compared). The value of “r” may vary from -1 to +1. A value of -1 indicates a negative correlation (when one variable increases, the other variable decreases). A value of zero indicates no correlation whatsoever and a value of +1 indicates a positive correlation.

The other variable of interest is r^2 (the square of the correlation coefficient r). This variable is useful because it gives an indication of the strength of a correlation. In general, the r^2 value is an indication of what percentage of the data fits the linear model of a correlation between the two variables. For example, an r^2 value of 0.50 would indicate that roughly 50% of the data fits the linear model well. Or put another way, 50% of the data suggests a good linear correlation and 50% of the data suggests no correlation.

In this instance, the Billings Refinery NO_x emissions could share a slight trending relationship to Anthro dV (overall human caused visibility impairment)[13] and Anthro NO_3 (the portion of anthropogenic visibility impairment tied to NO_3 compounds) with r values of 0.68 and 0.65, respectively. Similarly, with respect to SO_2, a slight trending relationship was seen between Anthro dV, Anthro SO_4 (the portion of anthropogenic visibility impairment tied to SO_4 compounds) and the Billings Refinery SO_2 emissions (at r values of 0.71 and 0.62, respectively). These trending relationship makes sense because all of the indicators were trending down.

The strength of the trending correlation is indicated by the r^2 variable. The highest r^2 calculated for all of the variables described above is 0.51 between the Billings Refinery SO_2 emissions and Anthro dV, indicating 51% of the data suggests good linear correlation, but 49% suggests no correlation. Correlation does not necessarily imply causation and low r^2 values generally indicate insufficient correlations/relationships in the data.

4.5.2 Yellowstone National Park Visibility vs Emissions

Yellowstone National Park is the next Class I area considered. This national park is located roughly 146 kilometers southwest of the Billings Refinery. Figure 11 compares visibility (Anthro dV) and the RHR glidepath at Yellowstone National Park with the Billings Refinery SO_2 and NO_x data. In reviewing the figure below, the observed visibility at Yellowstone National Park seems, on the whole, to be following the designed glidepath.[14] As indicated in the previous analysis, the rate of SO_2 emission reduction from the Billings Refinery significantly outpaces the modest rate of visibility improvement.

[13] The term anthropogenic deciview here is in reference to the definition of “Most impaired days” per 40 CFR 51.301.

[14] The “glidepath” is a straight line of deciviews starting at the baseline (≈ 2000-2004) through the 2064 endpoint of the RHR program. The “endpoint” is the final desired deciviews which represents “remedying of … existing impairment of visibility … which … results from manmade pollution.” (Clean Air Act). If visibility is following this glidepath it is evidence of reasonable progress towards the national goal.

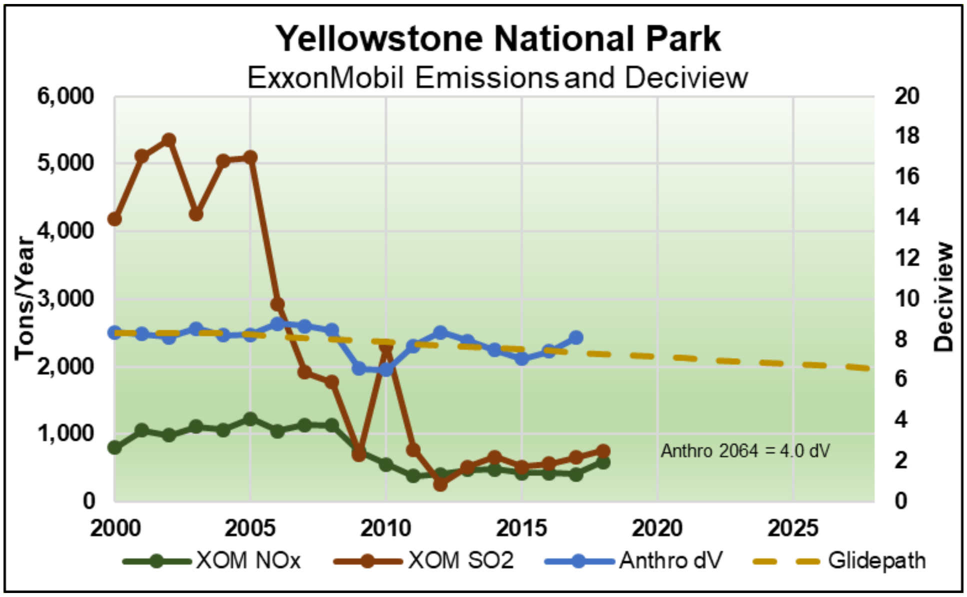

Figure 11: The Billings Refinery SO_2 and NO_x Emissions from 2000 to 2018 compared with the Yellowstone National Park visibility glidepath through 2028

The full correlation analysis results are available in *Appendix A*, but the only slight correlation is between the Billings Refinery NO_x emissions and Anthro dV at an r value of 0.68 (again, both trending downward at a similar slope). However, the r^2 value for those variables indicates that only 32% of the data suggests good linear correlation. Therefore, no evident correlations are seen between the visibility data and the Billings Refinery emissions with the exception of sharing a general downward trend.

4.5.3 UL Bend National Wildlife Refuge Area Visibility vs Emissions

Another Class I area considered is the UL Bend National Wildlife Refuge. This refuge is located about 190 kilometers north/northeast of the Billings Refinery. A graphical review of the emissions and visibility data over time is provided below.

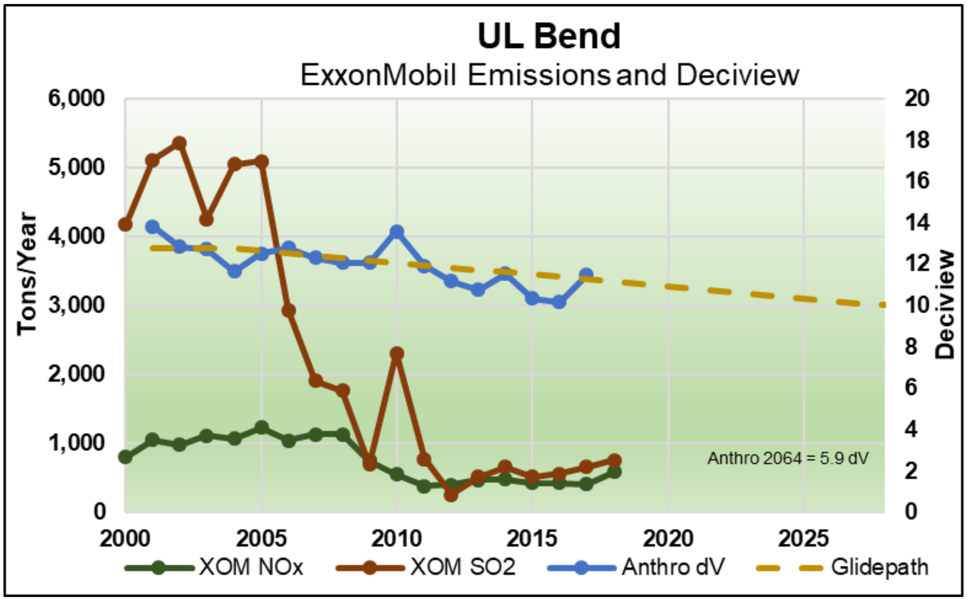

Figure 12: The Billings Refinery SO_2 and NO_x Emissions from 2000 to 2018 compared with the UL Bend National Wildlife Refuge Area visibility glidepath through 2028

The graphic seems to indicate that the glidepath and observed deciview data match relatively closely (see correlation discussion). Thus, data to date shows that the area is meeting the uniform rate of progress (glidepath) that RHR prescribes.

In addition to the graphic, the correlation data in *Appendix A* shows a possible trending relationship between UL Bend's Anthro dV and the Billings Refinery NO_x and SO_2 emissions (at r values of 0.61 and 0.67, respectively), likely because all three were trending down. However, the r^2 data shows that less than 37% and 45% of the data indicate linear correlation. Again, no clear correlations/relationships in data were observed.

4.5.4 Gates of the Mountains Wilderness Area Visibility vs Emissions

The Gates of the Mountains Wilderness Area was selected as another Class I area to review. However, the area is about 270 kilometers west/northwest of the Billings Refinery making it an area very unlikely to be impacted by the Billings Refinery. Nonetheless and review of that data was undertaken. A graphical review of the emissions and visibility data over time is provided below.

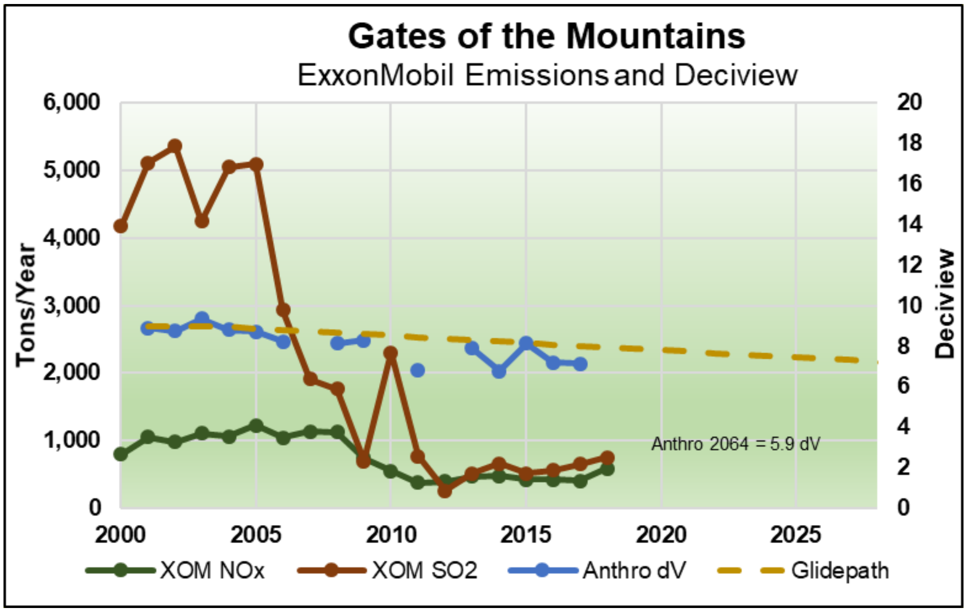

Figure 13: The Billings Refinery SO_2 and NO_x Emissions from 2000 to 2018 compared with Gates of the Mountains Wilderness Area visibility glidepath through 2028

The graphic reveals a few interesting features. First, the rate of emission improvement for the Billings Refinery SO_2 emissions reductions (and to a lesser extent NO_x emissions) is faster than any rate of change for deciviews. Second, the visibility improvement is ahead of the desired uniform rate of progress wanted for the program. Finally, the current visibility (mean for past 5 years) is at or near the desired level for this 2nd planning period.

It is surprising to see an implied correlation between both the Billings Refinery NO_x and SO_2 and Anthro dV (at 0.82 and 0.80) and the Billings Refinery NO_x and SO_2 and Anthro NO_3 and SO_4 (at 0.76 and 0.71). Given the distance and prevailing winds, such a correlation suggests coincidence in trending, not actual relationships between data.

4.5.6 Theodore Roosevelt National Park Visibility vs Emissions

The final Class I area of interest is the Theodore Roosevelt National Park. This Class I area is located approximately 400 kilometers east of the Billings Refinery and is therefore highly unlikely to be impacted by the Billings Refinery SO_2 or NO_x emissions. Nonetheless, because this area has been the subject of interest by the State of North Dakota and EPA Region VIII, it was included in this analysis. The visibility versus emissions information is presented in graphical form below.

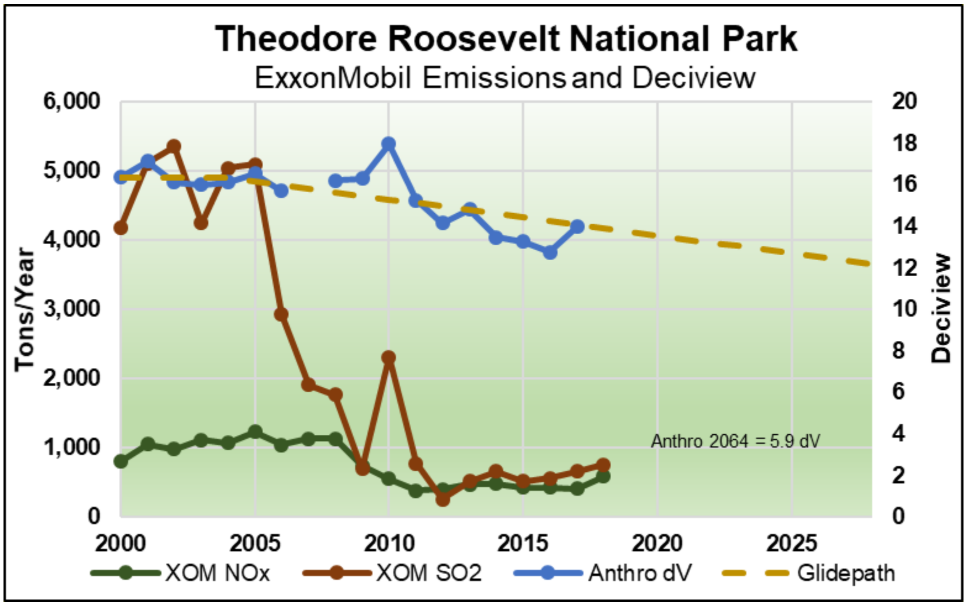

Figure 14: The Billings Refinery SO_2 and NO_x Emissions from 2000 to 2018 compared with Theodore Roosevelt National Park visibility glidepath through 2028

The graphic reveals a faster rate of change (improvement) in the Billings Refinery emissions (particularly SO_2) than a concurrent improvement in visibility. Thus, it would not be logical to equate a change in the Billings Refinery emissions with a measurable improvement in visibility.

Although not specifically portrayed in the graphic, there is a notable trend in visibility improvement in the past 10 years. This corresponds to the same 10-year period of implementation of the 1st planning period. The slope of the emissions from the Billings Refinery, however, do not share this same trend. Again, a reduction in emissions does not seem to suggest an improvement in visibility impairment data.

The r values suggest a potential relationship (the two r values above 0.50 are the Anthro NO_3/Billings Refinery NO_x emissions and Anthro SO_4/Billings Refinery SO_2 emissions at 0.65 and 0.67), both trending downward overall. However, the r^2 values are at 0.42 and 0.45, showing insufficient correlation in the data.

Given the great distances involved and the fact that there is minimal correlation between visibility data and the Billings Refinery emissions, it is reasonable to conclude that the Billings Refinery is not a candidate for emissions reductions to improve visibility at this National Park.

5.0 FOUR-FACTOR ANALYSIS

Per the email from MDEQ dated March 13, 2019, a four-factor analysis was completed for the Billings Refinery. This facility was selected by the MDEQ because of a “Q/d” analysis, used by MDEQ to screen facilities for Round 2.[15] MDEQ’s Q/d analysis used 4.0 as their action threshold for analysis. The Billings Refinery had a Q/d of 7.2. Refineries, such as ExxonMobil’s, are non-typical emissions sources with respect to previous RHR rule analyses because they are made up of many smaller emissions units, as opposed to one or two large emissions sources from other MDEQ identified facilities with Q/d ratios over 4.

Because of this unique emissions unit scenario, for NO_x, this analysis focuses on emissions originating from the KCOB, F-1 /F-401, and the F-551. The KCOB, F-1/F-401, and F-551 are responsible for approximately 52% of the NO_x emissions from the plant based on 2015-2016 emissions baseline. The F-1 Crude Furnace and F-401 Vacuum Heater are two separate units, but they vent to a singular stack, so are evaluated as one unit for the purpose of this analysis. To address potential costs and controls associated with the smaller refinery process heaters, this analysis also includes the F-201 Hydrofiner Heater as a representative smaller process heater. Other NO_x and SO_2 emissions will also be addressed generally and refinery-wide below.

The following outlines the analysis for this source using primarily the direction of the EPA Draft Guidance [10] and the WRAP 2009 four-factor analysis [11]. The initial step in the four-factor analysis was to identify possible additional control options for this source. The options chosen include control techniques addressed in guidelines published by the EPA, the EPA Cost Control Manual, BART analyses, and National Association of Clean Air Agencies (NACAA).

5.1 SO_2 Control Measures

The most common SO_2 control practice that may be applied to typical refinery boilers and other combustion devices (heaters, flares, etc.), specifically those fired with refinery fuel gas, is compliance with the Standards of Performance for Petroleum Refineries (NSPS, 40 CFR 60, Subpart J). That standard includes a hydrogen sulfide content limit of 162 parts per million by volume (ppm_v) or less in refinery fuel gas on a 3-hour rolling average basis. All combustion devices fired with refinery fuel gas at the Billings Refinery are subject to and comply with this standard. In addition, other standards apply including EPA Consent Decree requirements and state SIP requirements. As previously mentioned, MSCC and YELP provide SO_2 control beyond the refinery’s boundaries by extracting sulfur from sour RFG streams and combusting coker process gases, respectively.

5.1.1 SO_2 Four-Factor Analysis and Summary

[15] See email letter from MDEQ dated March 13, 2019

For the 2015-2016 baseline summary, the Billings Refinery averaged 539.42 tons per year of SO_2 emissions with 75% of those emissions attributed to the FCCU. The Billings Refinery is currently working through an extended demonstration period on a desulfurization (DeSOx) additive while operating the FCCU in Full Burn Operation as required under its federal Consent Decree[16] for controlling SO_2 emissions from the FCCU. Given this SO_2 control strategy (and pending final emission limits) between EPA and the Billings Refinery and the significant effort and analysis that went into that process, no further discussion will be provided for SO_2 emission reductions at the Billings Refinery.

The balance of the SO_2 emissions are attributed to either the KCOB (during YELP downtime, particularly in 2016) or small boilers or heaters subject to NSPS Subpart J or other requirements. No additional control is being considered for these units, given the circumstances of the emissions (for the KCOB) and the existing level of control.

5.2 NO_x Control Measures

As previously discussed with respect to SO_2, the EPA Consent Decree included significant emissions reductions for units across the refinery. These reductions included a NO_x Control Plan for heaters and boilers (implementing NO_x controls on at least 30% of the heater and boiler capacity greater than 40 million British Thermal Units per hour, MMBtu/hr) as well as a Selective Catalytic Reduction (SCR) unit installation at the FCCU (with an associated NO_x emission limit). NO_x reductions were evaluated and implemented on units where the investment would provide the most efficient emission reduction value. ExxonMobil has made great efforts through the Consent Decree and beyond, to reduce NO_x emissions in the recent past.

This NO_x analysis focuses on the KCOB, F-1/F-401, and F-551 because these four units are responsible for approximately 52% (220.5 tpy of the total 427.4 tpy) of the NO_x emissions from the plant based on the 2015-2016 emissions baseline. Two other NO_x sources have seen recent emissions control upgrades (F-700 with ULNB) and replacement (B-8 with ULNB and FGR) under the Consent Decree. F-700 and B-8 result in 3% (13.27 tpy) of the 2015-2016 NO_x emissions baseline. Eight other NO_x sources (i.e., small refinery fuel gas-fired heaters less than 40 MMBtu/hr) split the remaining 45% (194 tpy) of the NO_x emissions baseline. As mentioned previously, the F-201 Heater is included in the analysis to show representative costs and controls for the smaller process heaters units less than 40 MMBtu/hr.

There are several ways to control NO_x emissions from a boiler or furnace. Some methods utilize combustion modifications that reduce NO_x formation in the boiler/furnace itself, while others utilize add-on control devices at various points in the exhaust path to remove NO_x after it is formed. Combinations of combustion controls and add-on controls may also be used to reduce NO_x. The identified applicable NO_x control technologies are described below and include: Ultra Low NO_x Burners with Flue Gas Recirculation, Selective Non-Catalytic Reduction (only applicable for boilers, see explanation below), and SCR. The

[16] ExxonMobil Refinery Consent Decree: https://www.epa.gov/enforcement/exxonmobil-refinery-settlement

NO_x basis (the current actual emissions referred to as “uncontrolled emissions” in the EPA cost control spreadsheet) for the KCOB, F-1/F-401, F-551, and F-201 is 0.191, 0.110, 0.107, 0.115 pound per million British Thermal Unit (lb/MMBtu), respectively. These emissions are derived from the pound per million cubic feet emission factor used in annual reporting converted using actual refinery fuel gas heating values.

5.2.1 Combustion Controls – Ultra Low NO_x Burners with Flue Gas Recirculation

Combustion controls are features of the boiler that reduce the formation of NO_x at the source. Ultra-Low NO_x Burners (ULNB) are a common combustion control, particularly for new boilers, which typically include Flue Gas Recirculation (FGR), and are intrinsic to boiler operation when installed. Each is addressed separately below.

5.2.1.1 ULNB

ULNB integrate staged combustion into the burner creating a fuel-rich primary combustion zone. Fuel NO_x formation is decreased by the reducing conditions in the primary combustion zone. Thermal NO_x is limited due to the lower flame temperature caused by the lower oxygen concentration. The secondary combustion zone is a fuel-lean zone where combustion is completed. ULNB may result in increased carbon monoxide (CO) and hydrocarbon emissions, decreased boiler efficiency and increased fuel costs.

5.2.1.2 FGR

FGR is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizers or the air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through absorption of the combustion heat by relatively cooler flue gas. FGR also serves to reduce the oxygen (O_2) concentration in the combustion zone.

Because of the intrinsic nature of both controls (often used in conjunction), they are generally installed in new boilers. While retrofits have occurred (and did, in specific instances during the EPA Refinery Consent Decree NO_x reductions), they generally occurred on smaller, newer, low burner count units. Note: the B-8 Boiler was a full replacement with UNLB and FGR. While EPA has noted efforts to provide cost control information for low NO_x and ultra-low NO_x burners, none has been completed [12].

Based on corporate and unit specific information, F-1/F-401 would not be candidates for ULNB/FGR because of the age of the furnaces. If such an upgrade were required, the furnaces would be replaced, at an estimated cost of $10-$20 million per boiler (F-1 at the higher end, F-401 at the lower end). F-551 would also not be a candidate for UNLB/FGR because of the high number of burners (80). Replacement of 80 burners would essentially require a rebuild of the furnace. Retrofitting the KCOB or F-201 with UNLB/FGR is a potential option, however cost data is difficult to come by, as mentioned above.

For the F-201 and KCOB, the Billings Refinery provided an estimate of UNLB retrofit installation based on actual average costs incurred for similar refinery units in the ExxonMobil fleet. Incorporation of FGR is not included in the estimate because it would require a boiler reconfiguration (and potentially reconstruction).

5.2.2 Selective Non-Catalytic Reduction (SNCR)

Per the April 2019 update of the EPA Cost Control Manual [13], SNCR is a post combustion emissions control technology for reducing NO_x by injecting an ammonia type reactant into the boiler at a properly determined location. This technology is often used for mitigating NO_x emissions since it requires a relatively low capital expense for installation, albeit with relatively higher operating costs. The conventional SNCR process occurs within the combustion unit, which acts as the combustion chamber.

SNCR involves the noncatalytic decomposition of NO_x in the flue gas to nitrogen and water using a reducing agent (e.g., ammonia or urea). The reactions take place at much higher temperatures than in an SCR, typically between 1,550°F and 1,950°F, because a catalyst is not used to drive the reaction. The efficiency of the conversion process diminishes quickly when operated outside the optimum temperature band and additional ammonia slip or excess NO_x emissions may result. Because the viability of SNCR is directly related to combustion temperature, the application of this technology to furnaces/heaters is not technically feasible, as they operate at much lower temperatures (600-700°F). Therefore, SNCR is being analyzed only for the KCOB, not F-1/F-401, F-551 and F-201.

The process has been used in North America since the early 1980s and is most common on utility boilers, specifically coal-fired utility boilers. Removal efficiencies of NO_x vary considerably for this technology, depending on inlet NO_x concentrations, fluctuating flue gas temperatures, residence time, amount and type of nitrogenous reducing agent, mixing effectiveness, acceptable levels of ammonia slip and the presence of interfering chemical substances in the gas stream.

Reagent costs currently account for a large portion of the annual operating expenses associated with this technology and this portion has been growing over time. Ammonia is generally less expensive than urea because urea is derived from ammonia. However, the choice of reagent is based not only on cost but also on physical properties and operational considerations. None of the refinery process units or industrial boilers listed in EPA's applicable information collection request [13,14] used ammonia; all used urea based on the unique operational considerations. Therefore, urea was employed as the reagent in the Billings Refinery SNCR cost analysis for the KCOB.

The median reductions for urea based SNCR systems in various industry source categories range from 25 to 60 percent [14]. Additional industry-specific unit information included in the SNCR White Paper [15], provided boiler size and associated NO_x reductions. In the "Refinery Process Units and Industrial Boiler" section, for units less than 200 MMBtu/hr (the KCOB is rated at 146 MMBtu/hr). The 200 MMBtu/hr was used as a logical cut-off for smaller industrial boilers and the range estimated a 40 to 62.5% NO_x reduction. An average reduction of 58.5% was used in the cost efficiency calculations, for a resulting/predicted exit NO_x emission factor of 0.079 lb/MMBtu at the KCOB.

For SNCR retrofit of existing boilers, optimal locations for injectors may be occupied with existing boiler equipment such as the watertubes. The primary concern is adequate wall space within the boiler for installation of injectors. The injectors are installed in the upper regions of the boiler, the boiler radiant cavity, and the convective cavity. Existing watertubes and asbestos may need to be moved or removed from the boiler housing. In addition, adequate space adjacent to the boiler must be available for the distribution system equipment and for performing maintenance. This may require modification or relocation of other boiler equipment, such as ductwork. The estimated costs on a $/kW basis increase sharply for small boilers (<50 MW) due to both economies of scale and to account for the more difficult installation conditions that are often encountered for the small boilers. The costs provided for SNCR in the Four-Factor Analysis were calculated using EPA's SNCR Cost Calculation Spreadsheet and use the "retrofit factor" of 1 – average retrofit. The Spreadsheet states that its use is particularly for boilers (coal-, oil-, and natural gas-fired) with maximum heat capacities greater than or equal to 250 MMBtu/hr. The KCOB has additional difficulty with respect to boiler ductwork, etc. because of its direct proximity to the coker unit and shared piping/ductwork with that unit. Based on the boiler size, the less-common refinery-fuel gas, the potential for higher retrofit costs, the involvement with the coker unit, and the economies of scale described above, the Billings Refinery believes that the costs calculated are highly conservative (i.e., costs are estimated low). As shown in Table 2 below, EPA's estimates compared to actual costs incurred for similar refinery units in the ExxonMobil fleet are quite low and do not consider the significant and unique complexities associated with retrofitting refinery units.

5.2.3 Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment technique for reduction of NO and NO_2 in an exhaust stream to molecular nitrogen, water, and oxygen. Ammonia (NH_3) or urea is used as the reducing agent.

SCR is typically implemented on stationary source combustion units requiring a higher level of NO_x reduction than may be achievable by SNCR or combustion controls. In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NO_x controls such as Low NO_x Burner (LNB) or FGR that achieve relatively low emissions on their own [15,16]. The controlled SCR emissions rates used in the analysis are based on a 95% control efficiency. Actual control efficiency rates may vary based on configuration and unit type.

With respect to reagents, either ammonia or urea may be used as the NO_x reduction reagent in SCR systems. Urea is generally converted to ammonia before injection. Results of a survey of electric utilities that operate SCR systems indicated 80 percent use ammonia (anhydrous and aqueous), and the remainder use urea [17]. Additionally, a survey of coal-fired power plants that control NO_x emissions using either SCR or SNCR found anhydrous ammonia use exceeds aqueous ammonia use by a ratio of 3 to 1 [17]. Nearly half of these survey respondents indicated that price is their primary consideration in the choice of reagent with safety second. Because ammonia is most commonly used (and is the default for the EPA's SCR Cost Calculation Spreadsheet), it was used in the reagent calculations for the KCOB, F-1/F-401, F-551, and F-201 [18].

Ammonia or urea is injected into the flue gas upstream of a catalyst bed, and NO_x and NH_3 combine at the catalyst surface, forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Typical catalyst materials include metal oxides (e.g., titanium oxide and vanadium), noble metals (e.g., platinum and rhodium), zeolite, and ceramics.

The control technology works best for flue gas temperatures between 575°F and 750°F. Excess air is injected at the boiler exhaust to reduce temperatures to the optimum range, or the SCR is located in a section of the boiler exhaust ducting where the exhaust temperature has cooled to this temperature range. Technical factors that impact the effectiveness of this technology include inlet NO_x concentrations, the catalyst reactor design, operating temperatures and stability, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, catalyst age and reactivity, and the potential for catalyst poisoning.

Typically, installation of the SCR is upstream of the particulate control device (e.g., baghouse). SCRs are classified as a low or high dust SCR. A low dust SCR is usually applied to natural gas combustion units or after a particulate control device. For this application, both boilers combust clean fuels (refinery fuel gas), and particulate loading is not anticipated to be a problem, therefore a low dust SCR would be appropriate

In retrofit installations, new ductwork would be required to integrate the SCR system with the existing equipment. In low-dust SCR systems for utility and industrial boilers, the SCR reactor would be located between the outlet duct of the particulate control device (not applicable for this purpose) and the air heater inlet duct.

Retrofit of SCR on an existing unit has higher capital costs than SCR installed on a new system. There is a wide range of SCR retrofit costs due to site-specific factors, scope differences, and site congestion [19]. Specific factors that impact the retrofit costs include the following [17]:

- Amount of available space between and around the economizer and air heater;
- Congestion downstream of the air heater (i.e., buildings, conveyors, existing particulate control devices, if applicable; induced draught (ID) fan, or stack);
- Age/vintage and manufacturer of the boiler;
- Design margin of the existing ID fan (i.e., the need to upgrade or replace fan impellers, replace ID fans, or add booster fans);
- Capacity, condition, and design margins of the electrical distribution system;

- Design margins of the existing structural steel support systems;
- The positive and negative design pressure of the furnace;
- Number, nature, and type of existing items that must be relocated to accommodate the SCR and associated systems; and
- Based on ExxonMobil corporate experience: foundations, ducting, and wiring.

As previously discussed for SNCR, there is an efficiency of scale associated with pollution control equipment installation. Because the cost calculator is based on units with a heat capacity greater than 250 MMBtu/hr (and only one unit, the combined F-1/F-401 is in that size range at 280 MMBtu/hr), those efficiencies are included in the EPA spreadsheet estimates. The costs provided for SCR in the four-factor analysis that follows are calculated using EPA's SCR Cost Calculation Spreadsheet also use the "retrofit factor" of 1 – average retrofit. Based on the boiler size, the less-common refinery-fuel gas, the potential for higher retrofit costs, and the economies of scale described above, the Billings Refinery believes that the costs calculated for SCR are also highly conservative (i.e., costs are estimated low). As shown in Table 2 below, EPA's estimates compared to actual costs incurred for similar refinery units in the ExxonMobil fleet are quite low and do not take into account the significant and unique complexities associated with retrofitting refinery units.

5.3 Four-Factor Analysis and Summary - NO_x

5.3.1 Factor 1 – Cost of Compliance

The cost of compliance estimates the capital cost of purchasing and installing new control equipment along with the annual operation and maintenance (O&M) cost as generally outlined in EPA Draft Guidance. These categories of costs include categories such as direct capital cost, indirect capital cost, labor cost, contingency cost, and annual cost. Methodologies given in the EPA Air Pollution Control Cost Manual (Control Cost Manual) are the indicated reference for determining the cost of compliance for SNCR and SCR [20].

Costs were expressed in terms of cost-effectiveness in a standardized unit of dollars per ton of actual emissions reduced by the proposed control option. Baseline emissions for the KCOB, F-1/F-401, F-551, and F-201 were taken from the baseline 2015 and 2016 annual emission inventory years it relates to Round 2[17].

The capital recovery factor was applied to the control options based on a 20-year equipment life expectancy and applying the 5.5% as the interest rate noted by MDEQ in their April 19, 2019 email correspondence. The resulting cost of compliance, based on EPA's cost control manual, is presented in Table 4.1. Details of the EPA calculations may be found in *Appendix A*. The ExxonMobil cost effectiveness estimates are based on similar unit upgrades (or averages of similar unit upgrades, with allowances for unique Billings space or needs) elsewhere in the ExxonMobil refinery fleet. Specific retrofit costs

[17] See email letter from MDEQ dated July 9, 2019

would require a detailed engineering analysis of the actual site (for space considerations), unit, and process considerations.

Table 2: Estimated Costs of NO_x Control Options for the Billings Refinery, ranked by Control Efficiency

Source	Potential Control Option	Estimated Control Efficiency (%)	Potential Emission Reduction (tons/year)	EPA Total Annual Cost (in 2018 dollars)[a]	Cost Effectiveness ($/ton) based on EPA spreadsheet/ retrofit factor[a]	Estimated ExxonMobil Retrofit Factor[e]	Anticipated Actual Cost Effectiveness ($/ton) [b]
KCOB (146 MMBtu/hr, refinery fuel gas fired)	SNCR	58.5	30	$231,203	$7,698	--	--
	UNLB	~85	62	--[d]	--[d]	--	$5,800[c]
	SCR	95	67	$438,842	$6,564	3.7	$24,300
F-1/F-401 (280 MMBtu/hr, refinery fuel gas fired, total)	SCR	95	79	$687,812	$8,732	3.7	$32,300
F-551 (160 MMBtu/hr, refinery fuel gas fired)	SCR	95	51	$474,103	$9,290	3.7	$34,400
F-201(36 MMBtu/hr, refinery fuel gas fired)	UNLB	~78	~7	--[d]	--[d]	--	$31,100[c]
	SCR	95	~9	$169,512	$18,919	3.7	$70,000

a. Based on EPA Cost Control Spreadsheets 2019.
b. Based on ExxonMobil corporate project information.
c. The UNLB cost assumes no major physical changes to boiler or boiler configuration (e.g., due to spacing of burners).
d. As discussed in Section 5.2.1, EPA does not have ULNB costs in its cost control manual at this time.
e. ExxonMobil retrofit factors ranged from approximately 3.7 to 10.

As discussed below, EPA uses a standard retrofit factor of 1 that does not account for refinery-specific complications. An actual retrofit factor is calculated in Table 2 above based on the ratio of the EPA cost control spreadsheet value versus the ExxonMobil estimate. However, even at the EPA cost control spreadsheet levels (and decisively at the ExxonMobil cost estimate levels), the costs for additional control at the KCOB, F-1/F-401, F-551, F-201 (and similar units) are cost prohibitive. Initial discussions with MDEQ indicated "Best Available Control Technology (BACT) level" costs would be considered for the four-factor analysis process. As previously discussed, apart from the "combined" F-1/F-401, the EPA calculated costs above incorporate the economies of scale associated with much larger units than the KCOB and F-551 and use an "average" retrofit factor. EPA also anticipates such retrofits are to be much more costly/more complex higher on smaller boilers. The EPA retrofit factor is generally associated with utility units, not the significantly more complex refinery units with respect to process integration, piping, and safety. The 3.7 retrofit factor shown in Table 2 above is based on completed retrofit projects at similar units using SCR within the ExxonMobil fleet. The actual ExxonMobil retrofit factors range from 3.7 to nearly 10 because of refinery-specific retrofit challenges. Specific refinery issues include limited space/footprint within the refinery boundary, foundation requirements based on limited footprints and type of SCR used (i.e., low, medium, or high temperature), extensive additional requirements and capital associated with the American Petroleum Institute piping codes, and the specific electrical classifications in both equipment and control centers (including monitoring, etc.) to ensure intrinsic safety in the complex refinery environment. However, even at this conservatively low level, even EPA's costs exceed BACT level cost per ton values at recently permitted units, even under major source permitting efforts.

5.3.2 Factor 2 – Time Necessary for Compliance

The Billings Refinery relies on the consistent operation of the crude unit (F-1/F-401), the KCOB (associated with the Coker Unit and steam production necessary for the refinery) and the hydrogen plant (F-551); all of these units are intrinsic to refinery operation. Therefore, any major retrofits or maintenance on major refinery units is scheduled during periodic maintenance turnarounds. Any major control installation at affected units would have to wait until either the estimated 2026 Hydrogen Plant/Hydrocracker turnaround (affecting the F-551 Heater) or the estimated 2025 FCCU/Alkylation Unit turnaround. The retrofit of smaller process heaters (such as F-201) may allow for implementation outside of major turnarounds, but such efforts would require a similar level of planning as the major units because of the interdependence of refinery systems.

EPA does not provide a specific time necessary for compliance basis for replacement of existing burners/boiler configurations with ULNB/FGR. The closest reference EPA provides is in its July 2010 Technical Support Document (TSD) for the Transport Rule – Installation Timing for Low NO_x Burners (LNB) [21]. That document stated that in one instance, an 820 MW tangentially fired lignite unit was retrofitted with an LNB system in less than six months, including engineering, fabrication, delivery and installation. EPA, in that same document, stated that LNB installations accomplished in less than a year were "aggressive." Given that information, ULNB/FGR installation with permitting would likely be 18-24 months, without considering refinery turnarounds.

For SNCR on the KCOB, EPA states in its Cost Control Manual, "Installation of SNCR equipment requires minimum downtime. Although simple in concept, it is challenging in practice to design an SNCR system that is reliable, economical, and simple to control and that meets other technical, environmental, and regulatory criteria. Practical application of SNCR is limited by the boiler design and operating conditions."[13] EPA also states in its 2008 Electric Generating Unit (EGU) NO_x Mitigation Strategies Proposed Rule TSD for the Cross State Air Pollution Rule for the 2008 Ozone National Ambient Air Quality Standards (NAAQS) [22], that "SNCR … requires 12 months from contract award through commissioning." In addition, SNCR would require additional time for "conceptual design, permitting, financing, and bid review." Given that, the Billings Refinery is estimating SNCR would require approximately 3-5 years for design, permitting, financing, etc. through commissioning.

For SCR, as previously mentioned, EPA states in its Cost Control Manual, "In retrofit installations, new ductwork is required to integrate the SCR system with the existing equipment."[17] Because the KCOB, F-1/F-401, F-551, F-201 are primarily refinery fuel gas-fired units and have negligible particulate emissions, consideration of high-dust SCRs would not be necessary, and the focus would be on either low-dust or tail-end installations (tail-end refers to following all pollution control devices; for the units in question, the options would be essentially the same). "In low-dust SCR systems for utility and industrial boilers, the SCR reactor is located between the outlet duct of the particulate control device and the air heater inlet duct. In tail-end SCR systems for utility and industrial boilers, the ductwork tie-ins are downstream of the flue gas desulfurization (FGD) system and also require the integration of the flue gas reheating equipment."[17] EPA also states in the TSD for the Cross State Air Pollution Rule for the 2008 Ozone NAAQS [22], that "The time requirements for an SCR retrofit exceeds 18 months from contract award through commissioning." In addition, SCR would also require additional time for "conceptual design, permitting, financing, and bid review." [22] Given that, the Billings Refinery is estimating SCR would require approximately 3-5 years months for design, permitting, financing, etc. through commissioning. If PSD permitting is triggered on the basis of formation of condensable particulate matter from the SCR (see below), the timeline would be extended beyond that estimate.

5.3.3 Factor 3 – Energy and Non-air Environmental Impacts

In general, the use of combustion controls for reducing NO_x formation can have a slightly adverse effect on the formation of CO.

SCR and SNCR both present several adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and the products of secondary reactions between ammonia and other species present in the flue gas will be emitted to the atmosphere. Ammonia slip causes the formation of additional condensable particulate matter such as ammonium sulfate, $(NH_4)_2SO_4$. The ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume. In addition, SCR would require disposal or recycling of catalyst materials, which may require handling in a specific landfill for hazardous waste.

Energy impacts are included in annual operation and maintenance costs.

5.3.4 Factor 4 – Remaining Useful Life of Source

None of the units considered (KCOB, F-1/F-401, F-551, or F-201) are planned for retirement at this time. Therefore, as dictated in discussions and correspondence with MDEQ, the remaining useful life of the sources is assumed to be 20 years.

6.0 CONCLUSIONS

A four-factor analysis at the Billings Refinery was conducted to meet the requirements of Round 2 to develop a SIP to address Regional Haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308(d)(1). To implement the requirement, MDEQ requested this analysis from the Billings Refinery.

The four factors analyzed were based on the MDEQ correspondence and the RHR to determine if there are emission control options at the Billings Refinery that, if implemented, could be used to attain reasonable progress toward the state's visibility goals. The factors reviewed included the cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and the remaining useful life of the existing source subject to these requirements.

The four-factor analysis was conducted for NO_x on KCOB, F-1 /F-401, F-551, and F-201 (representing smaller refinery process heaters) at the Billings Refinery with additional discussion regarding facility-wide emissions reduction efforts for both NO_x and SO_2. The Billings Refinery has made considerable investment in reducing emissions through the Refinery Consent Decree process (that is still ongoing with respect to the FCCU) as well as corporate efficiency initiatives and continues to be a good environmental steward. The downward trend in visibility-impairing pollutants, both NO_x and SO_2, was apparent in Section 3 of this analysis, as was the lack of correlation between the Billings Refinery emissions and visibility in nearby Class I areas.

With respect to the purpose of this analysis, the RHR [§308(d)] outlines what it refers to as: "the core requirements" for the implementation of the regional haze goals. More specifically, §308(d)(1) states:

> "*For each mandatory Class I Federal area . . ., the State must establish goals . . . that provide for reasonable progress towards achieving natural visibility conditions.* ***The reasonable progress goals must provide for an improvement in visibility*** *for the most impaired days..."* [40 CFR 51.308(d)(1)].

Reasonable progress is tied to an improvement in visibility, not costly pollution control without benefit. The results of the analysis have indicated that additional controls on KCOB, F-1 /F-401, F-551, and F-201 (and similar smaller process heaters) are not necessary to make reasonable progress due to costs and the Billings Refinery's lack of measurable impact on any nearby Class I area, particularly in light of recent emissions reductions by the Billings Refinery and other regional and state facilities. It is concluded that this facility does not qualify for additional emission controls or limitations based on this analysis.

7.0 REFERENCES

1. "*State of Montana Regional Haze, 5-Year Progress Report*," MDEQ, August 2017. Available at: http://deq.mt.gov/Portals/112/Air/AirQuality/Documents/RegionalHaze/RegionalHaze_ProgressReport_8-2017.pdf

2. Interagency Monitoring of Protected Visual Environments (IMPROVE) data. Available at: http://vista.cira.colostate.edu/Improve/

3. IMPROVE data, anthropogenic regional haze degradation. Available at: http://vista.cira.colostate.edu/improve/wp-content/uploads/2019/02/2016-IMPROVE-NR-Bext-SIA-Annual-IG90-w-Canada-vers-1.jpg

4. Montana Department of Environmental Quality (MDEQ) Clean Air Act Advisory Council Presentation, February 2019. Available at: http://deq.mt.gov/Portals/112/Air/AirQuality/Documents/CAAAC/PDF/Feb7_2019/2019-0207_CAAAC_Slides.pdf

5. 40 CFR 51.308(d)(1). Available at: https://www.ecfr.gov/cgi-bin/text-idx?SID=0a3659152f4bc281ef6e664811f7d1c6&mc=true&node=se40.2.51_1308&rgn=div8

6. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019. Available at: https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

7. 40 CFR 51.308, *et seq*. Available at: https://www.ecfr.gov/cgi-bin/text-idx?SID=425a446cac061ec78025c5777544f375&mc=true&node=se40.2.51_1308&rgn=div8

8. Western Regional Air Partnerships (WRAP), Regional Haze efforts. Available at: http://www.wrapair2.org/reghaze.aspx

9. IMPROVE Program, Regional Haze efforts. Available at: http://vista.cira.colostate.edu/Improve/improve-program/

10. "*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,*" EPA, EPA-457/P-16-001, July 2016. Available at: https://www.epa.gov/sites/production/files/2016-

07/documents/draft_regional_haze_guidance_july_2016.pdf

11. "*Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota",* Brad Nelson, William Battye, Janet Hou, EC/R Incorporated, Western Regional Air Partnership (WRAP) and Western Governors' Association (WGA), May 18, 2009.

12. Current timeline for Activities Needed for Development of EPA Air Pollution Control Cost Manual, 7th Edition, December 2017. Available at: https://www.epa.gov/sites/production/files/2017-12/documents/controlcostmanualupdatepublictimelinedecember2017vf.pdf

13. EPA Cost Control Manual (Seventh Edition), Section 4 – NO_x Controls, Chapter 1 – Selective Non-Catalytic Reduction, April 25, 2019. Available at: https://www.epa.gov/sites/production/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf

14. U. S. Environmental Protection Agency. Petroleum Refinery Database, Based on Refinery Information Collection Request (ICR) for Calendar Year 2010. March 31, 2011. Docket No. EPA-HQ-OAR-2010-0682.

15. Institute of Clean Air Companies (ICAC), Selective Non-Catalytic Reduction (SNCR) for controlling NO_x Emissions; White Paper. Prepared by the SNCR Committee of ICAC. February 2008. Available at: https://cdn.ymaws.com/icac.site-ym.com/resource/resmgr/Standards_WhitePapers/SNCR_Whitepaper_Final.pdf

16. ICAC, Selective Catalytic Reduction (SCR) for Controlling NO_x Emissions from Fossil Fuel-Fired Electric Power Plants, Institute of Clean Air Companies, May 2009. Available at: https://cdn.ymaws.com/www.icac.com/resource/resmgr/Standards_WhitePapers/SCR_WhitePaper_final_2009.pdf

17. EPA Cost Control Manual (Seventh Edition), Section 4 – NO_x Controls, Chapter 2 – Selective Catalytic Reduction (updated on June 12, 2019). Available at: https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

18. EPA's SCR Cost Calculation Spreadsheet, June 2019. Available at: https://www.epa.gov/sites/production/files/2019-06/scrcostmanualspreadsheet_june-2019vf.xlsm

19. Uniqueness of SCR Retrofits Translates into Broad Cost Variations. Washington Group International. Power Engineering. May 2003. http://pepei.pennnet.com/display_article/176832/6/ARTCL/none/none/1/Uniqueness-

ofSCR-Retrofits-Translates-into-Broad-Cost-Variations/

20. EPA Cost Control Manual (seventh edition), November 2017: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

21. Technical Support Document for the Transport Rule – Installation Timing for Low NOx Burners, July 2010, https://www.epa.gov/sites/production/files/2017-06/documents/epa-hq-oar-2009-0491-0051.pdf

22. EGU NO_x Mitigation Strategies Proposed Rule TSD, September 2015, https://www.epa.gov/sites/production/files/2015-11/documents/egu_nox_mitigation_strategies_tsd_0.pdf

APPENDIX A: CORRELATION ANALYSES

APPENDIX B: COST ANALYSES

APPENDIX A: CORRELATION ANALYSES

Visibility and SO_2 Correlation Calculations

North Absaroka Wilderness Area

		Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*XOM SO_2*
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Billings SO_2	0.77	-0.16	1			
	Glidepath	0.80	-0.11	0.95	1		
	Anthro SO_4	0.62	-0.25	0.74	0.83	1	
	XOM SO_2	0.71	-0.19	0.95	0.87	0.62	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.07	1				
	Billings SO_2	0.59	0.03	1			
	Glidepath	0.64	0.01	0.90	1		
	Anthro SO_4	0.39	0.06	0.55	0.69	1	
	XOM SO_2	0.51	0.04	0.91	0.76	0.38	1

Visibility and SO_2 Correlation Calculations

Yellowstone National Park

		Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*XOM SO_2*
r =	Year						
	Anthro dV	1					
	All dV	0.45	1				
	Billings SO_2	0.46	-0.23	1			
	Glidepath	0.48	-0.25	0.95	1		
	Anthro SO_4	0.47	-0.13	0.51	0.66	1	
	XOM SO_2	0.43	-0.28	0.95	0.87	0.43	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.20	1				
	Billings SO_2	0.21	0.05	1			
	Glidepath	0.23	0.06	0.90	1		
	Anthro SO_4	0.22	0.02	0.26	0.44	1	
	XOM SO_2	0.18	0.08	0.91	0.76	0.18	1

Visibility and SO_2 Correlation Calculations

UL Bend Wilderness Area

		Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*XOM SO_2*
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Billings SO_2	0.70	0.04	1			
	Glidepath	0.74	0.07	0.95	1		
	Anthro SO_4	0.70	-0.08	0.41	0.51	1	
	XOM SO_2	0.67	0.07	0.95	0.86	0.36	1

		Anthro dV	All dV	Billings SO_2	Glidepath	Anthro SO_4	XOM SO_2
r2 =	Year						
	Anthro dV	1					
	All dV	0.07	1				
	Billings SO_2	0.49	0.00	1			
	Glidepath	0.55	0.00	0.90	1		
	Anthro SO_4	0.49	0.01	0.17	0.26	1	
	XOM SO_2	0.45	0.00	0.91	0.74	0.13	1

Visibility and SO_2 Correlation Calculations

Gates of the Mountains Wilderness Area

		Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*XOM SO_2*
r =	Year						
	Anthro dV	1					
	All dV	-0.09	1				
	Billings SO_2	0.81	-0.22	1			
	Glidepath	0.82	-0.29	0.95	1		
	Anthro SO_4	0.69	-0.37	0.77	0.90	1	
	XOM SO_2	0.80	-0.10	0.95	0.87	0.71	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.01	1				
	Billings SO_2	0.66	0.05	1			
	Glidepath	0.68	0.08	0.90	1		
	Anthro SO_4	0.48	0.14	0.59	0.81	1	
	XOM SO_2	0.63	0.01	0.91	0.76	0.50	1

Visibility and SO_2 Correlation Calculations

Theodore Roosevelt National Park

		Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*XOM SO_2*
r =	Year						
	Anthro dV	1					
	All dV	0.75	1				
	Billings SO_2	0.72	0.55	1			
	Glidepath	0.79	0.62	0.95	1		
	Anthro SO_4	0.88	0.61	0.53	0.63	1	
	XOM SO_2	0.67	0.55	0.95	0.87	0.48	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.57	1				
	Billings SO_2	0.52	0.30	1			
	Glidepath	0.62	0.38	0.90	1		
	Anthro SO_4	0.77	0.37	0.28	0.40	1	
	XOM SO_2	0.45	0.30	0.91	0.76	0.23	1

Visibility and NOx Correlation Calculations

North Absaroka Wilderness Area

		Anthro dV	*All dV*	*Billings NOx*	*Glidepath*	*Anthro NO_3*	*XOM NOx*
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Billings NOx	0.74	-0.12	1			
	Glidepath	0.80	-0.11	0.96	1		
	Anthro NO_3	0.53	-0.40	0.78	0.76	1	
	XOM NOx	0.68	-0.10	0.82	0.83	0.65	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.07	1				
	Billings NOx	0.54	0.02	1			
	Glidepath	0.64	0.01	0.92	1		
	Anthro NO_3	0.28	0.16	0.60	0.57	1	
	XOM NOx	0.46	0.01	0.66	0.69	0.42	1

Visibility and NOx Correlation Calculations

Yellowstone National Park

		Anthro dV	*All dV*	*Billings NOx*	*Glidepath*	*Anthro NO_3*	*XOM NOx*
r =	Year						
	Anthro dV	1					
	All dV	0.45	1				
	Billings NOx	0.53	-0.22	1			
	Glidepath	0.48	-0.25	0.96	1		
	Anthro NO_3	0.37	-0.07	0.60	0.57	1	
	XOM NOx	0.57	-0.22	0.82	0.83	0.42	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.20	1				
	Billings NOx	0.28	0.05	1			
	Glidepath	0.23	0.06	0.92	1		
	Anthro NO_3	0.14	0.01	0.36	0.32	1	
	XOM NOx	0.32	0.05	0.66	0.69	0.18	1

Visibility and NOx Correlation Calculations

UL Bend Wilderness Area

		Anthro dV	*All dV*	*Billings NOx*	*Glidepath*	*Anthro NO_3*	*XOM NOx*
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Billings NOx	0.72	0.08	1			
	Glidepath	0.74	0.07	0.97	1		
	Anthro NO_3	0.77	0.23	0.39	0.45	1	
	XOM NOx	0.61	0.18	0.82	0.86	0.35	1

		Anthro dV	All dV	Billings NOx	Glidepath	Anthro NO_3	XOM NOx
r2 =	Year						
	Anthro dV	1					
	All dV	0.07	1				
	Billings NOx	0.51	0.01	1			
	Glidepath	0.55	0.00	0.94	1		
	Anthro NO_3	0.59	0.05	0.15	0.20	1	
	XOM NOx	0.37	0.03	0.66	0.74	0.12	1

Visibility and NOx Correlation Calculations

Gates of the Mountains Wilderness Area

		Anthro dV	*All dV*	*Billings NOx*	*Glidepath*	*Anthro NO_3*	*XOM NOx*
r =	Year						
	Anthro dV	1					
	All dV	-0.09	1				
	Billings NOx	0.79	-0.26	1			
	Glidepath	0.82	-0.29	0.97	1		
	Anthro NO_3	0.78	-0.11	0.79	0.84	1	
	XOM NOx	0.82	-0.13	0.82	0.82	0.76	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.01	1				
	Billings NOx	0.62	0.07	1			
	Glidepath	0.68	0.08	0.93	1		
	Anthro NO_3	0.61	0.01	0.62	0.71	1	
	XOM NOx	0.68	0.02	0.66	0.67	0.58	1

Visibility and NOx Correlation Calculations

Theodore Roosevelt National Park

		Anthro dV	*All dV*	*Billings NOx*	*Glidepath*	*Anthro NO_3*	*XOM NOx*
r =	Year						
	Anthro dV	1					
	All dV	0.75	1				
	Billings NOx	0.76	0.58	1			
	Glidepath	0.79	0.62	0.96	1		
	Anthro NO_3	0.89	0.70	0.65	0.62	1	
	XOM NOx	0.65	0.55	0.82	0.83	0.53	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.57	1				
	Billings NOx	0.58	0.34	1			
	Glidepath	0.62	0.38	0.92	1		
	Anthro NO_3	0.79	0.49	0.42	0.38	1	
	XOM NOx	0.42	0.30	0.66	0.69	0.28	1

APPENDIX B: COST ANALYSES

KCOB SNCR Analysis

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 146 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,096 Btu/scf

What is the estimated actual annual fuel consumption? 674,000,000 scf/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	265	days	
Plant Elevation	3085	Feet above sea level	
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.191	lb/MMBtu	
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.079	lb/MMBtu	
Estimated Normalized Stoichiometric Ratio (NSR)	2.00		*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).
Concentration of reagent as stored (C_{stored})	50	Percent	
Density of reagent as stored (ρ_{stored})	71	lb/ft^3	
Concentration of reagent injected (C_{inj})	50	percent	
Number of days reagent is stored ($t_{storage}$)	14	days	
Estimated equipment life	20	Years	
Select the reagent used	Urea		

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2018			
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI
Annual Interest Rate (i)	5.5	Percent*		
Fuel ($Cost_{fuel}$)	2.87	$/MMBtu*		
Reagent ($Cost_{reag}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

CEPCI = Chemical Engineering Plant Cost Index

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	146	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	1,166,934,307	scf/Year	
Actual Annual fuel consumption (Mactual) =		674,000,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.42	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	3673	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	59	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	16.35	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	30.03	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.12		
Atmospheric pressure at 3085 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.1	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	36	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	73	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	7.7	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	2,600	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	3.2	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.03	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$564,352 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	\$857,663 in 2018 dollars
Total Capital Investment (TCI) =	\$1,848,620 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$564,352 in 2018 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})
For Coal-Fired Utility Boilers:
$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$
For Fuel Oil and Natural Gas-Fired Utility Boilers:
$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$
For Coal-Fired Industrial Boilers:
$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$
For Fuel Oil and Natural Gas-Fired Industrial Boilers:
$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$

Balance of Plant Costs (BOP_{cost}) =	$857,663	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$75,642	in 2018 dollars
Indirect Annual Costs (IDAC) =	$155,561	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$231,203	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$27,729	in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$46,774	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$794	in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$345	in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2018 dollars
Direct Annual Cost =		$75,642	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$832	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$154,729	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$155,561	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$231,203	per year in 2018 dollars
NOx Removed =	30	tons/year
Cost Effectiveness =	$7,698	per ton of NOx removed in 2018 dollars

KCOB SCR Analysis

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

What type of fuel does the unit burn? Natural Gas

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 146 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,096 Btu/scf

What is the estimated actual annual fuel consumption? 674,000,000 scf/Year

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 3085 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	211	days
Number of days the boiler operates (t_{plant})	211	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.191	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.01	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)		Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)		acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})		ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018		
CEPCI for 2018	603.1	Enter the CEPCI value for 2018 / 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh	* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	146	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,166,934,307	scf/Year	
Actual Annual fuel consumption (Mactual) =		674,000,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.578	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5060	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	94.8	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	26.43	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	66.85	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.18		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	60,000	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	96.07	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.12		
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	13.1	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.1792	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	624.57	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	63	ft^2

Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst}$	72	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	8.5	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	54	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	10	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	35	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,600	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	75.07	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$4,463,319	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$63,476	in 2018 dollars
Indirect Annual Costs (IDAC) =	$375,367	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$438,842	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$22,317	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$7,013	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$25,677	in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$8,469	in 2018 dollars
Direct Annual Cost =		$63,476	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$1,787	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$373,580	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$375,367	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$438,842	per year in 2018 dollars
NOx Removed =	67	tons/year
Cost Effectiveness =	$6,564	per ton of NOx removed in 2018 dollars

F-1/F-401 SCR Analysis

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	280	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	20,791	Btu/lb
What is the estimated actual annual fuel consumption?	72,539,079	scf/year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	3085	Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Bituminous

Enter the sulfur content (%S) = 1.00 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ● Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	262 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	262 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.10996 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0055 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours		
Estimated SCR equipment life	20 Years*	Gas temperature at the SCR inlet (T)	650 ^oF
* For industrial boilers, the typical equipment life is between 20 and 25 years.		Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1 Enter the CEPCI value for 2018 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5 Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676 $/kWh	* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	11,841	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	280	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	117,974,123	scf/year	
Actual Annual fuel consumption (Mactual) =		72,539,079	scf/year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.615	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5386	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	95.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	29.25	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	78.77	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.19		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	129,679	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	111.22	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.12		
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	13.1	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.2303	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	1,165.95	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	135	ft^2

Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst}$	155	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	12.5	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	53	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	11	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	39	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,800	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(\text{CoalF} \times \text{HRF})^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	143.97	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$0	in 2018 dollars
Reagent Preparation Cost (RPC) =	$0	in 2018 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2018 dollars
Balance of Plant Costs (BPC) =	$0	in 2018 dollars
Total Capital Investment (TCI) =	$0	in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$0 in 2018 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$0 in 2018 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)
For Coal-Fired Utility Boilers >25MW:
$BPC = 529{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$
For Coal-Fired Industrial Boilers >250 MMBtu/hour:
$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$

Balance of Plant Costs (BOP_{cost}) =	$0 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$115,081	in 2018 dollars
Indirect Annual Costs (IDAC) =	$572,731	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$687,812	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$34,076	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$8,263	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$52,423	in 2018 dollars
Annual Catalyst Replacement Cost =		$20,318	in 2018 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$115,081	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,295	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$570,436	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$572,731	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$687,812	per year in 2018 dollars
NOx Removed =	79	tons/year
Cost Effectiveness =	$8,732	per ton of NOx removed in 2018 dollars

F-551 SCR Analysis

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	160	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,096	Btu/scf
What is the estimated actual annual fuel consumption?	913,000,000	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 3085 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	261	days
Number of days the boiler operates (t_{plant})	261	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.107	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.005	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)		Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)		acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})		ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018		
CEPCI for 2018	603.1	Enter the CEPCI value for 2018 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	\$/gallon for 29% ammonia*	* \$0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	\$/kWh	* \$0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	\$/hour (including benefits)*	* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	-	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	160	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,278,832,117	scf/Year	
Actual Annual fuel consumption (Mactual) =		913,000,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.714	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6254	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	95.3	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	16.32	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	51.03	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.19		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	60,000	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	89.91	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.12		
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	13.1	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.2303	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	667.34	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	63	ft^2

Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	5	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	72	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	8.5	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	55	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	6	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	22	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,000	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(\text{CoalF x HRF})^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	82.27	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$4,737,035	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$75,450 in 2018 dollars
Indirect Annual Costs (IDAC) =	$398,653 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$474,103 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$23,685 in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$5,354 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$34,782 in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$11,629 in 2018 dollars
Direct Annual Cost =		$75,450 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,163 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$396,490 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$398,653 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$474,103 per year in 2018 dollars
NOx Removed =	51 tons/year
Cost Effectiveness =	$9,290 per ton of NOx removed in 2018 dollars

F-201 SCR Analysis

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 36 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,096 Btu/scf

What is the estimated actual annual fuel consumption? 150,000,000 scf/Year

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 3085 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	190	days
Number of days the boiler operates (t_{plant})	190	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.115	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.006	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)		Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)		acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})		ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018		
CEPCI for 2018	603.1	Enter the CEPCI value for 2018 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh	* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	-	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	36	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	287,737,226	scf/Year	
Actual Annual fuel consumption (Mactual) =		150,000,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.521	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4567	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	94.8	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	3.92	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	8.96	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.18		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	60,000	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	400.23	/hour	
Residence Time	$1/V_{space}$	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.12		
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	13.1	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.1792	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	149.92	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	63	ft^2

Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst})) + 1$ (rounded to next highest integer)	2	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst}$	72	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	8.5	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	44	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	2	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	5	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	300	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	18.51	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$1,796,492	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$17,670	in 2018 dollars
Indirect Annual Costs (IDAC) =	$151,842	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$169,512	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$8,982	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$940	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$5,714	in 2018 dollars
Annual Catalyst Replacement Cost =		$2,033	in 2018 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$17,670	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$1,476	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$150,366	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$151,842	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$169,512	per year in 2018 dollars
NOx Removed =	9	tons/year
Cost Effectiveness =	$18,919	per ton of NOx removed in 2018 dollars