Sunnyside Operations Associates L.P.

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April 9, 2020

Mr. Bryce Bird
Utah Division of Air Quality
195 North 1950 West
Salt Lake City, Utah 84116

RE: Four Factor Analysis - Regional Haze 2nd Implementation Period
Sunnyside Cogeneration Associates, Title V Operating Permit Number #700030004

Dear Mr. Bird:

Attached is the Sunnyside Cogeneration Associates (Sunnyside) four factor analysis to meet the requirements of the U.S. Environmental Protection Agency's (EPA's) Regional Haze (RH) program. Sunnyside's analysis has been developed for review by the Utah Division of Air Quality (UDAQ) and Western Regional Air Partnership (WRAP), to complete its reasonable progress analysis as part of the second implementation period for the RH program.

This analysis has been developed using the four-factors addressed in Section 169A(g)(1) of the Clean Air Act (CAA), EPA's guidance, and the direction provided in UDAQ's letter dated October 21, 2019. Specifically, Sunnyside evaluated the sources generating NO_x and SO_2 for the four factors.

As you are aware, this analysis took longer than anticipated in light of the COVID-19 pandemic currently impacting our nation. In developing this analysis resources and vendor's availibity were limited requiring additional time to prepare a complete report.

If you have any questions regarding this submittal, please feel free to contact me or Rusty Netz at (435-888-4476 Ext. 107.

Thank You,

Gerald Hascall
Agent for
Sunnyside Cogeneration Associates

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Brian Mensinger - Trinity Consultants, Inc.
Plant File

REGIONAL HAZE 2ND IMPLEMENTATION PERIOD FOUR-FACTOR ANALYSIS

Sunnyside Cogeneration Associates > Sunnyside, UT

Sunnyside Cogeneration Facility Four-Factor Analysis

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April 8, 2020

Project 204502.0008

1. EXECUTIVE SUMMARY

Sunnyside Cogeneration Associates (Sunnyside) owns and operates a combustion boiler (EU #1), an emergency diesel engine (EU#5) and an emergency generator (EU#7), at its Cogeneration facility located at #1 Power Plant Road, Sunnyside, UT (The Facility). The boiler features a circulating fluidized bed, a baghouse and a limestone injection system. The facility operates under the jurisdiction of the Utah Department of Air Quality (UDAQ) Title V air operating permit (Permit # 700030004).

The following report represents Sunnyside's response to a request by UDAQ on October 21, 2019 that Sunnyside conduct a four-factor analysis of the plant's emission reduction options for visibility impairing pollutants. Per UDAQ, only sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) need to be considered as visibility-impairing pollutants for this analysis.

The United States Environmental Protection Agency's (U.S. EPA's) guidelines in 40 CFR Part 51.308 are used to evaluate reduction measures for the emission units at the Sunnyside cogeneration facility. In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must consider the following four factors and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A):

1. The costs of compliance
2. The time necessary for compliance
3. The energy and non-air quality environmental impacts of compliance
4. The remaining useful life of any potentially affected sources

The purpose of this report is to provide information to UDAQ and the Western Regional Air Partnership (WRAP) regarding potential SO_2 and NO_X emission reduction measures for the Sunnyside cogeneration facility. Based on the Regional Haze Rule, associated U.S. EPA guidance, and UDAQ's request, Sunnyside understands that UDAQ will only move forward with requiring emission reductions from the Sunnyside Cogeneration Facility if UDAQ determines that the emission reductions are needed to show reasonable progress and provide the most cost-effective controls among all options available. In other words, control reductions should be imposed by the Regional Haze Rule only if these potential measures result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals. Sunnyside is submitting this report to provide results of the four-factor analysis and discuss the feasibility or infeasibility of these potential options. Table 1-1 below summarizes the SO_2 and NO_X emission reduction measures and the evaluation outcome.

Table 1-1. Summary of Findings

Pollutant	Emission Reduction Measure	Technically Feasible?	Cost Effective?	Appropriate for Emissions Reduction?	Notes
SO_2	Spray-Dry Absorbers	No	NA	No	Facility does not own sufficient water rights to implement technology.
	Dry Scrubbing	Yes	No	No	Implementation requires an additional baghouse, combined cost exceeds practical application.
	Wet Scrubbing	No	NA	No	Insufficient water available similar to spray-dry absorber. Therefore, technically infeasible.
	Hydrated Ash Reinjection (HAR)	No	NA	No	Impractical with current CaO levels available in the ash. Increasing ash or limestone feed to sufficient CaO levels is not technically feasible.
NO_X	Selective Catalytic Reduction (SCR)	Yes	No	No	Significant fouling and poisoning of catalyst. Therefore, technically infeasible. Cost also exceeds practical application.
	Selective Non-Catalytic Reduction (SNCR)	Yes	No	No	Insufficient residence time or temperatures to be effective. Cost also exceeds practical application.

As discussed in this four-factor analysis, Sunnyside concludes that the facility's existing control measures are the most suitable for SO_2 and NO_X emissions from the CFB boiler. The emissions reduction methods analyzed in this report are found to be either technically infeasible or cost ineffective. The boiler has existing NO_X emission limits in place based on the Title V permit, which are similar to existing boilers with PSD BACT limits. Likewise, actual SO_2 emissions from the boiler are comparable to PSD BACT limits for boilers that utilize waste (i.e., refuse) coal. As such, add-on NO_X and SO_2 control may provide minimal benefit to visibility.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. In establishing a reasonable progress goal for a Class I area, the state must (40 CFR 51.308(d)(1)(i)):

> *(A) consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.*
>
> *(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction.*[1]

On October 21, 2019, UDAQ sent a letter to Sunnyside requesting "a four-factor analysis of its operations for nitrogen oxide and sulfur dioxide" for Sunnyside's Sunnyside Cogeneration Facility.[2] Sunnyside understands that the information provided in a four-factor review of control options will be used by UDAQ in their evaluation of reasonable progress goals for Utah. Based on the RHR, associated U.S. EPA guidance, and UDAQ's request, Sunnyside understands that UDAQ will only move forward with requiring emission reductions from the Sunnyside cogeneration facility if UDAQ determines that the emission reductions are needed to show reasonable progress and provide the most cost-effective controls among all options available. In other words, control reductions should be imposed by the RHR only if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals. The purpose of this report is to provide information to UDAQ and WRAP regarding SO_2 and NO_X emission reductions that could or could not be achieved for the Sunnyside Cogeneration Facility, if the emission reductions are determined by UDAQ to be necessary to meet the reasonable progress goals.

The information presented in this report considers the following four factors for the emission reductions:

1. Costs of compliance
2. Time necessary for compliance
3. Energy and non-air quality environmental impacts of compliance
4. Remaining useful life of the Emission Units

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[1] 40 CFR 51. 308(d)(1)(i)(B).

[2] Refer to letter from UDAQ to Sunnyside dated October 21, 2019.

The four-factor analysis is satisfied by conducting a stepwise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Factor 4 is also addressed in the stepwise review of the emission reduction options, primarily in the context of the costing of emission reduction options, if any, and whether any capitalization of expenses would be impacted by limited equipment life. Once the stepwise review of reduction options was completed, a review of the timing of the emission reductions is provided to satisfy Factor 2 of the four factors.

A review of the four factors for SO_2 and NO_X can be found in Sections 5 and 6 of this report, respectively. Section 4 of this report includes information on the Sunnyside cogeneration facility's existing/baseline emissions.

In this analysis, various electricity generating technologies were reviewed to identify the technologies capable of burning refuse coal. It was concluded that the only technically feasible and commercially available technology capable of burning refuse coal is a circulating fluidized bed boiler. Pulverized coal (PC) boiler and integrating gasification combined cycle (IGCC) combustion units are not designed to operate with fuel that has a relatively low heating value as in the case for refuse coal. Therefore, these alternative boiler designs were not considered for this project.

3. SOURCE DESCRIPTION

The Sunnyside cogeneration facility is in Sunnyside, Carbon County, Utah (approximately 25 miles southeast of Price). The nearest Class I areas and their respective distance from the facility are Canyonlands National Park (91 miles), Capital Reef National Park (96 miles), Bryce Canyon National Park (171 miles) and Zion National Park (217 miles).

The Sunnyside power plant began operations in May of 1993. The electricity it produces is sold to PacifiCorp, operating as Utah Power and Light (UPLC). The plant qualifies as a small power production facility and qualifying cogeneration facility ("QF") under the Public Utility Regulatory Policy Act of 1997 ("PURPA"). [3] The facility operates a coal-fired combustion boiler that features circulating fluidized bed (CFB), a baghouse and a limestone injection system. The facility also operates an emergency diesel engine and emergency generator. All process units are currently permitted in its UDAQ Title V air operating permit (Permit # 700030004) which was renewed on April 30, 2018. The CFB boiler is subject to the NESHAPS Part 63, Subpart UUUUU Mercury and Air Toxics Standards [MATS] Rule. As a result, Sunnyside is required to meet standard of 0.2 lb/MMBtu of an SO_2.[4] This standard requires continuous monitoring with a continuous emission monitor system (CEMS).

The plant's CFB boiler, designed by Tampella Power, produces steam that drives a Dresser-Rand turbine generator.[5] The CFB boiler and baghouse uses limestone injection. Historically, CFB boilers have been one of the primary low emission combustion technologies for commercial and small utility installations using low grade fuels. This trend continues with CFB technology being considered for smaller coal fired units as a means to effectively utilize lower quality fuels and meet environmental requirements. [6]

The current boiler produces emissions from one stack at Sunnyside's cogeneration facility. For the purposes of a control technology review, only the emissions from the boiler stack itself are considered as well as the operations from the emergency diesel engine and emergency generator.

3.1. PROCESS DESCRIPTION

The following subsections describe the processes and equipment used to generate power at the Sunnyside cogeneration facility. The process addressed in this four-factor analysis can be divided into two emission sources: CFB Boiler operations and emergency generators.

[3] Catalog of CHP Technologies, Section 4. Technology Characterization – Steam Turbines, U.S. EPA Combined Heat and Power Partnership, March 2015

https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_4._technology_characterization_-_steam_turbines.pdf

[4] Federal Register Vol. 81, No.66 Table2 to Subpart UUUUU of Part 63 Emission Limits for Existing EGUs

[5] https://www.aciinc.net/sunnyside

[6] Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units, U.S. EPA Office of Air and Radiation, October 2010

https://www.epa.gov/sites/production/files/2015-12/documents/electricgeneration.pdf

3.1.1. Boiler Operations

The Sunnyside Cogeneration Facility produces steam in a CFB boiler with a design maximum heat input capacity of 700 MMBtu/hr which feeds a steam turbine generator, producing a nominal 58 MW of power.[7] [8] Power produced by the steam generator is sold to the grid. The boiler runs on waste coal from two surrounding sub-bituminous waste-coal piles which are located on land owned or leased by Sunnyside. The waste-coal originates from a coal wash plant that previously removed the ash and sulfur out to the coal, leaving behind waste coal piles. Similar to other waste-coal burning facilities, Sunnyside has the added environmental benefit of utilizing a waste product, cleaning up old mining sites and generating an ash that is used as a beneficial back-fill material for reclamation of the old mining sites.

The CFB unit is equipped with air pollution control system to minimize emissions of air pollutants. Limestone is injected into the CFB with the coal feed stream to provide in-situ control of SO_2. The flue gas from the CFB is directed to a fabric filter baghouse for particulate matter ($PM/PM_{10}/PM_{2.5}$) control.

CFB combustion involves waste-coal and limestone being suspended through the action of primary combustion air distributed below the combustion floor. More specifically, in the CFB boiler, the crushed fuel is mixed with limestone in a highly turbulent, suspended (fluidized) state. The fluidized bed mixing facilitates inherent emission reductions in a number of ways. First, this turbulent mixing enhances the heat transfer efficiency and provides an optimized combustion environment for the use of low-grade fuels such as waste-coal. Second, with combustion temperatures ranging between 1,575 degrees (°) Fahrenheit (F) and 1,650 °F in the CFB coal-fired boiler, the formation of thermal NO_x and, to some extent, SO_3 is reduced, relative to older designs. Meanwhile, a PC boiler has combustion temperatures of 2,500 to 2,800°F and subsequently produces more NO_x.[9] Third, SO_2 leaving the combustion chamber (boiler) is significantly reduced due to the thermo-chemical reaction of the calcium/magnesium sorbent with fuel particles.

In summary, the Sunnyside facility supplies power using a CFB boiler that facilitates power generation with inherently low emissions through the consumption of waste coal that can have other impacts to the water and soil quality in the environment.

3.1.2. Emergency Diesel Engine and Emergency Generator

An emergency diesel engine rated at approximately 201 HP, is used to power the emergency backup fire-pump. A 500-kW emergency generator is on site to provide power to the plant's operations in the event of a power outage. While emissions are minor for the maintenance and testing of emergency generator engines, they have been addressed in this analysis for completeness.

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[7] UDAQ Inspection Report Dated August 9, 2016.

[8] Combined Heat and Power Technology Fact Sheet Series, U.S. Department of Energy, 2016, https://www.energy.gov/sites/prod/files/2017/12/f46/CHP%20Overview-120817_compliant_0.pdf

[9] U.S. EPA Clean Air Technology Center. Alternative Control Techniques Document – NOx Emissions from Utility Boiler. Research Triangle Park, North Carolina. -3-150, EPA-453/R-94-023, March 1997,

4. BASELINE EMISSIONS

This section summarizes emission rates that are used as baseline rates in the four-factor analysis presented in Sections 5 and 6 of this report.

4.1. BASELINE EMISSION RATES

Baseline emission rates in tons per year are needed for both SO_2 and NO_X to complete the four-factor analysis. They are used in the control cost-effectiveness analysis to determine the annual dollars of control cost per ton of pollutant reduced, as well as in the scaling of operating costs for control equipment under consideration.

Sunnyside has provided the following emissions for this four-factor analysis which are based on actual emission rates. The projected annual emissions from the boiler for both NO_X and SO_2 are determined using CEMS data while the emergency generator and emergency diesel engine are based on the manufacturer specifications and past-actual usage. These same baseline rates are provided to UDAQ for use in the on-the-books/on-the-way basis for modeling because no changes to boiler and/or emergency generator operation are expected between now and 2028. The baseline annual emission rates for the purposes of this analysis are summarized in Table 4-1.

Table 4-1. Baseline Emission Rates (tons/yr)

Pollutant	Baseline Annual Emissions (tons/yr)		
	Boiler (EU #1)	Emergency Diesel Engine (EU #5)	Emergency Generator (EU #7)
SO_2	471	0.001	0.020
NO_X	431	0.020	0.310

The values for the CFB boiler are based on the facility's average annual emissions (tons/yr) for NO_X and SO_2 between 2016 and 2018, as recorded by the plant's CEMS. The three-year averaged values represent reasonable expected emissions for the coal-fired boiler, emergency engine, and emergency generator. The emergency generator and emergency diesel engine's emissions are calculated using manufacturer's specifications and yearly operating data, including the amount of diesel used and annual hours of operation. Using the baseline annual emissions, SO_2 and NO_X emissions from the boiler and emergency equipment were reviewed on a lb/MMBTU basis and a lb/HP-hr basis respectively, as shown in Table 4-2 below.

Table 4-2. Baseline Emission Rates

Pollutant	Baseline Annual Emissions		
	Boiler (EU #1)	Emergency Diesel Engine (EU #5)	Emergency Generator (EU #7)
	(lb/MMBTU)	(lb/HP-hr)	(lb/HP-hr)
SO_2	0.17	8.29E-4	2.71E-3
NO_X	0.15	1.66E-2	4.20E-2

When compared to Prevention of Significant Deterioration (PSD) permitting Best Available Control Technology (BACT) limits in the RACT/BACT/LAER Clearinghouse (RBLC) database, the boiler's SO_2 and NO_X emission levels on a lb/MMBTU basis are comparable to PSD BACT limits for CFB boilers that process refuse coal, and are significantly lower than emission limits provided in Sunnyside's Title V permit as shown in Table 4-3.[10]

Table 4-3. Permitted Emission Limits (lbs/MMBtu)

Pollutant	Boiler (EU #1) Emission Limits (lbs/MMBtu)	
	Normal Operations[11]	Startup, Shutdown, Maintenance/Planned Outage, or Malfunction
SO_2 Title V	0.42	1.2
SO_2 MATS	0.2	--
NO_X	0.25	0.60

[10] RBLC Search results are provided in Appendix C.

[11]

5. SO_2 FOUR FACTOR EVALUATION FOR CFB BOILERS

The four-factor analysis is satisfied by conducting a stepwise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key factors determined in Step 4 of the stepwise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is addressed further in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

The baseline SO_2 emission rates that are used in the SO_2 four-factor analysis are summarized in Table 4-2. The basis of the emission rates is provided in Section 4 of this report. The CFB boiler is permitted to achieve a reduction of at least 70% SO_2 that would otherwise be emitted from the combustion process. In practice, Sunnyside the CFB boiler achieves greater than 90% reduction to meet NESHAPS, Subpart UUUUU (MATS Rule) of 0.2 lb/MMBTU of SO_2 for Electric Generating Units (EGUs).[12] More specifically, to control SO_2, the CFB process injects limestone to reduce sulfur compounds in the exhaust, including sulfuric acid (H_2SO_4) and SO_2. Within the combustion zone, calcium oxide (CaO) is formed by in-situ calcinination of the injected limestone. SO_2 formed during the combustion process combines with the in-situ limestone to form calcium sulfite ($CaSO_3$) and/or calcium sulfate ($CaSO_4$), $_{particulate}$, which is collected downstream in the fabric filter.

This CFB boiler configuration is also commonly instituted to achieve BACT for permitted CFB boilers.[13] When compared to the permitted emission rates for SO_2 found in the RBLC database,[14] Sunnyside's CFB boiler emits SO_2 at a rate comparable to CFB boiler installations around the country.

5.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES

SO_2 is generated during fuel combustion in a boiler, as the sulfur in the fuel, specifically the waste-coal, is oxidized by oxygen in the combustion air.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for the Sunnyside CFB boiler are summarized in Table 5-1. Alternate fuels are not considered in this analysis based on the CFB boiler is not designed for other fuels; therefore, it exists as the base case. The retrofit controls predominantly include add-on controls that eliminate SO_2 after it is formed. Sunnyside

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[12] Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs, Low Rank Virgin Coal, SO_2.

[13] Utah Division of Air Quality New Source Plan Review, Sevier Power Company's 270 MW Coal-Fired Power Plant, Dec. 2003

[14] RBLC Search results are located in Appendix C.

currently uses limestone injection to control SO_2 emissions. This top-down control review investigates whether installation of an additional SO_2 control device in series with the prior control technology is warranted.

Table 5-1. Available SO_2 Control Technologies and Measures for the Sunnyside CFB Boiler

SO_2 Control Technologies
Spray Dry Absorbers
Wet Scrubbing
Dry Scrubbing
Hydrated Ash Reinjection

5.1.1. Spray Dry Absorbers

Spray dry absorption involves spraying a high concentration, aqueous slurry sorbent, typically consists of lime, sodium bicarbonate, or trona,[15] into the wet flue gas stream. The sorbent interacts with acid gases (HCl, for example) or SO_2 and forms larger particles, while the evaporation of water from the slurry cools the flue gas stream. The cooling enhances precipitation of these particles from the flue gas stream, and the particles can be subsequently removed using an electrostatic precipitator or dry filter downstream.[16]

Spray dry absorbers require sufficient water to prepare the aqueous alkaline slurry. Water usage can vary greatly as injection rates of slurry and dilution water are controlled by signals from the in-stack CEMS and the stack temperature.[17]

5.1.2. Wet Scrubbing

A wet scrubber is a technology that may be installed downstream of the boiler. In a typical wet scrubber, the flue gas flows upward through a reactor vessel, while an aqueous slurry of alkaline reagent flows down from the top. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to maximize dissolution of SO_2 into the alkaline reagent by distributing the reagent across the scrubber vessel. The calcium (typically) in the aqueous reagent reacts with the SO_2 in the flue gas to form calcium sulfite ($CaSO_3$) and/or calcium sulfate ($CaSO_4$), which collects in the bottom of the reactor and is subsequently removed with the scrubber sludge.

5.1.3. Dry Scrubbing - Dry Sorbent

Dry scrubbers utilize powdered sorbents, such as dry limestone or lime, and pneumatically inject the powder downstream of the boiler. A dry scrubber would be an add-on control technology after the limestone injection already occurring in the CFB boiler. Dry sorbent injection involves a sorbent storage tank, feeding mechanism, transfer line, blower and injection device. An expansion chamber is located downstream of injection point to increase residence time and efficiency. SO_2 in the flue gas reacts directly with the powdered reagent to form waste particles which are subsequently carried in the flue gas through a particulate control device, such as a fabric filter or electrostatic precipitator, where the particles are collected from the cleaned flue gas. Dry

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[15] Trona is a sodium carbonate compound, which is processed into soda ash or baking soda. https://www.wyomingmining.org/minerals/trona/

[16] Rogoff et al., Waste to Energy 2nd Ed., Section 8.2.4.6 Spray dryers/dry scrubbers

[17] Ibid.

scrubbers are usually applied when lower removal efficiencies are required, or for smaller plants.[18] Effects on plant operation vary for the different sorbents. Some coal-fired boiler owners and operators select to use hydrated lime if possible, in order to avoid potential heavy metal leaching from the collected fly ash mixed with DSI by-product.[19]

5.1.4. Dry Scrubbing - Hydrated Ash Reinjection

Hydrated ash reinjection (HAR) effectively reduces SO_2 emissions by increasing the extent of reaction between SO_2 and hydrating sorbents in the CFB. The CFB recycles fly ash in the system for a specified period, after which the flue gas is sent to a particulate control device where the sulfur-rich particulates are collected. Design and efficiencies for HAR systems vary greatly based on vendor and sorbent type.[20] HAR also requires significant amounts of fly ash to maintain reaction rates that sustain desulfurization of the flue gas.

5.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible SO_2 control technologies that are identified as available in Step 1.

5.2.1. Spray Dry Absorbers

Installing an additional spray dry absorber in series with the current FGD system would further reduce SO_2 emissions at Sunnyside's facility. Despite the misleading name, spray dry absorbers (also known as semi-dry absorbers), require water to atomize the reactive sorbent into an aqueous solution.[21] [22]

Sunnyside's operation already requires a significant use of water, and the plant's current water rights are not sufficient enough to sustain the necessary water usage to operate an additional spray dry absorber. In 2018, Sunnyside exceeded their allotted water rights. Consequently, it had to purchase 44.5 million gallons of additional water from the city of East Carbon.[23] At times there is not sufficient water for purchase. The facility already uses the majority of its water rights and normal years for current operations and has to buy additional water to supply the necessary amount of water to the cooling towers. Any additional water consumption would result in the water rights being used much more rapidly and represents an undue burden on the facility to acquire the water for spray dry absorber operation. As additional water rights are not available in the quantity required for implementing water-intensive technology, installation of an additional spray dry absorber in series with Sunnyside's current limestone injection technology is considered infeasible and will not be evaluated further

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[18] See Air Pollution Control Technology Fact Sheet, Flue Gas Desulfurization, EPA-452/F-03-034, Pg. 4

[19] Power Engineering International – Dry sorbent injection for SOx emissions control, June 28, 2017

[20] Montana Department of Environmental Quality, Regional Haze Four Factor Analysis, Rosebud Power Plant, 2019

[21] See Air Pollution Control Technology Fact Sheet, Flue Gas Desulfurization, EPA-452/F-03-034, Pg. 4

[22] See description of spray dry absorber technology available from vendor : https://www.gea.com/en/products/spray-dryer-absorber.jsp

[23] According to email correspondence from Sunnyside Cogeneration on the water usage at the facility in 2018.

5.2.2. Wet Scrubbing

Similar to spray dry absorption, A wet scrubbing system utilizes a ground alkaline agent, such as lime or limestone, in slurry to remove SO_2 from stack gas. However, wet scrubbing uses more water than spray dry systems to generate the aqueous sorbent. The alkaline slurry is sprayed into the absorber tower and reacts with SO_2 in the flue gas to form insoluble $CaSO_3$ and $CaSO_4$ solids. A wet flue gas desulfurization (FGD) must be located downstream of the fabric filter baghouse. The spent slurry is dewatered using settling basins and filtration equipment. Recovered water is typically reused to blend new slurry for the wet scrubber. A significant amount of makeup water is required to produce enough slurry to maintain the scrubber's design removal efficiency. Water losses from the system occur from evaporation into the stack gas, evaporation from settling basins, and retained moisture in scrubber sludge. As the concentration of the SO_2 in the CFB gas is inherently low due to existing control technologies, it is not anticipated that a wet FGD system will provide a significant reduction in overall SO_2 emissions.

As mentioned previously, the plant's current water rights and water availability are not sufficient to operate a wet scrubber instead of limestone injection technology, or in series with the current limestone injection technology. Since any additional water consumption represents an undue burden on the facility to acquire the water for wet scrubber operation, this technology is considered infeasible and will not be evaluated further.

5.2.3. Dry Scrubbing

Dry scrubbing systems are mechanically simple systems and use less water than wet scrubbing and spray dry systems.[24] Due to limited water use and simple waste disposal, dry injection systems install easily and are good candidates for retrofit applications.[25].Therefore, dry scrubbing is considered technically feasible, and considered further.

5.2.4. Hydrated Ash Reinjection

Application of HAR results in higher particulate loading in the flue gas, and subsequently generates larger emissions particulate matter. Flue gas exiting the CFB at Sunnyside typically contains approximately 10% unreacted calcium oxide in the fly ash and even less in the bottom ash. [26] To enable HAR, either additional limestone loading to the CFB would needed or significant amounts of ash to effectively scrub SO_2. Therefore, large amounts of unreacted fly ash are required to implement HAR to be able to handle the additional loading. Additionally, a larger particulate control device would likely be required to handle the increased particulate matter in the flue gas.

HAR implementation would be impractical with 10% available CaO and even if adding reagent would be feasible it would likely require the installation of an enhanced baghouse with the addition of additional particulate in the flue gas of the CFB due to the significant amount of ash reagent that would be required. Due to the questionable technical feasibility of HAR, and the generation of PM emissions, the technology is considered technically infeasible, and no longer considered.

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[24] As limestone is injected into the CFB boiler and calcines in the combustion chamber, the addition of lime as a reagent in a scrubber is practical based on reactivity and temperature for further SO_2 removal in flue gas.

[25] See Air Pollution Control Technology Fact Sheet, Flue Gas Desulfurization, EPA-452/F-03-034, Pg. 4

[26] Based on fly ash characterization results conducted at Sunnyside Cogeneration Associates.

5.3. STEP 3: RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

Step 3 of the top-down control review is to rank the technically feasible options by effectiveness. Table 5-2 below ranks feasible control technologies according to their respective control efficiency for SO_2 removal.

Table 5-2. SO_2 Control Efficiencies for Remaining Feasible Technologies

Control Technologies	Control Efficiency[27] [28]
Dry Scrubbing	50-98%

Control efficiency is undetermined at this time because the most effective method to determine optimal performance and balance of plant effects is to conduct a DSI trial on the unit in question. These trials typically range from one week to three months in duration, using temporary equipment designed for this purpose.[29] For the purposes of evaluation the average of the range was used.

5.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS

Step 4 of the top-down control review is the impact analysis. Sunnyside's average emission rate of SO_2 between 2016 and 2018 was 471 tons per year or approximately 0.17 lbs of SO_2 per MMBTU with the utilization of limestone injection technology.

Installing dry scrubbing technology at Sunnyside also requires the installation of additional baghouse to remove particulates generated from dry scrubbing operation. Sunnyside's cost analysis of this technology shows that dry scrubbing provides an undue economic burden to the facility, costing approximately $10,372 per ton of SO_2 removed.

The boiler currently operated was determined to achieve BACT for SO_2 at the time of the boiler's New Source Review (NSR) permit.[30] It has further reduced its emissions to meet NESHAPS, Part 63 Subpart UUUUU (MATS).[31] When compared to the permitted emission rates for SO_2 found in the RBLC database, Sunnyside's CFB boiler emits SO_2 at a rate comparable to SO_2 BACT limits of CFB boiler installations around the country.[32] The Sunnyside CFB boiler is already equipped with limestone injection, which is currently installed primarily for SO_2 control on the CFB technology. Sunnyside is currently injecting limestone to manage SO_2 emissions as needed to meet the existing, appropriately low SO_2 limits set forth by BACT, NSPS Subpart Da, and NESHAPs Part 63,

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[27] See cost analysis for hydrated ash reinjection performed by Colstrip Energy Limited Partnership's Rosebud Power Plant, for Regional Haze Four-Factor Analysis in 2019, Submitted to Montana DEQ, Bison Engineering.

[28] Ibid.

[29] Power Engineering International – Dry sorbent injection for SOx emissions control, June 28, 2017

[30] See Title V Operating Permit #700030004 Condition II.B.2.c

[31] Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs, Low Rank Virgin Coal, SO_2 require 0.2 lb/MMBtu.

[32] See RBLC Tables provided in Appendix C

Subpart UUUUU (MATS Rule).[33]

Since Sunnyside's emission rate maintains parity with NSPS and MATS emission limitations for similar processes and no technologies are available to reduce the emission rate further. The current process of a limestone injection technology to achieve a reduction in SO_2 emissions is considered BACT for the boiler. Furthermore, this emission rate is well below the established SO_2 limitation from NSPS Subpart Da, which is 0.6 lb/MMBTU and remains below NESHAPS, Part 63 Subpart UUUUU (MATS) of 0.2 lb/MMBTU. No technologies are available to reduce SO_2 emissions further. Therefore, the current process of using inherently low sulfur raw materials and natural scrubbing is considered BACT for the boiler.

5.4.1. Cost of Compliance

The currently installed and operating controls are assumed to be cost-effective. As stated previously, all cost calculations and cost effectiveness determinations are considered on the basis of the currently controlled emission levels. Detailed cost calculations for the SO_2 control technology is included in Appendix A.

5.4.1.1. Dry Scrubber Cost Calculations

Dry Scrubber cost calculations are determined using the U.S. EPA's Control Cost Manual methodology. A retrofit factor of 1.3 is used in determining the capital costs associated with the potential installation of dry scrubber technology.

5.4.1.2. Cost Effectiveness

The cost effectiveness is determined by dividing the annual control cost by the annual tons reduced. Table 5-3 summarizes the results. Based on the results of this analysis, the cost of dry scrubbing is not cost effective.

Table 5-3. SO_2 Cost of Compliance Based on Emissions Reduction

Control Option	Control Cost ($/yr)	Baseline Emission Level (tons)	SO_2 Reduction (%)	Emission Reduction (tons)[34]	Cost Effectiveness ($/ton removed)
Dry Scrubber	$3,253,696	471	74%	319	$10,202

5.4.2. Timing for Compliance

Sunnyside believes that reasonable progress compliant controls are already in place. However, if UDAQ and WRAP determine that one of the SO_2 control options analyzed in this report is necessary to achieve reasonable progress, it is anticipated that this change could be implemented during the period of the second

[33] BACT restricts SO_2 emissions to 0.42 lb/MMBTU, while NSPS Subpart Da restricts SO_2 emissions to 0.6 lb/MMBTU.

[34] Assumes that Sunnyside plant has a 91.5% uptime based on its baseline period. Therefore, emission reduction = baseline emissions * (1 – SO_2 reduction) * Uptime.

long-term strategy for regional haze (approximately ten years following WRAP's reasonable progress determination).

5.4.3. Energy Impacts

The cost of energy required to operate the control devices has been included in the cost analyses found in Appendix A. To operate any of these add-on control devices, overall plant efficiency would decrease due to the operation of the add-on controls. Additionally, this control equipment would consume additional power causing uses all or in excess of its parasitic load and Sunnyside would not meet its power purchase agreement obligation.

Emission reducing options that involve water also require significant energy to operate the wet scrubber and associated equipment (pumps, atomizers, etc.). However, water-intensive control technologies have been eliminated due to a lack of water availability.

The use of emissions reduction options involving the injection of lime for dry scrubbing and wet scrubbing also causes significant energy impacts. The production of lime is an energy-intensive process that can result in increases in NO_X, particulate matter, and SO_2 emissions, an effect directly counters to regional haze efforts. This lime production emissions increase would then be coupled with the energy and emissions impacts resulting from the transportation of the lime to the facility. The production and delivery of lime to the Sunnyside facility would require significant energy and would result in emission increases of pollutants that directly contribute to visibility impairment around the country.

5.4.4. Non-Air Quality Environmental Impacts

Technically feasible add-on SO_2 control options that have been considered in this analysis also have additional non-air quality impacts associated with them.

- A dry scrubbing control system will require additional particulate loading in the flue gas thereby increasing the volume to be handled, which will put a burden on the existing baghouse system and result a larger baghouse control system to capture PM emissions exiting from the stack.

5.4.5. Remaining Useful Life

The remaining useful life of the boiler will likely impact the annualized cost of an add-on control technology (dry scrubbing control) because the useful life is anticipated to be less than the capital cost recovery period of 20 years or less. Although, the cost analysis presented in this report is based on 20 years to be conservative.

5.5. SO_2 Conclusion

The CFB boiler, equipped with limestone injection, inherently removes the vast majority of SO_2 that is created from the process. [35] The limestone injection configuration, as currently used was determined to achieve BACT and MATS emission limitations. Furthermore, Sunnyside's current SO_2 control technology is commonly used to achieve BACT for CFB boilers.[36]

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[35] See Sunnyside's Title V Operating Permit, 700030004, Condition II.B.2.f

[36] BACT determinations provided in RBLC Search Results, Appendix C.

This analysis did not identify any technically feasible and cost-effective control options to reduce SO_2 beyond the low levels currently achieved by control options already permitted for the boiler.

6. NO_X FOUR FACTOR EVALUATION FOR CFB BOILERS

As described in Section 2, the Factors of the four-factor analyses are considered by conducting a stepwise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key impacts determined in Step 4 of the stepwise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is primarily addressed in in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

The baseline NO_X emission rates that are used in the NO_X four-factor analysis are summarized in Table 4-3. The basis of the emission rates is provided in Section 4 of this report. The boiler currently has CFB technology installed. The baseline NO_X emission rates for the Sunnyside CFB boiler are within the range of permitted Title V values on a lb/MMBtu basis.

6.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

NO_X emissions are produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions from the combustion of fuel. Thermal NO_X emissions are produced through high-temperature oxidation of nitrogen found in the combustion air. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel. Many variables can affect the equilibrium in the boiler, which in turn affects the creation of NO_X.[37]

A circulating fluidized bed reduces the fuel required to achieve sufficient material temperatures, over traditional FBC units, limiting thermal NO_X production in the EGU's system. A CFB boiler uses staged combustion limiting the formation of NO_X.[38] This effect is combined with the benefits of combusting the fuel in stages, a method which allows for more fuel to be burned at a lower temperature rather than the higher peak flame temperature within the boiler, thereby reducing thermal NO_X formation.

Step 1 of the top-down control review is to identify available retrofit control options for NO_X. The available NO_X retrofit control technologies for the Sunnyside Boiler are summarized in Table 6-1.

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[37] C. B. Oland, Guide to Low-Emission Boiler and Combustion Equipment Selection, Oak Ridge National Laboratory, April 2002

[38] Technology Overview: Circulating Fluidized Bed Combustion, U.S. EPA Office of Air Quality Planning and Standards, June 1982

Table 6-1. Available NO_X Control Technologies for the Sunnyside Boiler

NO_x Control Technologies	
Combustion Controls	Circulating Fluidized Bed (CFB) (Base Case)
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

NO_X emissions controls, as listed in Table 6-1, can be categorized as combustion or post-combustion controls. Combustion controls reduce the peak flame temperature, which minimizes NO_X formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) convert NO_X in the flue gas to molecular nitrogen and water.

6.1.1. Combustion Controls

6.1.1.1. Circulating Fluidized Bed

Circulating fluidized bed (CFB) combustion is a specific type of fluidized bed combustion (FBC). To begin, FBC combustion involves coal being crushed into fine particles then suspended in a fluidized bed by upward-blowing jets of air. This results in a turbulent mixing of combustion air with the coal particles. The coal is mixed with a sorbent, specifically limestone (for SO_2 emission control). The operating temperatures for FBC are in the range of 1,500°F to 1,670°F.

The CFB technology allows for operating at higher gas stream velocities and with finer-bed size particles. There is no defined bed surface but rather high-volume, hot cyclone separators to recirculate entrained solid particles in flue gas to maintain the bed and achieve high combustion efficiency. As noted, before, the lower peak combustion temperature reduces thermal NO_X while the staged combustion reduces fuel NO_X. Sunnyside meets their Title V permitted NO_X emission limits using the CFB technology. Therefore, the CFB technology will not be evaluated further.

6.1.2. Post Combustion Controls

6.1.2.1. Selective Catalytic Reduction

An SCR system is a process whereby NOx is reduced by spraying a reagent, such as urea or ammonia over a catalyst in the presence of oxygen. On the catalyst surface, NH_3 and nitric oxide (NO) or nitrogen dioxide (NO_2) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

When operated within the optimum temperature range of 480°F to 800°F, the reaction can result in removal efficiencies between 70 and 90 percent.[39] The rate of NO_X removal increases with temperature up to a maximum removal rate at a temperature between 700°F and 750°F. As the temperature increases above the optimum temperature, the NO_X removal efficiency begins to decrease. SCR has been successfully installed and operated on many industrial boilers in the U.S. and therefore will be further evaluated.

6.1.2.2. Selective Non-Catalytic Reduction

In SNCR systems, a reagent is injected into the flue gas within an appropriate temperature window. The NO_X and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three to four times as much reagent as SCR systems to achieve similar NO_X reductions.

Like SCR, SNCR uses ammonia or a solution of urea to reduce NO_X through a similar chemical reaction.

$$2NO+4NH_3+2O_2 \rightarrow 3N_2+6H_2O$$

SNCR residence time can vary between 0.001 seconds and 10 seconds.[40] However, increasing the residence time available for mass transfer and chemical reactions at the proper temperature generally increases the NO_X removal. There is a gain in performance for residence times greater than 0.5 seconds. The U.S. EPA Control Cost Manual indicates that SNCR requires a higher temperature range than SCR of between approximately 1,600°F and 2,000°F,[41] due to the lack of a catalyst to lower the activation energies of the reactions; however, the control efficiencies achieved by SNCR vary across that range of temperatures. At higher temperatures, NO_X reduction rates decrease.[42] In addition, a greater residence time is required for lower temperatures.

There are several complications that can occur when attempting to identify and successfully implement the necessary controls to obtain ideal temperature zones for NO_X reduction, resulting in significant variability among the reduction efficiencies achieved with SNCR in boilers .[43] In other words, SNCR in boilers have achieved varying and sometimes poor success, often due to the flue gas temperatures as well as varying combustion loads diverging from optimal values.

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[39] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Pages 2-9 and 2-10.

[40] Air Pollution Control Cost Manual, Section 4, Chapter 1, Selective Non-Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Page 1-8

[41] Ibid, Page 1-6

[42] Ibid, Page 1-14.

[43] Ibid, Page 1-15.

6.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible NO_X control technologies that are identified in Step 1.

6.2.1. Post Combustion Controls

6.2.1.1. Selective Catalytic Reduction

The SCR process requires a reactor vessel, a catalyst, and an ammonia storage and injection system. The presence of the catalyst effectively reduces the ideal reaction temperature for NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NO_X into molecular nitrogen (N_2) and water vapor (H_2O).[44] The optimum operating temperature is dependent on the type of catalyst and the flue gas composition. Generally, the optimum temperature ranges from 480°F to 800°F.[45] The effectiveness of an SCR system is dependent of a variety of factors, including the inlet NO_x concentration, the exhaust temperature, and ammonia injection rate, the type of catalysts poisons, such as particulate matter and SO_2. In practice, SCR systems can operate at efficiencies in the range of 70% to 90%.[46] While SCR has been used for NOx control in pulverized coal applications, the nature of CFB makes it very impractical. Considering the high particulate loading rate and calcium oxide (CaO) concentration of the flue gas due to limestone injection in this section of the CFB boiler exhaust stream, and due to use of refuse coal fuel in the boiler with ash content as high as 60%, an SCR system installed upstream of particulate controls would experience rapid catalyst de-activation and fouling. These technical problems would make the operation of an SCR in the high-dust laden flue gas upstream of the particulate controls technically infeasible for a CFB boiler design.

Since low-temperature SCR is not technically feasible, another option would be to reheat the flue gas downstream of the baghouse to the temperature range known to be effective for SCR use at (650-750°F). This increase in exhaust temperature would require an additional combustion device, also increasing NO_X, SO_2, and $PM_{2.5}$ emissions.

The main drawback with SCR is the overall costs associated with running the system. SCR systems traditionally have high capital and operating costs as large volumes of catalyst required for the reduction reaction as well as replacement catalyst and ammonia reagent costs. Even with the increase in ammonia, $PM_{2.5}$, and SO_2 emissions, Sunnyside has considered this technology to be technically feasible for the CFB boiler and further evaluated the economic feasibility of this technology as detailed in Step 4.

6.2.1.2. Selective Non-Catalytic Reduction

Successful implementation of SNCR poses several technical challenges - most related to maintaining NH_3 injection within the optimal temperature range (approximately 1,600°F and 2,000°F).[47]

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[44] Ibid.

[45] OAQPS, *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/424/B-02-001 (http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf); January 2002

[46] OAQPS, *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/424/B-02-001 (http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf); January 2002

[47] Air Pollution Control Cost Manual, Section 4, Chapter 1, Selective Non-Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Pages 1-5.

Temperature, residence time, reagent injection rate, reagent distribution in the flue gas, uncontrolled NOx level, and CO and O_2 concentrations are important in determining the effectiveness of SNCR. In general, if NOx and reagent are in contact at the proper temperature for a long enough time, then SNCR will be successful at reducing the NOx level. SNCR is most effective within a specified temperature range or window (approximately 1,600°F and 2,000°F) At temperatures below the window, reaction kinetics are extremely slow, such that little or no NO_x reduction occurs. As the temperature within the window increases, the NO_x removal efficiency increases because reaction rates increase with temperature. However, the gain in performance for residence times greater than 0.5 seconds is generally minimal. NO_x generation is minimized between 1,600°F and 2,000°F because the reaction rate plateaus in this range.[48]

Sunnyside's temperatures in the combustor are approximately 1,620 °F and cyclone outlet at 1,670 °F. Plants of similar design have installed lances to inject ammonia at the exit of the cyclone. Within 100 ft of the potential lance injection location, would be the equivalent to 0.2 seconds of residence time, the temperature drops 600 °F; therefore, falling out of the SCNR temperature window. As a result, it is believed that the control efficiency at Sunnyside would be extremely low to the point where the controls would not be effective.

Additionally, at lower temperatures the reaction rate is slowed down, causing ammonia slip, which would result in the formation of ammonia salts, which themselves are condensable $PM_{2.5}$, a visibility impairing pollutant.

Despite the technical and adverse environmental impacts detailed above, the installation of SNCR is considered technically feasible for Sunnyside Cogeneration's boiler and will be considered further.

6.3. STEP 3: RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS

Step 3 of the top-down control review is to rank the technically feasible options to effectiveness. Table 6-2 presents potential NO_X control technologies for the boiler and their associated control efficiencies.

Table 6-2. Ranking of NO_X Control Technologies by Effectiveness

Pollutant	Control Technology	Potential Control Efficiency (%)
NO_X	SCR	70-90
	SNCR	Varies Significantly

[a] Control efficiency for SNCR, per the U.S. EPA Control Cost Manual Chapter 1 Figures 1.3 and 1.4 document SNCR effects from temperature and residence time.

[48] See EPA 452/B-02-001 Chapter 1 Section 4: NO_X Controls, Figure 1.3

6.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

6.4.1. Cost of Compliance

The currently installed and operating controls are assumed to be cost-effective. As stated previously, all cost calculations and cost effectiveness determinations are considered on the basis of the currently controlled emission levels. Detailed cost calculations for each of the NO_X control technologies are included in Appendix B.

6.4.1.1. SNCR Cost Calculations

SNCR cost calculations are determined using the U.S. EPA's Control Cost Manual methodology. A retrofit factor of 1 is used in determining the capital costs associated with the potential installation of SNCR.

6.4.1.2. Cost Effectiveness

The cost effectiveness is determined by dividing the annual control cost by the annual tons reduced. Table 6-3 summarizes the results.

Table 6-3. NO_X Cost of Compliance Based on Emissions Reduction

Control Option	Control Cost ($/yr)	Baseline Emission Level (tons)	NO_X Reduction (%)[49]	Emission Reduction (tons)[50]	Cost Effectiveness ($/ton removed)
SCR	$5,199,098	432	90%	356	$12,039
SNCR	$678,005	432	15%[b]	59	$10,542

[a] Emission reduction assumes actual operating time of Sunnyside at 334 days per year.
[b] NOx reduction is based on evaluation of Figures 1.3 and 1.4 documenting NOx reduction percent control curves based on temperature and residence time in CFB boilers of similar design to Sunnyside.

6.4.2. Timing for Compliance

Sunnyside believes that reasonable progress compliant controls are already in place. However, if the UDAQ determines that one of the control methods analyzed in this report is necessary to achieve reasonable

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[49] EPA's Cost Control Manual, EPA/452/B-02-001, Section 4.2 NOx Post Combustion Chapter 1 SNCR

[50] Assumes that Sunnyside plant has a 91.5% uptime based on its baseline period. Therefore, emission reduction = baseline emissions * (1 – NO_x reduction) * Uptime.

progress, it is anticipated that this change could be implemented during the period of the second long-term strategy for regional haze (approximately ten years following the reasonable progress determination for this second planning period).

6.4.3. Energy Impacts and Non-Air Quality Impacts

As with the addition of SO_2 controls, the introduction of either SNCR or SCR for NO_X control will result in an increase in the electricity demand and/or waste generated at the facility. Overall plant efficiency will decrease as a result of the use of this equipment. Additionally, this control equipment would consume additional power causing uses all or in excess of its parasitic load and Sunnyside would not meet its power purchase agreement obligation.

Environmental agencies around the country have acknowledged the significance of ammonia slip and the potential increases in condensable $PM_{2.5}$ that can result from the introduction of excess ammonia slip into the atmosphere.

For jurisdictions that struggle with meeting PM standards, the California Environmental Protection Agency Air Resources Board's guidance document[51] advises all air quality districts in California to not permit higher levels of ammonia slip:

> *"Air districts should consider the impact of ammonia slip on meeting and maintaining PM_{10} and $PM_{2.5}$ standards, particularly in regions where ammonia is the limiting factor in secondary particulate matter formation. Where a significant impact is identified, air districts could revise their respective New Source Review rules to regulate ammonia as a precursor to both PM_{10} and $PM_{2.5}$."*

The use of SNCR or SCR for NO_X control introduces the risk of excessive ammonia slip emissions, which contributes to visibility impairing compound formation of ammonia salts.

Additionally, there are safety concerns associated with the transport and storage of ammonia, including potential ammonia spills that can have serious adverse environmental and health impacts.

6.4.4. Remaining Useful Life

The remaining useful life of the boiler will likely impact the annualized cost of an add-on control technology SCR and SNCR) because the useful life is anticipated to be less than the capital cost recovery period of 20 years or less. Although, the cost analysis presented in this report is based on 20 years to be conservative.

6.5. NO_X CONCLUSION

The facility currently uses CFB technology to lower NO_X emissions and achieves Title V permitting NO_X limits as currently operated. SCR is a technically feasible control option for this boiler but is not cost effective as costing greater than $10,000 per ton of NO_X removed. While SNCR *may* represent a cost-effective option for NO_X

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[51] California Environmental Agency Air Resources Board's Report to the Legislature: Gas-Fired Power Plant NO_X Emission Controls and Related Environmental Impacts, May 2004. Page 29. https://ww3.arb.ca.gov/research/apr/reports/l2069.pdf

emissions reduction, the introduction of substantial ammonia slip has the potential to cause adverse environmental impacts. The ammonia and $PM_{2.5}$ emissions have the potential to cause direct health impacts for those in the area, and present additional safety concerns for the storage and transportation of ammonia. Despite not having SNCR or SCR installed, the Sunnyside boiler is achieving a NO_X emission rate on a lb/MMBtu basis that is comparable to PSD BACT levels set on CFB boilers.[52] Therefore, additional add-on controls for NO_X emissions reductions are not necessary on the Sunnyside CFB boiler.

[52] See RBLC search results in Appendix C.

7. SO_2 AND NO_X FOUR FACTOR EVAULATION FOR EMERGENCY GENERATOR

Sunnyside cogeneration facility has an emergency generator installed in the event of a loss of power or similar event requiring the plant and facility to maintain electric power. The emergency generator is powered by a 201 HP diesel engine. The emergency diesel engine operates in accordance with the standards set forth in 40 CFR Subpart ZZZZ, the NESHAP for Reciprocating Internal Combustion Engines (RICE) Maximum Available Control Technology (MACT) and is in adherence with the provisions set forth in its UDAQ Title V Permit. The 5000 Kw Emergency generator is subject to NSPS Subpart JJJJ.

Provisions include limiting operation to emergency procedures, emergency demand response, testing and maintenance, and operations in non-emergency settings to 50 hours per year. The emergency engine also follows best combustion practices which include changing the oil and filter after every 500 hours of operation or annually, inspect the air cleaner after every 1,000 hours of operation or annually, and inspect all hoses and belts every 500 hours of operation or annually. These will apply to whichever time provision comes first, either the hours of operation or annual mark. Sunnyside will also limit the engine's time spent at idle and minimize the engine's startup time to under 30 minutes in order to achieve appropriate and safe loading of the engine.

As noted in Table 4-1, the annual SO_2 and NO_X emissions for the emergency engine and generator are quite low and attribute to less than 1% of the Boiler's emissions. Any controls implemented to reduce the current emissions from the emergency generator and engine would result in insignificant emission reductions and only increase the financial burden for Sunnyside. Any emission reductions from the emergency engine and generator would have no statistically significant effect on the Regional Haze to the applicable Class 1 areas stated in Section 3. Sunnyside already follows the standards set forth in 40 CFR Subpart ZZZZ and its UDAQ Title V permit and will continue to follow best combustion practices in order to maintain low emissions.

APPENDIX A : SO_2 CONTROL COST CALCULATIONS

Sunnyside Cogeneration Associates
Four Factor Analysis - Dry Scrubber Cost Analysis

Dry Scrubber Cost Analysis
Table A-1: Dry Sorbent Injection Process Inputs

Variable		Value	Units
Baseline SO_2 Emissions		471	tons/year
SO_2 Removal Efficiency		74%	
Total SO_2 Removed		318.9141	tons/year
Lime Injection Rate		500	lb/hr
Annual Operating Time		8031	hours/year

[1] Assumes control technology uptime of 92% for maintenance and unexpected boiler and control technology downtime.

Table A-2: Dry Sorbent Injection Costs

Cost Item	Factor	Cost	Notes
Captial Costs[1]			
Equipment Cost	A	$2,900,000.00	Dry sorbent injection systems can cost between 40 and 50 USD per kW.
Instrumentation	0.1×A	$290,000.00	Per EPA Control Cost Manual
Sales Tax	0.03×A	$87,000.00	Per EPA Control Cost Manual
Freight	0.05×A	$145,000.00	Per EPA Control Cost Manual
Purchased equipment cost, PEC	B = 1.18×A	$3,422,000.00	Per EPA Control Cost Manual
Direct Installation Costs			
Foundation and Supports	0.12×B	$410,640.00	Per EPA Control Cost Manual
Handling and Erection	0.40×B	$1,368,800.00	Per EPA Control Cost Manual
Electrical	0.01×B	$34,220.00	Per EPA Control Cost Manual
Piping	0.3×B	$1,026,600.00	Per EPA Control Cost Manual
Installation for ductwork	0.01×B	$34,220.00	Per EPA Control Cost Manual
Painting	0.01×B	$34,220.00	Per EPA Control Cost Manual
Direct Installation Cost	0.85×B	$2,908,700.00	Per EPA Control Cost Manual
Retrofit Factor	1.3		
Direct Installation Costs Including Retrofit Factor		$3,781,310.00	
Site Preparation			As required, estimate
Buildings			As required, estimate
Total Direct Cost	1.30×B + SP + Bldg + Direct Costs	$7,203,310.00	Direct costs include foundation, handling, electrical, piping, ductwork, and painting
Indirect Costs (Installation)			
Engineering	0.10×B	$342,200.00	Per EPA Control Cost Manual
Construction and Field Expenses	0.10×B	$342,200.00	Per EPA Control Cost Manual
Contractor Fees	0.10×B	$342,200.00	Per EPA Control Cost Manual
Start-up	0.01×B	$34,220.00	Per EPA Control Cost Manual
Performance Test	0.01×B	$34,220.00	Per EPA Control Cost Manual
Contingencies	0.03×B	$102,660.00	Per EPA Control Cost Manual
Total Indirect Cost, IC	0.35×B	$1,197,700.00	Per EPA Control Cost Manual
Total Capital Investment (TCI)	TCI = DC + IC	$8,401,010.00	

Sunnyside Cogeneration Associates
Four Factor Analysis - Dry Scrubber Cost Analysis

Table A-3: Continued

Cost Item	Factor	Cost	Notes
Direct Annual Costs[1]			
Operating Labor			
Operator		$22,310.63	0.5 hr/shift, 3 shifts/day, 365 d/yr, $40.75/hr
Supervisor		$3,346.59	15% of Operator
Operating Materials			
SOx to be controlled (tpy)		471	Based on average annual SO_2 emissions from 2016 to 2018
Ratio of sorbent to Sox		3	Per Air Pollution Engineering Manual, 2nd Edition, p264
Lime required (tpy)		1413	Lime required (tpy) = SO_2 emissions (tpy) × 3
Limestone Cost ($/ton)		55.81	Current costs from Sunnyside's Limestone supplier
Limestone Cost ($/yr)		$78,859.53	Annual Cost ($/yr) = Limestone Cost ($/ton) × Annual Lime Required
Maintenance			
Maintenance Labor		$22,310.63	0.5 hr/shift, 3 shifts/day, 365 d/yr, $40.75/hr
Maintenance Materials		$22,310.63	100% of Maintenance Labor
Utilities			
Power Consumption		0.67% (% of electrical generation)	Chapter 5 Emission Control Technologies - EPA Base Case v5.13 Table 5-17 Illustrative DSI Cost for Representative sizes and heat rates. 1.7lb/MMBtu (uncontrolled Sunnyside)*2.0 lb/MMBtu (Base case v5.13) = 0.85 Table 5-17 Capacity Penalty%= 0.79%*.85=.67%
Rate		74.68 ($/MWh)	Current revenue from Sunnyide
Electricity	›7% of Electrical Generati	$232,861.68	Cost conservatively represents lost revenue from electricity that could be sold to the grid, and does not include operating costs of boiler
Direct Annual Cost		$381,999.68	
Indirect Annual Costs, IC			
Overhead	60% sum of operating labor, maintenance labor, and associated materials	$42,167.08	
Administrative Charges	2% of TCI	$168,020.20	Where TCI is estimated as $8,401,010.00
Property Taxes	1% of TCI	$84,010.10	Where TCI is estimated as $8,401,010.00
Insurance	1% of TCI	$84,010.10	Where TCI is estimated as $8,401,010.00
Indirect Annual Cost		$378,207.48	Sum of overhead, administrative, taxes, and insurance
Capital Recovery2		$0.09	$ Annually/$ Capital Cost
Annualized Capital Cost		$792,995.91	Capital Recovery * Total Capital Investment
Total Annual Cost (Dry Scrubber)		$1,553,203.07	$/year
Total Annual Cost From Baghouse(s)		$1,700,493.62	$/year
Total Annual Cost From Dry Scrubber and Baghouse(s)		$3,253,696.69	$/year
Cost Effectiveness		$10,202.42	$/ton

[1] Capital recovery calculated based on the methodology provided in the EPA Control Cost Manual, Section 1 Chapter 2, Equation 2.8 and 2.8a on Page 2-22, where an interest rate of 7% is assumed.

Interest	7.00%
Equipment Life	20

Sunnyside Cogeneration Associates
Four Factor Analysis - Dry Scrubber Cost Analysis

Table A-4: Baghouse Operating Parameters

Parameter	Value	Unit
Stack Flowrate	311,000	ACFM
Stack flowrate	165,243	dscfm
Operating Hours	8,031	hr/yr
Pressure Drop	7.5	in. of H_2O

Table A-5: Electricity Costs

Parameter	Value	Unit	Notes
Power Required	1,801,488.52	kWh/yr	Power (kWh/yr = 0.000181(Q)(delta P)(hours per year), per EPA Cost Control Manual Eq 1.14
Energy Cost	0.07468	$/Kwh	
Cost of Electricity	$134,535.16		
Compressed Air Costs			
Flow needed (2scfm/1,000 acfm)	2		Per EPA Cost Control Manual, 1.5.1.8 Compressed Air
Cost (per 1,000 scfm)	$0.38	$/1,000 scfm	Per EPA Cost Control Manual, 1.5.1.8 Compressed Air, where inflation is accounted for using 2019 CEPCI of 602.9, and 2002 CEPCI of 395.6
Cost per min	$0.19	$/min	2 scfm/1,000acfm*(Q)*cost per 1,000 scfm
Cost per hour	$11.43	$/hr	2 scfm/1,000acfm*(Q)*cost per 1,000 scfm * 60 min/hr
Cost per year	$91,795	$/yr	2 scfm/1,000acfm*(Q)*cost per 1,000 scfm * 60 min/hr * 8031 hr/yr, per EPA Cost Control Manual
Cost of Bags	$273,318	$	Scaled on estimates used at Colstrip Energy Limited Partnership's Rosebud Power Plant, and scaled for inflation.

Table A-6: Baghouse Costs

Cost Component	Factor	Cost	Notes
Direct Costs			
Purchased Equipment Costs			
Baghouses Needed		1	
Capital Cost per SCFM:		16	$/SCFM
SCFM		165243	SCFM, engineering estimate
Cost per Baghouse (estimate)		$3,065,044	Scaled on estimates used at Colstrip Energy Limited Partnership's Rosebud Power Plant, and scaled for inflation.
Total Equipment Costs	A	$3,065,044	Per EPA Control Cost Manual
Instrumentation	0.1A	$306,504	Per EPA Control Cost Manual
Equipment Tax:	0.03A	$91,951	Per EPA Control Cost Manual
Freight	0.05A	$153,252	Per EPA Control Cost Manual
Purchased Equpment Cost (PEC)	B = 1.18 × A	$3,616,752	
Direct Installation Costs			
Foundation and Supports	0.04×B	$144,670	Per EPA Control Cost Manual
Handling and Erection	0.5×B	$1,808,376	Per EPA Control Cost Manual
Electrical	0.08×B	$289,340	Per EPA Control Cost Manual
Piping	0.01×B	$36,168	Per EPA Control Cost Manual
Insulation for Ductwork	0.07×B	$253,173	Per EPA Control Cost Manual
Painting	0.04×B	$144,670	Per EPA Control Cost Manual
Direct Installation Costs	0.74×B	$2,676,396	
Retrofit Factor	1.3		
Direct Installation Costs Including Retrofit Factor		$3,479,315	
Site Preparation		Not Included	
Facilities and Building		Not Included	
Total Direct Costs	1.74B + Retrofit	$7,096,067	
Indirect Costs			
Engineering	0.1×B	$361,675	Per EPA Control Cost Manual
Construction and Field Expenses	0.2×B	$723,350	Per EPA Control Cost Manual
Contractor Fees	0.1×B	$361,675	Per EPA Control Cost Manual
Start-up	0.01×B	$36,168	Per EPA Control Cost Manual
Performance Test	0.01×B	$36,168	Per EPA Control Cost Manual
Contingencies	0.03×B	$108,503	Per EPA Control Cost Manual
Total Indirect Costs	0.45×B	$1,627,538	Per EPA Control Cost Manual
Total Capital Investment	2.19×B + Retrofit	$8,723,605	

Sunnyside Cogeneration Associates
Four Factor Analysis - Dry Scrubber Cost Analysis

Table A-7: Continued

Cost Component	Factor	Cost	Notes
Direct Annual Costs			
Operating Labor			
Operator		$89,243	2hr/shift, 3 shifts/day, 365 days/yr, at $40.75/hr
Supervisor		$13,386	15% of operator
Operating Materials			
Maintenance Labor		$44,621	1hr/shift, 3 shifts/day, 365 days/yr, at $40.75/hr
Maintenance Materials		$44,621	100% of Maintenance Labor
Replacement Bags		$109,901	0.4021*cost of bags (accounts for future worth at 3 years and 10%)
Utilities			
Electricity		$134,535	Power (kWh/yr) = 0.000181(Q) (delta P)(hours per year), per EPA Cost Control Manual Eq 1.14
		$91,795	2 scfm/1,000acfm*(Q)*cost per 1,000 scfm * 60 min/hr * 8031 hr/yr, per EPA Cost Control Manual
Compressed Air			
Total Direct Annual Costs		$528,103	
Indirect Annual Costs			
Overhead	Operating Labor	$115,123	Does not include replacement bags
Administrative Charges	2% of TCI	$174,472	Where the TCI is estimated as $8,723,605.15
Property Tax	1% of TCI	$87,236	Where the TCI is estimated as $8,723,605.15
Insurance	1% of TCI	$87,236	Where the TCI is estimated as $8,723,605.15
Capital Recovery	$0.09		assumes 7% interest for 20 years
Total Indirect Annual Costs		$348,944	
Annualized Capital Cost		$823,447	
Total Annual Cost		$1,700,494	

Equipment cost obtained based on a vendor quote used by Bison engineering for cost analysis at Colstrip Energy Limited Partnership's Rosebud Power Plant in Colstrip Montana. Costs related to the construction and implementation of the equipment are obtained from the EPA control cost manual.

Capital recovery calculated based on the methodology provided in the EPA Control Cost Manual, Section 1 Chapter 2, Equation 2.8 and 2.8a on Page 2-22, where an interest rate of 7% is assumed.

Interest	7%
Equipment life	20

APPENDIX B : NO_X CONTROL COST CALCULATIONS

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the *Data Inputs* tab and click on the *Reset Form* button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the *SCR Design Parameters* tab to see the calculated design parameters and the *Cost Estimate* tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

What type of fuel does the unit burn?

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

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. 1.30

* NOTE: You must document why a retrofit factor of 1.3 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	700.00 MMBtu/hour
What is the higher heating value (HHV) of the fuel?	7,072 Btu/lb
What is the estimated actual annual fuel consumption?	883,413,174 lbs/Year
Enter the net plant heat input rate (NPHR)	12 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	6497 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned:

Enter the sulfur content (%S) = 0.71 percent by weight

[redacted]

Coal Type	[redacted]
Bituminous	
Sub-Bituminous	
Lignite	

[redacted]

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})	334	days
Number of days the boiler operates (t_{plant})	334	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.15	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.015	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.05	

*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)	UNK	Cubic feet
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*

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

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516.00	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

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7 2016 CEPCI
Annual Interest Rate (I)	4.75	Percent	
Reagent ($Cost_{reag}$)	2.500	$/gallon for 29% ammonia	
Electricity ($Cost_{elect}$)	0.0821	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	
Operator Labor Rate	40.75	$/hour (including benefits)	
Operator Hours/Day	4.00	hours/day*	

CEPCI = Chemical Engineering Plant Cost Index

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* 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)	$2 50/gallon of 29% Ammonia	U.S Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals usgs gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro pdf	Site specific information. Used average cost of ammonia supplier costs
Electricity Cost ($/kWh)	-	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	https://www.eia.gov/electricity/state/utah/
Percent sulfur content for Coal (% weight)	0 41	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/.	Site Specific
Higher Heating Value (HHV) (Btu/lb)	8,826	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/.	Site specific
Catalyst Cost ($/cubic foot)	227	U.S Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018 Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60 00	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.	Site specific
Interest Rate (Percent)	5.5	Default bank prime rate	https://www.federalreserve.gov/releases/h15/

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 =	700	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	867,081,448	lbs/Year
Actual Annual fuel consumption (Mactual) =		883,413,174	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.20	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.019	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8925	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	90.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	96.77	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	431.85	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.13	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	345,691	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	117.77	/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)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.27	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.6	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.30	

* 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 = $H_{catalyst}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3180	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})	2,934.86	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	360	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 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 x $A_{catalyst}$	414	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	20.3	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	52	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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	38	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/Csol$ =	130	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	17	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	5,900	gallons (storage needed to store a 14 day reagent supply rounded to th

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	0.0786

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	432.96	kW

Cost Estimate

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}) =	$30,630,645	in 2019 dollars
Reagent Preparation Cost (RPC) =	$2,578,991	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$5,954,920	in 2019 dollars
Total Capital Investment (TCI) =	$50,913,923.07	in 2019 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}) =	$30,630,645	in 2019 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) =	$2,578,991	in 2019 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 2019 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:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

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}) =	$5,954,920	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,192,542 in 2019 dollars
Indirect Annual Costs (IDAC) =	$4,006,522 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$5,199,064 in 2019 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 =	$254,570 in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$386,548 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$317,246 in 2019 dollars
Annual Catalyst Replacement Cost =		$234,177 in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2 selected.
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3	
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3	
Direct Annual Cost =		$1,192,542 in 2019 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) =	$4,688 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$4,001,834 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$4,006,522 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$5,199,064 per year in 2019 dollars
NOx Removed =	432 tons/year
Cost Effectiveness =	$12,039 per ton of NOx removed in 2019 dollars

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

What type of fuel does the unit burn?

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

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. 1.30

* NOTE: You must document why a retrofit factor of 1.3 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 700.00 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 7,072 Btu/lb

What is the estimated actual annual fuel consumption? 883,413,174 lbs/Year

Is the boiler a fluid-bed boiler?

Enter the net plant heat input rate (NPHR) 12 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

Provide the following information for coal-fired boilers:

Type of coal burned:

Enter the sulfur content (%S) = 0.71 percent by weight

or

Select the appropriate SO_2 emission rate:

Ash content (%Ash): 41.425 percent by weight

For units burning coal blends:

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})	334	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.15	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.11	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	0.50	

Plant Elevation	6497	Feet above sea level

Concentration of reagent as stored (C_{stored})	29.4	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	19	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

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

Select the reagent used

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	4.75	Percent		
Fuel ($Cost_{fuel}$)	1.89	$/MMBtu*		
Reagent ($Cost_{reag}$)	2.50	$/gallon for a 29.4 percent solution of ammonia		
Water ($Cost_{water}$)	0.004	$/gallon		
Electricity ($Cost_{elect}$)	0.0821	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.8	$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

* 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)	$2.50/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Site specific information. Used the average cost of ammonia supplier costs.
Water Cost ($/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.	Site specific
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	https://www.eia.gov/electricity/state/utah/
Fuel Cost ($/MMBtu)	1.89	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.	Site specific
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	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/.	Site specific
Percent ash content for Coal (% weight)	5.84	Average ash 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/.	Site specific
Higher Heating Value (HHV) (Btu/lb)	8,826	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/.	Site specific

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 =	700	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	867,081,448	lbs/Year
Actual Annual fuel consumption (Mactual) =		883,413,174	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.20	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.93	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8167	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	15	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	15.75	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	64.31	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)	1.05	
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.27	
Atmospheric pressure at 6497 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	11.6	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.30	

* 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	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	19	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	66	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	8.8	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	3,000	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	0.0786

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)$/NPHR =	2.1	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	4	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.07	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1×10^6)/HHV =	4.4	lb/hour

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 ($SNCR_{cost}$) =	$2,062,767	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,979,238	in 2019 dollars
Total Capital Investment (TCI) =	$5,254,607	in 2019 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 ($SNCR_{cost}$) =	$2,062,767	in 2019 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 2019 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}) =	$1,979,238	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$262,629 in 2019 dollars
Indirect Annual Costs (IDAC) =	$415,377 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$678,005 in 2019 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 =	$78,819 in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$180,268 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,379 in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$142 in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$1,151 in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$870 in 2019 dollars
Direct Annual Cost =		$262,629 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,365 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$413,012 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$415,377 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$678,005 per year in 2019 dollars
NOx Removed =	64 tons/year
Cost Effectiveness =	$10,542 per ton of NOx removed in 2019 dollars

APPENDIX C : RBLC SEARCH RESULTS

Sunnyside Cogeneration Associates
Four Factor Analysis - RBLC Search

Agency/Document Title	NO_X Emissions Requirement	Control	Reference
EPA, RBLC Search	0.1 lb/MMBtu 30-day rolling average	SNCR	RBLC ID: WV-0024. Western Greenbrier Co-Generation, LLC. 1,070 MMBtu/hr firing waste coal.
	0.088 lb/MMBtu 30-day rolling average	SNCR	RBLC ID: UT-0070. Deseret Power Electric Cooperative. 1,445 MMBtu/hr firing waste coal.
	0.155 lb/MMBtu	SNCR	RBLC ID: WI-0225. Manitowoc Public Utilities. 650 MMBtu/hr firing coal/pet coke.

Agency/Document Title	SO_2 Emissions Requirement	Control	Reference
EPA, RBLC Search	0.08 lb/MMBtu 8-hour average	Limeston Injection	RBLC ID: CA-1206. Stockton Cogen Company. 730 MMBtu/hr firing coal.
	0.08 lb/MMBtu 30-day rolling average	Limestone Injection and Flash Dryer Absorption with Fresh Lime	RBLC ID: KY-0100. J.K. Smith Generating Station. 3,000 MMBtu/hr firing waste coal and coal.
	0.10 lb/MMBtu 24-hour average	Spray Dry Absorber or Polishing Scrubber	RBLC ID: MI-0400. Wolvering Power. 3,030 MMBtu/hr firing petcoke and coal.