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Ms. Chelsea Cancino
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RE: Response to UDAQ questions on Sunnyside Cogeneration Associates Four Factor Analysis

Dear Ms. Cancino:

Sunnyside Cogeneration Associates (Sunnyside) has prepared this letter in response to Utah Division of Air Quality's (UDAQ's) questions dated July 30th, 2021 (DAQP-064-21), which were in reference to the Four Factor Analysis submitted on April 8th, 2020 prepared for the second planning period of Utah's Regional Haze State Implementation Plan (SIP). The UDAQ noted a total of ten (10) questions, requests, and/or potential errors and asked that Sunnyside resubmit the Four Factor Analysis correcting the analysis. The UDAQ's concerns are re-stated below, followed by Sunnyside's responses to replace, or supplement the prior submission. The enclosed responses have been provided for clarification, revisions, and/or references to the approach in originally submitted Four-Factor Analysis. In addition, Sunnyside has provided a revised cost analyses in Attachment A to replace the cost analyses submitted in Sunnyside's originally submitted Four-Factor Analysis.

If you have further questions about these responses, please reach out Trinity Consultants, Inc. (Trinity) or Sunnyside for further information or clarification.

UDAQ'S LIST OF POTENTIAL ERRORS

1. The Sunnyside four-factor analysis for SO_2 eliminated both wet scrubbers and spray dry scrubbers from consideration as an SO_2 control because it does not have the water rights that would be needed for operation of the wet scrubber or a spray dry absorber. The Sunnyside analysis failed to evaluate the use of a circulating dry scrubber which can achieve high SO_2 removal efficiencies (as high as 98% control) with lower water use and waste compared to wet or dry scrubbers.

   Sunnyside's four-factor analysis did include a cost effectiveness analysis for a "dry scrubber," by which they were referring to dry sorbent injection. The company's analysis found that dry sorbent injection would have a cost effectiveness of $10,202/ton of SO_2 removed. More specifically, the company provided a cost analysis for a dry scrubber combined with its cost estimates for a new baghouse. A review of that cost analysis shows that there were several factors that improperly inflated the costs of a dry scrubber.

2. Sunnyside Cogen did not provide justification for including the cost for a new replacement baghouse with a dry scrubbing option.

The Sunnyside Cogen four-factor analysis of installing a dry scrubber included the costs of also installing a new baghouse, even though the CFB boiler already is equipped with a baghouse. The Sunnyside four factor analysis does not explain why a new baghouse would be required with dry scrubbing. The analysis does say that for hydrated ash reinjection, "a larger particulate control device would likely be required to handle the increased particulate matter in the flue gas." Yet, the company claimed that it did not consider hydrated ash reinjection as technically feasible for the Sunnyside CFB boiler, due to its claim that the fly ash at Sunnyside only contains 10% unreacted calcium oxide and that "even if adding reagent would be feasible it would likely require the installation of an enhanced baghouse…." However, nothing in the company's description of dry scrubbing in the four-factor analysis indicated or justified that a new baghouse would be necessary with dry scrubbing. Yet, in a subsequent section of the four-factor analysis, Sunnyside inexplicably stated that use of dry scrubbing technology at Sunnyside "also requires the installation of an additional baghouse to remove particulates generated from dry scrubbing operation." Other than this statement, there was no justification for a new baghouse for dry scrubbing provided.

Before one can determine whether an upgraded baghouse would be necessary for dry scrubbing, more information on the details of the existing baghouse and existing PM rates must be provided. It must be noted that the Sunnyside four-factor analysis indicates that the coal used at the CFB boiler has a very high ash content. This is not unusual for a CFB boilers which often burn waste coal. The existing baghouse thus had to be designed for a high level of ash content. There likely was some level of additional particulate loading built into the design of the existing baghouse. In addition, there is some evidence that a baghouse used in conjunction with sodium-based sorbents, rather than the more traditional lime-based sorbents, can achieve 70-90% SO_2 control without any increase in particulate matter loading. This option was not evaluated.

3. Sunnyside's analysis was inconsistent regarding the amount of sorbent required and the possible resulting efficiency

   The Sunnyside Cogen four-factor analysis assumed lime would be used at the reagent for the dry sorbent injection at a ratio of 3 tons of sorbent to 1 ton of SO_2 emitted and assumed 74% SO_2 control would be achieved. One table of the Sunnyside DSI cost list assumes a lime injection rate of 500 lb/hr, although the company's annual operational cost analysis assumed that 1,413 tons per year of lime would be required which, assuming the claimed baseline operating hours of 8,031 hours/year, equates to 352 lb/hr.

   Using the Sargent & Lundy formula for estimating the amount of lime needed for the Sunnyside CFB boiler and assuming that use of lime could achieve Sunnyside's planned 74% SO_2 reduction indicates that the lime injection rate would need to be 0.0921 tons per hour or 184 lb/hour, which is much lower than the 352 to 500 pounds of lime per hour assumed in the Sunnyside cost analysis for dry sorbent injection. Sunnyside should correct these inconsistencies, or at least explain which value is correct.

4. The Sunnyside dry sorbent injection analysis assumed too high of a cost for auxiliary power

   The Sunnyside Cogen analysis assumed an auxiliary power demand of 0.67% of total electrical generation. Sunnyside used the uncontrolled SO_2 emission rate for Sunnyside's CFB boiler of 1.7 lb/MMBtu rather than the currently controlled SO_2 rate claimed by Sunnyside of 0.17 lb/MMBtu in its calculations of auxiliary power demand. The dry sorbent injection system will only need to reduce SO_2 emissions from the current 0.17 lb/MMBtu rate exiting the CFB boiler, and not the uncontrolled SO_2 rate of the coal. In addition, in calculating the costs of auxiliary power, Sunnyside used an electricity cost of $74.68/MWhr, which it said is the "current revenue" from Sunnyside. The Sunnyside dry sorbent injection cost analysis also states that "[c]ost conservatively represents lost revenue from electricity that could be sold to the grid and does not include operating costs of the boiler." However, EPA's Control

Cost Manual states that the cost for auxiliary power for electrical generating units should use the busbar cost for electricity. The busbar cost is the cost of producing the electricity, not the revenue made or sale price of the electricity.

Sunnyside's cost for electricity usage due to dry sorbent injection at its CFB boiler was a significant part of its annual operating costs. At an estimated $232,862 for auxiliary power, Sunnyside's projected electricity cost was 59% of its total direct annual costs of dry sorbent injection. However, Sunnyside clearly overstated the costs for auxiliary power. Even at the Company's stated electricity cost of $74.68/MWhr, the total cost for electricity should not have been any more than the following:

0.028% x 58.33 MW x 8031 hours/yr x $74.68/MW-hr = $9,795 per year.

Sunnyside's claimed cost of $232,862 per year for electricity is almost 24 times higher than what the Sargent & Lundy IPM power formula calculates would be the auxiliary power needs using lime as the sorbent to achieve 74% SO_2 control. Clearly, Sunnyside's operational expenses are overstated.

5. The Sunnyside dry scrubbing cost analysis improperly included annual costs for taxes and insurance and assumed unreasonably high annual costs for administrative charges.

   The Sunnyside Cogen dry scrubbing analysis included annual costs for administrative charges, taxes and insurances that totaled 4% of the total capital investment. Utah has a tax exemption for air pollution controls in R307-120. There is no justification for including annual costs equating to 2% of the total capital investment for taxes. With respect to administrative costs, Sunnyside assumed annual costs of dry sorbent injection equating to 2% of the total capital investment per year which, based on the company's dry sorbent injection cost estimates, would equate to $168,020 per year. EPA does not assume anywhere near that high of an administrative cost for SCR in its SCR cost spreadsheet. Specifically, EPA estimates annual administrative charges for SCR based on the formula 0.03 x Operator Cost + 0.4 x Annual Maintenance Cost. The administrative costs for operating dry sorbent injection should not be any higher than the administrative costs for operating SCR and would likely be lower. For the dry sorbent injection system costs as presented by Sunnyside, EPA's administrative cost equation of its SCR spreadsheet would indicate the following annual administrative costs for dry sorbent injection:

   0.03 x ($22,310.63 + $3,346.59) + 0.4 x ($22,310.63+$22,310.63) = $18,741 per year

   This estimated $18,741 per year for administrative overhead is almost 9 times lower than the $168,020 per year administrative cost estimate provided by Sunnyside Cogen. Thus, it appears that Sunnyside greatly overstated annual administrative costs of operating dry sorbent injection at the Sunnyside CFB boiler.

6. The Sunnyside dry scrubbing cost analysis improperly assumed a 30% increase in cost as a retrofit factor

   The Sunnyside Cogen four-factor analysis assumed a 1.3 retrofit factor for the dry sorbent injection part of the evaluation of dry scrubbing. This same retrofit factor was also applied to the cost analysis for SCR and SNCR as well. Yet, the company did not provide any justification for application of a retrofit factor for any of these control options at the Sunnyside CFB boiler. EPA's SCR and SNCR cost spreadsheets state that "[y]ou must document why a retrofit factor of 1.3 is appropriate for the proposed project." For SNCR systems, EPA has stated no additional retrofit factor is justified for its SNCR spreadsheet, because it already applies a retrofit factor for installation of SNCR at an existing facility compared to installation at a new source. For retrofitted SCR systems, it must be noted that EPA's SCR chapter in its Control Cost Manual already provides for a 25% increase above the cost of SCR at a new greenfield coal-fired boiler in its SCR cost spreadsheet, because EPA's spreadsheet calls for use of a 0.8 retrofit factor for an SCR installation at a new facility and a "1" retrofit factor for an average SCR retrofit. Further, given that most utility boilers that have retrofitted an SCR reactor likely were not planned or designed for an SCR reactor to be installed, the average retrofit costs that EPA's SCR cost spreadsheet calculates take into account some of the difficulties like lack of space and the need to elevate the SCR.

7. The Sunnyside dry sorbent injection cost analysis used too high of an interest rate and too short, expected life when amortizing costs

   The Sunnyside dry sorbent cost analysis assumed a 7% interest rate and a 20-year life in amortizing the capital cost of this control system. The current bank prime rate is 3.25%. The Federal Reserve has indicated that it expects interest rates to remain at these low levels at least through 2023. Thus, a much lower interest rate should have been used to amortize capital costs of dry sorbent injection. Sunnyside's use of a higher than realistic interest rate would overstate the annualized capital costs by amortizing the capital costs over the life of controls at an unreasonably high interest rate.

   Sunnyside Cogen also only assumed a 20-year life for the dry sorbent injection system. EPA assumed a 30-year life of DSI in cost effectiveness calculations for this control at several Texas power plants. Sunnyside should have evaluated a 30-year life for the dry sorbent injection system.

8. Sunnyside assumed too high of an interest rate and too short of a life of controls in determining the annualized capital costs of SNCR and SCR

   The Sunnyside SCR and SNCR cost effectiveness analyses assumed a 4.75% interest rate and a 20-year life of both SCR and SNCR. While the 4.75% interest rate used in the SCR and SNCR cost analysis is much lower than the 7% interest rate used in Sunnyside's dry sorbent injection cost analysis, a 4.75% interest rate is still an unreasonably high interest rate to assume in a cost effectiveness analysis. It is unclear why a different interest rate was chosen for this analysis – at the very least one would assume the interest rates to be the same. The current prime bank rate of 3.25% should be used or the source should provide a detailed justification for using a firm-specific interest rate.

   With respect to the assumed 20-year life of SCR and SNCR, EPA has stated that the life of an SCR should be 30 years. In its SCR chapter of its Control Cost Manual, EPA included several sources for its assumed 30-year life of an SCR system at a power plant. Absent an enforceable retirement date on the remaining useful life of the Sunnyside CFB plant, it is reasonable to assume a 30-year life in estimating cost effectiveness of SCR, as EPA states in its Control Cost Manual.

9. Sunnyside assumed a very high cost for aqueous ammonia that was not justified.

   In its SNCR and SCR cost analyses, Sunnyside Cogen assumed a cost for 29.4% aqueous ammonia of $2.50 per gallon. EPA's SNCR and SCR cost spreadsheets assumes a significantly lower cost at $0.293 per gallon for 29.4% aqueous ammonia, citing to the USGS Minerals Commodities Summaries. Sunnyside provided no justification or basis for assuming a cost for aqueous ammonia that is 8.5 times higher than the cost of aqueous ammonia used in EPA's SNCR cost estimation spreadsheet, other than to put a note in the spreadsheet printouts that it was "[s]ite-specific information" and that they "[u]sed average cost of ammonia supplier costs."

10. Sunnyside assumed a higher cost for electricity than it assumed in its dry sorbent injection analysis

    In its SCR and SNCR cost analysis, Sunnyside assumed a cost for electricity of $0.0821/kW. Yet, in its dry sorbent injection analysis, Sunnyside Cogen assumed a lower electricity cost of $0.07468/kWhr, which the Company said is the "current revenue" from Sunnyside. As previously stated, it does not appear that the electricity cost used in the dry sorbent injection cost analysis was the most appropriate to use for estimating the costs of auxiliary power, as the Sunnyside cost analysis stated that the electricity "[c]ost conservatively represents lost revenue from electricity that could be sold to the grid, and does not include operating costs of the boiler." EPA's Control Cost Manual states that the cost for auxiliary power for electrical generating units should use the busbar cost for electricity. The busbar cost is the cost of producing the electricity, not the revenue made or sale price of the electricity. The company is not justified in assuming any higher of a cost for electricity for an SNCR or an SCR system than what it assumed in its DSI cost analysis.

SUNNYSIDE'S RESPONSES

Question 1

Control Technology Clarification

The UDAQ's question indicates confusion regarding the current design and available technologies due to the generic nomenclature used in the original Four Factor Analysis. Sunnyside would like to further clarify the reviewed technologies. While all of the technologies discussed utilize absorption to remove pollutants from the process gas stream, the method by which this absorption is achieved varies. These technologies can be broadly divided into two categories: wet scrubbing and dry scrubbing. As wet scrubbing, referred to as wet flue gas desulfurization (WFGD), has already been eliminated as technically infeasible due to water shortages and long-term availability, this group of technologies will not be further discussed.

Dry scrubbers, or dry sorbent injection (DSI), generically refers to the interaction of acid gas compounds, such as hydrogen chloride (HCl), SO_2, and hydgrogen sulfide (H_2SO_4), with sorbents, such as hydrated lime, sodium bicarbonate, or trona.[1] There are several methods which facilitate interaction of the acid gases and reagents including, Hydrated Ash Reinjection (HAR), Spray Dryer Absorber (SDA), and Circulating Dry Scrubber (CDS)/ Circulating Fluidized Bed Scrubber (CFBS). To provide clarification, a revised summary of these technologies and evaluation of feasibility have been provided in the following paragraphs.

Hydrated ash reinjection effectively reduces SO_2 emissions by increasing the extent of reaction between SO_2 and hydrating sorbents. This control device 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.[2]

Specifically, the circulating fluidized bed (CFB) boiler technology at Sunnyside suspends small pieces of solid fuel during the combustion process using upward blowing jets of hot air. Hot gases, carrying the coal fragments and fly ash, are recirculated through cyclones and back into the boiler chamber through the jets. In addition to coal fragments, limestone is added to the boiler. As the coal fragments and injected limestone recirculate between the boiler and the cyclones the extent of reaction between SO_2 and limestone is increased. Similarly, ash in the fuel (i.e., waste coal) has the opportunity to react with these coal fragments.

The addition of further HAR technology is not feasible as flue gas exiting the CFB boiler at Sunnyside typically contains approximately 10% unreacted calcium oxide in the fly ash and even less in the bottom ash.[3] This low amount of unreacted calcium oxide would necessitate the addition of a significant amount of

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[1] Trona is a sodium carbonate compound, which is processed into soda ash or baking soda. https://www.wyomingmining.org/minerals/trona/
[2] Montana Department of Environmental Quality, Regional Haze Four Factor Analysis, Rosebud Power Plant, 2019
[3] Based on fly ash characterization results conducted at Sunnyside Cogeneration Associates.

fly ash and would generate an even larger amount of additional particulate matter (PM). Additionally, there is a significant amount of ash already entrained in the CFB Boiler which would make additional ash infeasible. As a result, HAR is not considered further.

Spray Dryer Absorber technology sprays atomized lime slurry droplets into the flue gas. Acid gases are absorbed by the atomized slurry droplets while simultaneously evaporating into a solid particulate. The flue gas and solid particulate are then directed to a fabric filter where the solid materials are collected from the flue gas. This technology is not utilized in the current design as the addition of a slurry would inhibit combustion by increasing water content within the firebox and cyclone system. The CFB boiler design and its recirculating flue gas would alter the combustion dynamics significantly enough that the system would need to be re-engineered to accommodate this technology.

Installing an additional SDA in series with Sunnyside's current system could further reduce SO_2 emissions at Sunnyside's facility. However, despite the misleading name, SDA, requires a considerable amount of water to atomize the reactive sorbent into an aqueous solution.

Sunnyside's operation already requires a significant use of water, and not only are the plant's current water rights limited but the availability of water has reduced and is not sufficient enough to sustain the necessary water usage to operate an additional SDA. Any additional water consumption would result in the available water being used much more rapidly and represents an undue burden on the facility to acquire the water that is also limited in supply for SDA operation. As a result, 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.

Circulating dry scrubber (CDS)/Circulating fluidized bed scrubber (CFBS) is a control technique in which the waste gas stream passes through an absorber vessel containing a fluidized bed of hydrated lime and recycled byproduct.[4] Boiler flue gas enters the device at the bottom of the up-flow vessel, causing turbulent flow.[5] The turbulent flow increases mixing of the flue gas, solids, and small amounts of water to achieve a high capture efficiency of the vapor phase acid gases contained within the flue gas. The gas and solids mixture then leaves the top of the scrubber and the fabric filter removes the solid material. These controls have been documented to achieve 98% reduction of SO_2, which is consistent with what the UDAQ had stated in their potential concerns with Sunnyside's four factor analysis.

Given the configuration of existing units, there is not enough space between the CFB boiler and existing baghouse for the addition of a further CDS/CFBS unit without significant reconfiguration of existing equipment. Of all the add on control technologies considered, CDS/CFBS is the only potentially feasible option.

Existing controls for SO_2 as defined in Sunnyside's Title V air operation permit (#700030004) Condition II.A.2 currently provide SO_2 controls to the circulating fluidized bed (CFB) boiler, which involves limestone injection. Hereafter, control strategies currently implemented within the Sunnyside's CFB Boiler will be referred to as DSI using limestone. Since 1993, when the boiler was installed, Sunnyside has refined operation, limestone injection rate, and other key performance indicators to reduce SO_2 emissions.

The analysis provided under Question 1 should replace information found in Table 1-1, and Sections 5.1, 5.2, and 5.3, as applicable.

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[4] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control
[5] Power Engineering Article, Circulating Fluidized Bed Scrubber vs Spray Dryer Absorber, Circulating Fluidized Bed Scrubber vs. Spray Dryer Absorber - Power Engineering (power-eng.com)

CDS/CFBS Cost Analysis

In the original Four Factor Analysis, Sunnyside provided a cost analysis for the addition of a separate DSI unit (dry scrubber) and baghouse to ensure a comprehensive analysis of multiple options was provided. After further evaluation, a dry scrubbing unit cannot be retrofitted between the CFB boiler and the existing baghouse due to space limitations requiring significant reconfiguration of existing equipment. Accordingly, a CDS/CFBS is the only add on unit that is potentially technically feasible. Based on the additional detail provided above, and in response to the UDAQ request, a cost analysis has been completed for a CDS/CFBS to replace the DSI cost analysis.

Based on the EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, the average estimated cost for a CDS /CFBS that is able to achieve 90% or higher was $81 million with the highest being $400 million. Thus, the total capital investment has been revised. A revised cost analysis has been provided in Attachment A. Sunnyside requests that this cost for CDS/CFBS replace the cost analysis for SO_2 control in the original Four Factor Analysis.

Additionally, because the flow pathways in this control device are essential to pollutant control, this system typically includes a baghouse within the design. The current baghouse was made operational in January 1993 and is in marginal condition based on its age, requiring periodic repair to tubesheets, seals, and shell of the baghouse. This further justifies the need for replacement if alternative technologies are considered. Total cost of the baghouse replacement is estimated at $1.7 million and is insignificant compared to the total capital investment for the CDS/CFBS system as a whole. For further information please see Sunnyside's response to Question 2. Based on the revised calculations, provided in Attachment A, a CDS/CFBS device is not considered economically feasible.

Question 2

Inclusion of Baghouse in Cost Analysis

In the event that Sunnyside were to proceed with the design and installation of an additional control device, the only potentially feasible control method is the use of a CDS /CFBS as discussed in Question 1. CDS/CFBS is a control technique in which the waste gas stream passes through an absorber vessel containing a fluidized bed of hydrated lime and recycled byproduct.[6] This control device would be in addition to DSI with limestone already occurring within the CFB boiler.

Boiler flue gas enters the device at the bottom of the up-flow vessel, causing turbulent flow.[7] The turbulent flow increases mixing of the flue gas, solids, and small amounts of water to achieve a high capture efficiency of the vapor phase acid gases contained within the flue gas. The gas and solids mixture then leaves the top of the scrubber and enters the baghouse. In many cases the solids entrained in the flue gas are captured and recycled back to the scrubber to capture additional pollutants.[8] A portion of the recycled solids is removed from the baghouse in order to maintain the right quantity of material in the circulating loop. As a result, the baghouse is essential to the design and effectiveness of the a CDS/CFBS unit.

As previously mentioned, the current baghouse was made operational in January 1993, and is in marginal condition based on its age. CDS/CFBS design requires integration of the baghouse into the mixing chamber,

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[6] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control
[7] Power Engineering Article, Circulating Fluidized Bed Scrubber vs Spray Dryer Absorber, [Circulating Fluidized Bed Scrubber vs. Spray Dryer Absorber - Power Engineering (power-eng.com)]
[8] Power Engineering Article, Circulating Fluidized Bed Scrubber vs Spray Dryer Absorber, [Circulating Fluidized Bed Scrubber vs. Spray Dryer Absorber - Power Engineering (power-eng.com)]

this connection is not likely to be reliable on the existing equipment given the age of the unit. Furthermore, the addition of a CDS/CFBS would increase the amount of PM processed because it represents a secondary addition of hydrated lime to further react with pollutants.

Additionally, there is insufficient space to install a CDS/CFBS between the boiler and existing baghouse. To alter the design and re-direct the ducting into the existing baghouse from the boiler and the CDS/CFBS would require custom design plans and detailed computational fluid dynamic engineering. Even if a re-engineering of the duct work allowed the existing baghouse to be used, it is likely that the flow patterns produced by the CDS/CFBS would disrupt the flow through the plenum of the baghouse thereby redirecting air flow and eliminating the distribution of air evenly across the compartments.

These design considerations led to the conclusion that, regardless of capacity or current emission rate, inclusion of a replacement baghouse within the cost analysis was warranted. Additionally, upon utilization of a CDS/CFBS specific capital investment cost of $81 million, at a minimum, the included $1.7 million for a new baghouse becomes negligible.

Sorbent Chemistry

The UDAQ also requested that Sunnyside address the use of a sodium-based sorbent, such as sodium bicarbonate or trona, rather than the traditional lime. While "there is some evidence that a baghouse used in conjunction with sodium-based sorbents, …, can achieve 70-90% SO_2 control without any increase in particulate matter loading," changing the sorbent chemistry will not address the integration of the baghouse with the CDS/CFBS control device, the need for computational fluid dynamic engineering to ensure proper operation of the CDS/CFBS, nor the existing space requirements.

Additionally, Sunnyside did not consider the switch from a traditional lime sorbent to a sodium-based sorbent because sodium-based sorbents have not been considered best industry practice for at least the last 20 years. This is demonstrated by a review of the RBLC, section 1.11, which identifies only lime-based sorbents. Moreover, the control efficiency of any sorbent is dependent on the flue gas properties, sorbent size, mixing of sorbent and pollutants, as well as various other control system configurations. Sunnyside has optimized these parameters within its current DSI limestone system to maximize control efficiency while maintaining CFB boiler operation. Therefore, consideration of absorbents is eliminated from further evaluation.

Question 3

Sunnyside has updated this formula in the revised cost analysis to utilize the Sargent & Lundy formula for estimating the amount of lime needed for the Sunnyside CFB boiler. This formula now assumes that use of lime could achieve 74% SO_2 reduction resulting in a lime injection rate of 0.0921 tons per hour or 184 lb/hour.

Question 4

Sunnyside has revised the cost for auxiliary power to be consistent with the UDAQ comments. Specifically, the busbar cost for electricity has now been calculated based on 2018 operating data. The resulting rate is $49.45 per MW.

Additionally, the electrical usage rate has been updated to match the UDAQ comments and as displayed below:

0.028% x 58.33 MW x 8031 hours/yr x $49.45/MW-hr = $6,486 per year.

The analysis provided under Question 2, 3, and 4 along with the attached cost analysis should replace information found in Sections 5.4 and 5.5 of the Four Factor Analysis.

Question 5

Tax Rate

The UDAQ suggested that there are tax exemptions in Utah for control equipment. UAC R307-120 exempts the purchase of control equipment from sales/use tax. As a result, sales tax is no longer included in CDS/CFBS cost analysis provided.

Property taxes are still assessed for control equipment and are not addressed under UAC R307-120, therefore this tax rate has been taken from the EPA Cost Control Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, Subsection 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs.

Sales tax rates and property taxes are not used in either the SCR or SNCR cost analyses due to the equation format provided by EPA.

Insurance

Insurance rate was based on a 1% of the Total capital investment (TCI) which is documented in the EPA Cost Control Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, Subsection 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs.

Administrative Costs

The administrative cost calculation has been updated to be consistent with SCR as suggested by the UDAQ. Specifically, the following formula was used: 0.03 x Operator Cost + 0.4 x Annual Maintenance Cost.

Question 6

The UDAQ questioned the retrofit factor (RF) of 1.3 used all cost analyses, as a result Sunnyside re-evaluated the use of this factor on a technology specific basis.

CDS/CFBS

The estimated cost provided in EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, represents the estimated cost for a CDS /CFBS that is able to achieve 90% or higher. This cost includes contingency for a simple retrofit. EPA states that for retrofits that are more complicated than average, a retrofit factor of greater than 1 can be used to estimate capital costs, provided the reasons for using a higher retrofit factor are appropriate and fully documented.[9] The bounds given for the RF on a dry system are 0.8 to 1.5. [10] EPA further documents that the retrofit factor should

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[9] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Subsection 1.2.3.5

[10] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Subsection 1.2.3.5

account for site congestion, site access, and capacity of existing infrastructure. The amount of space available near the utility boiler can significantly impact the costs.[11]

In order to install a CDS/CFBS system the site would need to decommission the existing baghouse and utilize architectural and mechanical experts to fit both the CDS/CFBS and a new baghouse within the currently allocated space. Additionally, because the flow mechanics, namely turbulence, are key to the control efficiency, an outside contractor would need to ensure fluid mechanics were compatible. Sunnyside anticipates that these considerations would likely lead to a custom design and would justify the 1.3 retrofit factor.

SCR

The procedures for estimating costs presented in EPA's Cost Control Manual, Section 4 NOx Controls, Chapter 2 Selective Catalytic Reduction are based on cost data for SCR retrofits on existing coal-, oil-, and gas-fired boilers for electric generating units larger than 25 MWe (approximately 250 MMBtu/hr). Thus, this report's procedure estimates costs for typical retrofits of such boilers.

As mentioned in the original Four Factor Analysis, since low-temperature SCR is not technically feasible, implementation of SCR can only be implemented if the flue gas is reheated downstream of the baghouse. This heating is necessary to ensure an operable temperature range. The installation of an additional combustion device, including additional engineering and capital investment, is not standard for the retrofit of this technology. As a result, a 1.3 retrofit factor has been utilized. A revised cost analysis has been provided in Attachment A to replace the cost analysis submitted in the Sunnyside Four-Factor Analysis. It should be noted that this cost analysis represents estimates based on information available at the time.

SNCR

The costing algorithms in presented in EPA's Cost Control Manual, Section 4 NOx Controls, Chapter 1 Selective Non-Catalytic Reduction are based on retrofit applications of SNCR to existing coal-fired utility boilers. EPA stated that over the years, SNCR has begun to be applied to existing sites that are more difficult to retrofit, which means the gap between average retrofit and new installation costs may be greater than it used to be, but it is not expected to be substantial.

Because this technology could be implemented within the boiler, rather than as a stand-alone control device the flue gas path, Sunnyside anticipates that should this application be installed it would likely be considered a standard retrofit project. As a result, the 1.3 retrofit factor has been replaced by a 1.0 retrofit factor. A revised cost analysis has been provided in Attachment A to replace the cost analysis submitted in the Sunnyside Four-Factor Analysis. It should be noted that this cost analysis represents estimates based on information available at the time and further investigation may be required.

Question 7

Equipment Life

While EPA generally recommends a 30 year equipment life, the EPA Cost Control Manual states that for retrofits on older combustion units, the remaining life of the controlled combustion unit may be an important factor for determining the expected lifetime for a dry scrubber.[12] Additionally, the EPA issued

[11] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Subsection 1.2.3.5
[12] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Indirect Annual Costs (pg. 1-35)

Reasonable Progress Source Identification and Analysis Protocol (WRAP) for Second 10-year Regional Haze State Implementation Plans, which further supports this statement by adding "States should combine and annualize these costs over the expected life of the source or the control equipment, whichever is shorter." The document then goes on to state:

> *"Generally, the remaining useful life of the source itself will be longer than the useful life of the emission control measure under consideration unless there is an enforceable requirement for the source to cease operation sooner. Thus, states should normally use the useful life of the control measure to calculate emission reductions, amortized costs, and cost per ton. However, if there is an enforceable requirement for the source to cease operation by a date before the end of what would otherwise be the useful life of the control measure under consideration, then states should use the enforceable shutdown date to calculate remaining useful life"*

The Sunnyside Plant was originally commissioned in the early 1990s, thus the plant has already been running for approximately 30 years. Due to equipment aging, it is estimated that CFB boiler will not be operating beyond an additional 20 years. Thus a 20-year life span has been applied to the cost control analyses provided.

Interest Rate

The EPA cost manual states that "when performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face."[13]

For this analysis, which evaluates equipment costs that may take place more than 5 years into the future, it is important to ensure that the selected interest rate represents a longer-term view of corporate borrowing rates. The cost manual cites the bank prime rate as one indicator of the cost of borrowing as an option for use when the specific nominal interest rate is not available.

Over the past 20 years, the annual average prime rate has varied from 3.25% to 9.23%, with an overall average of 4.86% over the 20-year period.[14] But the cost manual also adds the caution that the "base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers."[15] For this reason, the prime rate should be considered the low end of the range for estimating capital cost recovery.

Actual borrowing costs experienced by firms are typically higher. For economic evaluations of the impact of federal regulations, the Office of Management and Budget (OMB) uses an interest rate of 7%.

> *"As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost*

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[13] EPA Cost Control Manual, Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology
[14] Board of Governors of the Federal Reserve System Data Download Program, "H.15 Selected Interest Rates," accessed April 16, 2020. https://www.federalreserve.gov/datadownload/Download.aspx?rel=H15&series=8193c94824192497563a23e3787878ec&filetype=spreadsheetml&label=include&layout=seriescolumn&from=01/01/2000&to=12/31/2020
[15] EPA Cost Control Manual, Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology

> *of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector."*[16]

Based on this guidance, Sunnyside now uses a 7% interest rate in all cost analyses provided.

Question 8

The equipment life and interest rate explanations provided in Question 7 are not control technology specific. Thus, the same conclusions are applicable, namely, a 20-year life span and 7% interest rate are appropriate for the cost analyses provided.

Question 9

In response to the UDAQ's request, Sunnyside obtained a cost estimate for 19% aqua ammonia from Thatcher Group, Inc (Thatcher). Thatcher quoted $0.18 per lb. of solution. Based on this value, if we assume a density of 19% ammonia is estimated to be 7.46 lbs/gal to 7.99 lbs/gal. This results in a cost per gallon ranges from 1.34 $/gal to 1.438 $/gal. This cost is significantly higher than the EPA estimate of $0.293, which is acceptable as it states, "User should enter actual value if known". Furthermore, it should be noted that the cost for ammonia based on the most recent U.S. Geological Survey, Minerals Commodity Summaries, which was quoted in the original Four Factor Analysis is also significantly higher and based on a density of 29% ammonia. Since the $1.438 is still less than the originally used $2.5 per gallon, these calculations have been updated to include the vendor quote.

Question 10

As discussed in Question 4, Sunnyside has revised the cost for auxiliary power to be consistent with the UDAQ's comments. Please see section 4 for additional information.

A revised cost analysis for SCR and SNCR have been provided in Attachment A to replace the cost analysis in the original Four Factor Analysis.

[16] OMB Circular A-4, https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf - "

Attachment A - Revised Cost Analyses

Dry Scrubber Cost Analysis
Table A-1: CDS/CFBS

Variable		Value	Units
Baseline SO_2 Emissions		471	tons/year
SO_2 Removal Efficiency		74%	
Total SO_2 Removed		318.91	tons/year
Lime Injection Rate		184	lb/hr (Sargent & Lundy)
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	$66,600,000.00	EPA Cost Control Manual, Section 5 SO2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, with a ratio applied to be consistent with the 74% control orginally estimated
Instrumentation	0.1×A	$6,660,000.00	Per EPA Control Cost Manual
Sales Tax		$0.00	Assume tax exempt per UDAQ Rules
Freight	0.05×A	$3,330,000.00	Per EPA Control Cost Manual
Purchased equipment cost, PEC	B = 1.18×A	$76,590,000.00	Per EPA Control Cost Manual
Direct Installation Costs			
Foundation and Supports	0.12×B	$9,190,800.00	Per EPA Control Cost Manual
Handling and Erection	0.40×B	$30,636,000.00	Per EPA Control Cost Manual
Electrical	0.01×B	$765,900.00	Per EPA Control Cost Manual
Piping	0.3×B	$22,977,000.00	Per EPA Control Cost Manual
Installation for ductwork	0.01×B	$765,900.00	Per EPA Control Cost Manual
Painting	0.01×B	$765,900.00	Per EPA Control Cost Manual
Direct Installation Cost	0.85×B	$65,101,500.00	Per EPA Control Cost Manual
Retrofit Factor	1.3		Per EPA Control Cost Manual
Direct Installation Costs Including Retrofit Factor		$84,631,950.00	
Site Preparation			As required, estimate
Buildings			As required, estimate
Total Direct Cost	1.30×B + SP + Bldg + Direct Costs	$161,221,950.00	Direct costs include foundation, handling, electrical, piping, ductwork, and painting
Indirect Costs (Installation)			
Engineering	0.10×B	$7,659,000.00	Per EPA Control Cost Manual
Construction and Field Expenses	0.10×B	$7,659,000.00	Per EPA Control Cost Manual
Contractor Fees	0.10×B	$7,659,000.00	Per EPA Control Cost Manual
Start-up	0.01×B	$765,900.00	Per EPA Control Cost Manual
Performance Test	0.01×B	$765,900.00	Per EPA Control Cost Manual
Contingencies	0.03×B	$2,297,700.00	Per EPA Control Cost Manual
Total Indirect Cost, IC	0.35×B	$26,806,500.00	Per EPA Control Cost Manual
Total Capital Investment (TCI)	TCI = DC + IC	$188,028,450.00	

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		$3,346.59	15% of Operator
Operating Materials			
Lime required (tpy)		739	Lime required (tpy) = SO_2 emissions (tpy) × 3
Limestone Cost ($/ton)		55.81	Current costs from Sunnyside's Limestone supplier
Limestone Cost ($/yr)		$41,235.33	Annual Cost ($/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			
Rate		$49.45	($/MW) Total annual Busbar cost divided by MW produced from Sunnyside
Electricity		$6,485.54	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		$117,999.34	
Indirect Annual Costs, IC			
Overhead	60% sum of operating labor, maintenance labor, and associated materials	$42,167.08	
Administrative Charges	= 0.03 x Operator Cost + 0.4 x Annual Maintenance Cost.	$25,545.67	Where the TCI is estimated as $66600000
Property Taxes	1% of TCI	$1,880,284.50	Where the TCI is estimated as $66600000
Insurance	1% of TCI	$1,880,284.50	Where the TCI is estimated as $66600000
Indirect Annual Cost		$3,828,281.75	Sum of overhead, administrative, taxes, and insurance
Capital Recovery[2]		$0.09	$ Annually/$ Capital Cost
Annualized Capital Cost		$17,748,555.52	Capital Recovery * Total Capital Investment
Total Annual Cost (Dry Scrubber)		$21,694,836.60	$/year
Cost Effectiveness		$68,027.21	$/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.

[2] Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs

Interest	7.00%
Based on CFB Boiler Equipment Life (Life of the Unit)	20

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

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

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.30

* 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: Sub-Bituminous

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

For units burning coal blends:

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

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

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

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

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

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	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	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516.00	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	19	percent
Density of reagent as stored (ρ_{stored})	57.783	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019				
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent			
Reagent ($Cost_{reag}$)	1.380	$/gallon for 19% ammonia			
Electricity ($Cost_{elect}$)	0.0495	$/kWh			
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	40.75	$/hour (including benefits)			
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	Revised Cost: $1.38/gallon Initial Cost: ~~$2.50/gallon of 29% Ammonia~~	Revised cost analysis: Quotation from Thatcher (Average cost based on density range.) Initial cost analysis: ~~U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf~~	Site specific infomration. Used average cost of ammonia supplier costs
Electricity Cost ($/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.	Busbar cost and production rate for 2018 used.
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)	7	See explanation in summary	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} =	345,631	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 = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3111	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 =	57.783 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 =	198	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	26	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	8,700	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	0.0944

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) =	$995,457	in 2019 dollars
Indirect Annual Costs (IDAC) =	$4,810,962	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$5,806,419	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} =	$315,628	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$191,082	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 =		$995,457	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 =	$4,806,274	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$4,810,962	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$5,806,419	per year in 2019 dollars
NOx Removed =	432	tons/year
Cost Effectiveness =	$13,445	per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

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

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.00

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? Yes

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: Sub-Bituminous

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

or

Select the appropriate SO_2 emission rate: Not Applicable

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	Plant Elevation	6497	Feet above sea level
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.15	lb/MMBtu			
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.13	lb/MMBtu			
Estimated Normalized Stoichiometric Ratio (NSR)	0.50				

Concentration of reagent as stored (C_{stored})	19	Percent
Density of reagent as stored (ρ_{stored})	57.783	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
Select the reagent used	Ammonia	

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019				
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent			
Fuel ($Cost_{fuel}$)	1.89	$/MMBtu*			
Reagent ($Cost_{reag}$)	1.38	$/gallon for a 19 percent solution of ammonia			
Water ($Cost_{water}$)	0.004	$/gallon			
Electricity ($Cost_{elect}$)	0.0495	$/kWh			
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.8	$/ton*			

* 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)	Revised Cost: $1.38/gallon Initial Cost: ~~$2.50/gallon of 29% Ammonia~~	Revised cost analysis: Quotation from Thatcher (Average cost based on density) Initial cost analysis: ~~U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf~~	Site specific information. Used the average cost of ammonia supplier costs.
Water Cost ($/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 ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	Busbar cost and energy production rate from 2018 used.
Fuel Cost ($/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
Interest Rate (%)	7	See attached summary	Federal Bank Prime Loan Rate

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	1.00	

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

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	57.783 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	19	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	102	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	13.2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	4,500	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	0.0944

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	2.1	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.07	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/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 ($SNCR_{cost}$) =	$1,586,744 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,522,491 in 2019 dollars
Total Capital Investment (TCI) =	$4,042,005 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 ($SNCR_{cost}$) =	$1,586,744 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}) =	$1,522,491 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$212,706 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$383,384 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$596,090 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 =	\$60,630 in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	\$149,224 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	\$830 in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	\$0 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 =		\$212,706 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$1,819 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$381,565 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$383,384 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$596,090 per year in 2019 dollars
NOx Removed =	64 tons/year
Cost Effectiveness =	\$9,268 per ton of NOx removed in 2019 dollars