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<u>Submitted via electronic mail</u>

March 31, 2020

Daniel Czecholinski
Director, Air Quality Division
Arizona Department of Environmental Quality
1110 W. Washington St.
Phoenix, AZ 85007

RE: Irvington Generating Station Four Factor Analysis Report

Dear Mr. Czecholinski:

Tucson Electric Power Company (TEP) respectfully submits the attached *Identification and Evaluation of Emission Control Measures for the Irvington Generating Station*, to the Arizona Department of Environmental Quality (ADEQ).

This report is intended to provide information that is relevant to ADEQ's demonstration, as required by the Federal Clean Air Act (CAA),[1] that Arizona is making reasonable progress toward the national goal of remedying any existing impairment of visibility in mandatory Class I Federal areas, which impairment results resulting from manmade air pollution. Specifically, TEP provides this report for ADEQ's use in developing a revised State Implementation Plan (SIP) for the second planning period under the federal Regional Haze (RH) program.

Background

TEP owns and operates electric generation, transmission, and distribution assets that safely and reliably serve approximately 428,000 customers with affordable electricity in Southern Arizona including the Irvington Generating Station (IGS), also known as the H. Wilson Sundt Generating Station, which is located in Tucson, Arizona, and is the subject of the attached report.

The IGS includes two fossil fuel-fired electric utility steam generating units, designated as Units 3 and 4; two simple cycle combustion turbines; ten reciprocating internal combustion engines; and various ancillary units. All units are owned and operated by TEP.

[1] 42 U.S.C. § 7401 et seq.

Summary of Four Factor Analyses

Based on direction received from ADEQ, the analysis summarized in this report covers only nitrogen oxides (NO_x) emissions from IGS Unit 3. Emissions from Unit 3 of pollutants other than NO_X are negligible and all other units at the IGS are either already equipped with the most effective controls or have negligible emissions of all visibility-impairing pollutants.

The attached report was prepared by RTP Environmental Associates, Inc. (RTP). The analysis addresses the four factors that ADEQ must consider under the RH provisions of the CAA[2] and the implementing federal regulations,[3] i.e., the costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements.

The thorough analyses documented in the attached RTP report shows that retrofitting combustion controls designed to reduce NO_x formation at Unit 3 is a feasible control measure to reduce NO_x emissions from that unit, and that this measure may be reasonably cost effective on a dollars-per-ton basis. As stated in the RTP report, if retrofitting combustion controls are necessary, further evaluation will be required in order to determine emission limits achievable with this control measure.

In determining whether the NO_x emission reductions achievable with combustion controls are necessary to make reasonable progress in the second planning period, ADEQ must give consideration not only to the cost effectiveness in terms of dollars per ton of emission reduction but also to the visibility improvement that would result from these emission reductions. At the time of submittal of this report, no modeling of potential visibility improvement due to emissions reductions from the IGS has been performed for the second planning period. However, based on modeling performed for other facilities in Arizona, RTP expects the NO_x emission reductions achievable with combustion controls at Unit 3 at the IGS are much less cost-effective in relation to the small visibility benefits that would be achieved than in terms of cost per ton of emission reduction. As a general matter, the negligible visibility benefits of potential control measures at IGS Unit 3 is, by itself, a sufficient basis for concluding that no new control measures at IGS Unit 3 are necessary to make reasonable progress toward the national visibility goal. In addition, as ADEQ is aware, EPA's PGM modeling shows nearly all of the mandatory Class I Federal areas in Arizona and surrounding states are already at or below the uniform rate of progress line – the "glidepath" – toward the national visibility goal.[4] Thus, ADEQ need not consider or require extraordinary control measures, such as those that are not cost effective in relation to historical norms, as may be required under the remedial "robust demonstration" provisions of the RH program.[5]

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[2] 42 U.S.C. § 7491(g)(1).

[3] 40 CFR § 51.308.

[4] U.S. EPA, *Technical Support Document for EPA's Updated 2028 Regional Haze Modeling* (Sept. 2019) www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf.

[5] 40 CFR § 51.308(f)(3)(ii).

The RTP report for IGS Unit 3 also demonstrates conclusively that all other control measures potentially available for this unit are not cost-effective, even on a dollars-per-ton basis, and are not required in order to make reasonable progress toward the national visibility goal.

If you have any questions regarding these submittals, please feel free to contact me or Catherine Schladweiler.

Sincerely,

Erik Bakken
Vice President, System Operations & Environment

cc: Rupesh Patel, Pima County Department of Environmental Quality
Mark Mansfield, TEP

Identification and Evaluation of Emission Control Measures for the Irvington Generating Station for Purposes of the Regional Haze Second Planning Period Under 40 CFR § 51.308(f)(2)

Prepared by:

RTP Environmental Associates, Inc.
304-A West Millbrook Rd.
Raleigh, NC 27609

March 2020

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Appendix A	EPA Cost Spreadsheets for SCR and SNCR

1. Introduction and Background

1.1 Introduction

This report presents an analysis of potential control measures that could be used to achieve emission reductions in visibility-impairing pollutants at the Irvington Generating Station ("IGS"), also known as the H. Wilson Sundt Generating Station, located in Tucson, Arizona.

The IGS includes two fossil fuel-fired electric utility steam generating units, designated as Units 3 and 4; two simple cycle combustion turbines; ten reciprocating internal combustion engines; and various ancillary units. All units are owned and operated by Tucson Electric Power Company ("TEP").

TEP hired RTP Environmental Associates, Inc. ("RTP") to prepare the analysis presented herein. The analysis is provided in response to a request by Arizona Department of Environmental Quality ("ADEQ") to assist in developing a long-term strategy for demonstrating that Arizona is makng reasonable progress under the Regional Haze program as discussed below.

1.2 Statutory and Regulatory Background

The Federal Clean Air Act ("CAA") establishes as a national goal "the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution"[1] and requires States periodically to develop plans for making reasonable progress toward meeting the national goal.[2] The statute further requires that, in determining what constitutes reasonable progress, "there shall be taken into consideration the costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements."[3] These are referred to as the four reasonable progress factors or simply the four factors.

The U.S. Environmental Protection Agency ("EPA") has promulgated prescriptive Federal rules establishing minimum requirements concerning the timing and content of the initial Regional Haze State Implementation Plan ("SIP") for each State and for periodic, comprehensive revisions.[4] Each SIP revision must be submitted to EPA; if it is not approved, then EPA may have authority to develop a Federal Implementation Plan ("FIP") to meet the statutory requirements.[5] ADEQ developed and submitted the initial Regional Haze SIP for Arizona

[1] 42 U.S.C. § 7491(a)(1).
[2] *See generally* 42 U.S.C. § 7491(b)(2).
[3] 42 U.S.C. § 7491(g)(1).
[4] 40 CFR § 51.308.
[5] *See generally* 42 U.S.C. § 7410(c)(1).

addressing reasonable progress for the first implementation period in 2011.[6] This SIP was partially approved and partially disapproved, leading EPA to promulgate a Regional Haze FIP for Arizona in 2014.[7] The FIP included emission limits for Unit 4 at the IGS.[8] EPA approved ADEQ's determination that no additional controls were required for Unit 3 at the IGS during the first implementation period.[9]

Regional Haze SIPs establishing a long-term strategy for the second implementation period, which ends in 2028, must be submitted to EPA by July 31, 2021.[10] The State's submittal must include, among other things:

- The enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress;[11]
- A description of how the four factors listed in the statute (*i.e.*, costs of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source) were considered in evaluating and determining the emission reduction measures that are necessary to make reasonable progress;[12]
- A demonstration that the State has included in its SIP all measures agreed to during the State-to-State consultation process or the regional planning process, or measures that will provide equivalent visibility improvement, as well as documentation of the State's consideration of measures that other States identified as necessary to make reasonable progress for their sources;[13]
- Documentation of the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary;[14] and
- A description of the State's consideration of the five additional factors listed in 40 CFR § 51.308(f)(2)(iv), including the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions during the planning period.[15]

The objectives and content of the required periodic SIP revisions were summarized succinctly in the 2011 Arizona RH SIP:

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[6] ADEQ, Air Quality Division, *Arizona State Implementation Plan: Regional Haze Under Section 308 of the Federal Regional Haze Rule* (Jan. 2011) https://legacy.azdeq.gov/environ/air/haze/download/haze308sip.pdf ("2011 Arizona RH SIP"). Arizona had previously submitted a Regional Haze SIP under the alternative provisions of 40 CFR § 51.309, but this SIP was never approved by EPA.

[7] 79 *Fed. Reg.* 52420 (Sept. 3, 2014).

[8] *See* 40 CFR § 52.145(j).

[9] *See* 78 *Fed. Reg.* 46142 (July 30, 2013).

[10] 40 CFR § 51.308(f). Note that this deadline was originally July 31, 2018, and was extended by three years in a recent rulemaking. *See* 82 *Fed. Reg.* 3078 (Jan. 10, 2017).

[11] *See Id.*

[12] 40 CFR § 51.308(f)(2)(i).

[13] 40 CFR § 51.308(f)(2)(ii).

[14] 40 CFR § 51.308(f)(2)(iii).

[15] 40 CFR § 51.308(f)(2)(iv)(E).

> Determine the effectiveness of the long-term strategy for achieving the presumptive goal for the prior SIP period. If the long-term strategy or prior presumptive goal was insufficient to attain natural conditions by 2064, the state/tribe must look at additional or new control measures that may be adopted considering compliance cost, compliance time, compliance energy and non-air quality environmental impacts, and the affected source remaining useful life.[16]

In January 2017, EPA significantly revised the Regional Haze rule, including the provisions that govern implementation of the program during the second planning period and subsequent planning periods.[17] In August 2019, EPA issued guidance for consideration by States in developing Regional Haze SIPs for the second implementation period.[18] In September 2019, EPA released modeling results and a Technical Support Document demonstrating that many Class I areas are already on track to attain natural conditions by 2064, i.e., that those Class I areas are at or below the "glidepath" to natural conditions.[19] That modeling further demonstrates that the majority of Class I areas are below the glidepath when it is adjusted to reflect the impacts of international anthropogenic emissions as provided for in EPA's rules.

ADEQ has recently begun a stakeholder process for development of the Regional Haze SIP for the second implementation period.[20] Neither the CAA nor any Federal or State regulation expressly requires the evaluation of emission reduction measures for individual facilities.[21] However, ADEQ has indicated that it will perform such facility-specific analyses and will consider analyses prepared by the owners and operators of those facilities.[22]

1.3 Background Regarding IGS and Unit 3

As noted in Section 1.1 above, the IGS includes fourteen electric generating units. Based on direction received from ADEQ, the analysis summarized in this report covers only nitrogen oxides (NO_X) emissions from Unit 3. Emissions from Unit 3 of pollutants other than NO_X are negligible and all other units at the IGS either are already equipped with the most effective controls or have negligible emissions of all visibility-impairing pollutants.

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[16] *See* 2011 Arizona RH SIP, *supra* note 6, at 211.

[17] 82 *Fed. Reg.* 3078 (Jan. 10, 2017).

[18] U.S. EPA, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (EPA-457/B-19-003) (Aug. 2019) https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period ("2nd Period Regional Haze Guidance").

[19] U.S. EPA, *Technical Support Document for EPA's Updated 2028 Regional Haze Modeling* (Sept. 2019) www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf.

[20] *See generally*, ADEQ, 2021 Regional Haze SIP Planning, https://azdeq.gov/node/5377.

[21] *See* 82 *Fed. Reg.* 3078, 3088 (Jan. 10, 2017) ("Neither the 1999 RHR nor the revised regulations in this rulemaking require states to conduct four-factor analyses on a source-specific basis…. Thus, the EPA has consistently interpreted the CAA to provide states with the flexibility to conduct four-factor analyses for specific sources, groups of sources or even entire source categories, depending on state policy preferences and the specific circumstances of each state.")

[22] *See, e.g.*, e-mail message from Ryan Templeton, ADEQ, to Catherine Schladweiler, TEP, Sept. 24, 2019 and e-mail message from Valerie Thorsen, ADEQ, to Catherine Schladweiler, TEP, Nov. 14, 2019.

Unit 3 at the IGS began commercial operation in 1962 and has a nameplate electric generating capacity of 113.6 megawatts ("MWe"). The unit includes a tangentially fired boiler that was originally designed to burn both oil and natural gas and now burns natural gas exclusively.

1.4 Analysis Process

The federal Regional Haze rule does not prescribe a methodology which ADEQ must follow in determining the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress; the primary requirements are that the evaluation include consideration of the four factors listed in the statute (*i.e.*, costs of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source), that the evaluation is supported with adequate documentation, and that the evaluation is reasonable.[23] The analysis presented in this report generally follows the steps outlined in EPA guidance.[24]

The first step in the analysis for a particular source is to identify the technically feasible control measures for those pollutants that contribute to visibility impairment.[25] EPA guidance indicates that for reasonable progress, a State need only "reasonably pick and justify the measures that it will consider."[26] One potentially informative definition can be found in long-standing EPA guidance in the context of Best Available Control Technology ("BACT") determinations under the Prevention of Significant Deterioration ("PSD") program, which explains that, for purposes of that program, a technically feasible control measure is one that has been demonstrated to function efficiently on a source or unit that is identical or similar to the source or unit under review.[27]

The second step in the analysis involves development of emissions-related information for the source under review.[28] This includes both a baseline scenario and, for each control measure under consideration, characterization of the emissions reductions and emissions limitations that may be achievable at the source.[29]

The third step in the analysis involves characterization of the cost of compliance for each control measure (*i.e.*, each set of emissions limitations) under consideration.[30] This is the first of the four statutory factors. The analytical approach to cost estimation described in Chapter 2 of Section 1 of EPA's Air Pollution Control Cost Manual, including the use of the so-called overnight method for accounting for capital investments, while nonbinding,[31] is generally

[23] *See* 2nd Period Regional Haze Guidance, *supra* note 18, at II.B.3.
[24] *See generally* 2nd Period Regional Haze Guidance, *supra* note 18, at 28-45.
[25] *See Id.* at pp. 28-29.
[26] *Id*. at 29.
[27] *See* U.S. EPA, *Prevention of Significant Deterioration Workshop Manual* (EPA-450/2-80-081) (Oct. 1980) at I-B-6 through I-B-7, https://nepis.epa.gov/Exe/ZyPDF.cgi/2000Z81A.PDF?Dockey=2000Z81A.pdf.
[28] *See* 2nd Period Regional Haze Guidance, *supra* note 18, at 29-30.
[29] *Id.*
[30] *See Id.* at 31.
[31] *See* 79 *Fed. Reg.* 52420, 52466 (Sept. 3, 2014) (noting that "nothing in the [Regional Haze Rule] requires use of the [Control Cost Manual] for calculating the cost of compliance for [reasonable progress] sources").

followed in this evaluation. For certain types of add-on air pollution control equipment, the Control Cost Manual includes recommended methodologies and factors for estimating capital and operating costs.[32,33] In order to ensure the cost information is meaningful for purposes of evaluating whether any of the control measures under consideration are necessary to make reasonable progress, both absolute costs (*e.g.*, capital costs and total annualized cost) and relative costs (*e.g.*, incremental cost per incremental ton of emission reduction and incremental cost per incremental inverse megameter, or per deciview, of visibility improvement) are presented.[34]

The fourth step in the analysis involves, for each control measure remaining under consideration, characterization of the time necessary for compliance.[35] This is the second of the four statutory factors. EPA has recommended that States consider this factor in making a determination as to when compliance can be achieved, not whether it is necessary to make reasonable progress.[36]

The fifth step in the analysis involves, for each control measure remaining under consideration, characterization of the energy and non-air quality environmental impacts of compliance and the remaining useful life of the source or unit under review.[37] These are the remaining two of the four statutory factors. In the evaluation of whether a particular control measure is necessary to make reasonable progress, these statutory factors may generally be considered as part of a State's characterization of the costs of compliance.[38]

The sixth step in the analysis involves, for each control measure remaining under consideration, characterization of the visibility improvement (*e.g.*, in units of inverse megameters or delta deciviews) that would result from installation and operation of such control measure.[39] Although

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[32] Mussatti, David, et. al, U.S. EPA, *EPA Air Pollution Control Cost Manual, Sixth Edition* (EPA/452/B-02-001) (Jan. 2002), https://www3.epa.gov/ttn/ecas/docs/cs1ch2.pdf ("Control Cost Manual"). The sixth edition is the most up-to-date, complete edition of this guidance document. U.S. EPA also is developing and making available on its internet web site individual chapters of the upcoming 7th edition at www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[33] The calculation methodologies presented in the Control Cost Manual consistently use 7.0 percent as the real or "social" interest rate, as prescribed by Circular No. A-94, "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs." *See* Control Cost Manual, *supra* note 33 at 2-13, 4-22. The same 7.0 percent interest rate has been consistently used for control technology determinations under the Regional Haze program. *See generally,* ADEQ, *Arizona Best Available Retrofit Technology (BART) Analysis and Determination: Technical Support Document* (May 2013) http://static.azdeq.gov/aqd/haze/2013_308_revison.pdf ("ADEQ BART Technical Support Document"); *See also,* U.S. EPA Region IX, *Arizona Regional Haze Technical Support Document* (Jul. 2012), https://www3.epa.gov/region9/air/actions/pdf/az/arizona-rh-tsd-final.pdf ("AZ RH Technical Support Document"). Using a lower interest rate as the basis for a decision to require additional control measures in the second planning period would be arbitrary, capricious, and inappropriate. Nonetheless, and solely for the purposes of being consistent with the methodology suggested by EPA's cost spreadsheets discussed in Sections 4.2 and 4.3 of this report and presented in Appendix A to this report, RTP and TEP have conservatively used a nominal interest rate of 5.25 percent for all cost analyses presented herein. This should not be construed as an admission that use of an interest rate lower than 7.0 percent is appropriate or permissible.

[34] *See* 2nd Period Regional Haze Guidance, *supra* note 18, at 29, 31.

[35] *See Id.* at 32.

[36] *See Id.* at 41.

[37] *See Id.* at 33.

[38] *See Id.* at 41-42.

[39] *See* 2nd Period Regional Haze Guidance, *supra* note 18, at 16, 35.

visibility improvement is not one of the four reasonable progress factors, EPA guidance states expressly that such benefits can be considered as part of a four factor analysis "to inform the determination of whether it is reasonable to require a certain measure."[40] For purposes of determining whether a particular control measure is necessary to make reasonable progress, these potential visibility improvements are considered in relation to the reasonable progress goals.[41]

[40] *See* 2nd Period Regional Haze Guidance, *supra* note 18, at 34.
[41] *See supra* note 16.

2. Analysis Step 1: Identification of Technically Feasible Control Measures

As discussed in Section 1.4 above, the first step in the reasonable progress analysis for a particular source involves identification of technically feasible control measures for those pollutants that contribute to visibility impairment.

The pollutants emitted by Unit 3 at the IGS that have the potential to impair visibility are NO_X, sulfur dioxide (SO_2), particulate matter ("PM"), and volatile organic compounds ("VOC").[42] However, based on direction received from ADEQ, because emissions of pollutants other than NO_X from Unit 3 are negligible, only NO_X is covered in this analysis.

Potential control measures for NO_X, and the technical feasibility of those measures, are discussed in the following subsections.

2.1 Low-NO_X Burners, Flue Gas Recirculation, and Other Combustion Controls

Unit 3 at the IGS has not been retrofitted with low-NO_X burners, flue gas recirculation, or other combustion controls for the purpose of reducing NO_X formation. Improvement in control of NO_X emissions through retrofit of low-NO_X burners and/or other combustion controls is technically feasible.

2.2 Selective Non-Catalytic Reduction System

Unit 3 at the IGS is not equipped with a selective non-catalytic reduction ("SNCR") system. Improvement in control of NO_X emissions from Unit 3 through retrofit of an SNCR system is technically feasible.

2.3 Selective Catalytic Reduction System

Unit 3 at the IGS is not equipped with a selective catalytic reduction ("SCR") system. Improvement in control of NO_X emissions from Unit 3 through retrofit of an SCR system, either with or without also installing combustion controls designed to reduce NO_X formation, is technically feasible.

[42] *See, e.g.*, 2nd Period Regional Haze Guidance, *supra* note 18, at 11.

2.4 Summary of Control Measure Scenarios

Taking into account all of the identified, technically feasible control measures listed in Sections 2.1 through 2.2 above, the table below lists the scenarios for Unit 3 at the IGS for which further analysis was performed.

Scenario	
Baseline (natural gas, no combustion controls designed to reduce NO_X formation, no add-on controls)	1
Combustion controls designed to reduce NO_X formation	2
Baseline plus SNCR	3
Baseline plus SCR	4
Combustion controls designed to reduce NO_X formation plus SCR	5

3. Analysis Step 2: Emissions Information

As discussed in Section 1.4 above, the second step in the reasonable progress analysis for a particular source involves development of emissions-related information for the baseline scenario and for each control measure under consideration. Emissions information for Scenarios #1 through #5, as listed in Section 2.3 above, is presented in Sections 3.1 through 3.5, respectively. The potential emission reductions for Unit 3 at IGS are somewhat less than would be expected for a baseloaded unit as its projected capacity factor is 27 percent and a significant fraction of its operating time is at less than 50 percent load.

It must be emphasized that the projected emissions for each scenario are nominal projections and are not the emission limits that are achievable with the specified control measures. As with the emissions for the baseline scenario, which are based on long-term observed averages during calendar years 2016 through 2018, the projected emissions for each control scenario are reflective of the most likely projection of actual, long-term average emissions. If any of the control measures under consideration were implemented, the actual emissions would likely be either higher or lower than these projections; if emission limits were imposed based on the use of such control measures, those limits would have to be set at levels that allow for continuous compliance, taking into account averaging period and operational variability.

3.1 Baseline Scenario (Scenario #1) (2028 Projection)

Projected NO_X emissions for Unit 3 at IGS for the 2028 baseline scenario were provided by ADEQ.[43] The unit is assumed to emit zero ammonia (NH_3).

	Units	NO_X	NH_3
UNIT 3	tpy	251	0.0
	lb/MMBtu	0.207	0.000

3.2 Control Scenario #2

This scenario is the same as the baseline scenario, but with retrofit of combustion controls designed to reduce NO_X formation. For purposes of this analysis, this control measure is projected to decrease NO_X emissions by approximately 50 percent, to 0.10 lb/MMBtu.

	Units	NO_X	NH_3
UNIT 3	tpy	121	0.0
	lb/MMBtu	0.100	0.000

[43] *See, e.g.*, e-mail message from Ryan Templeton, ADEQ, to Catherine Schladweiler, TEP, Sept. 24, 2019.

3.3 Control Scenario #3

This scenario is the same as the baseline scenario, but with retrofit of SNCR. For purposes of this analysis, this control measure is projected to decrease NO_X emissions by approximately 20 percent, to 0.17 lb/MMBtu. In addition, the SNCR system is projected to cause NH_3 emissions of 0.002 lb/MMBtu (equivalent to ammonia slip of 5 parts per million by volume, ppmv, in the exhaust).[44]

	Units	NO_X	NH_3
UNIT 3	tpy	206	2
	lb/MMBtu	0.170	0.002

3.4 Control Scenario #4

This scenario is the same as the baseline scenario, but with retrofit of SCR. For purposes of this analysis, this control measure is projected to decrease NO_X emissions by approximately 80 percent, to 0.04 lb/MMBtu. In addition, the SCR system is projected to cause NH_3 emissions of 0.001 lb/MMBtu (equivalent to ammonia slip of 2 parts per million by volume, ppmv, in the exhaust).[45]

	Units	NO_X	NH_3
UNIT 3	tpy	48	1
	lb/MMBtu	0.040	0.001

3.5 Control Scenario #5

This scenario is the same as control scenario #2 (*i.e.*, combustion controls designed to reduce NO_X formation) but with addition of SCR. For purposes of this analysis, this control measure is projected to decrease NO_X emissions by approximately 90 percent relative to the baseline scenario, to 0.02 lb/MMBtu. In addition, the SCR system is projected to cause NH_3 emissions of 0.0008 lb/MMBtu (equivalent to ammonia slip of 2 parts per million by volume, ppmv, in the exhaust).[46]

	Units	NO_X	NH_3
UNIT 3	tpy	24	1
	lb/MMBtu	0.020	0.001

[44] This value is conservative. *See, for example*, U.S. EPA, *Alternative Control Technologies Document: NO_X Emissions from Utility Boilers* (EPA-453/R-94-023), (Mar. 1994), describing typical ammonia slip levels of 10 to 110 ppmv from utility boilers on which urea-based SNCR is used.
[45] *See*, ADEQ BART Technical Support Document, *supra* note 33, at Section XIV.D ("The various SCR vendors typically guarantee ammonia slip of about 2 ppm for systems designed for very high NO_X performance levels.").
[46] *See Id.*

4. Analysis Step 3: Cost of Compliance

As discussed in Section 1.4 above, the third step in the reasonable progress analysis for a particular source involves characterization of the cost of compliance for each control measure under consideration.

4.1 Control Scenario #2 (Combustion Controls)

For purposes of this analysis, the estimated costs associated with retrofitting combustion controls designed to reduce NO_X formation at Unit 3 are based upon the estimates of capital and total annualized costs developed and relied upon by EPA in the Arizona Regional Haze FIP rulemaking.[47] This cost estimate is based on a total capital cost equal to $30 per kW gross generating capacity plus additional costs as shown in the table below.[48] For purposes of this analysis, two adjustments have been made to EPA's cost estimate: First, for purposes of calculating variable operating and maintenance costs, we used the actual capacity factor during the 2016-2018 baseline period, as that is the period that forms the basis for the projected 2028 operating scenario; in addition, for the reasons described in footnote 33 above, rather than the 7.0 percent interest rate used by EPA, RTP has used a conservative interest rate of 5.25 percent.

The estimated total annualized costs, including capital recovery, are approximately $0.36 million per year. The cost effectiveness for NO_X emission reductions with combustion controls is approximately $2,800 per ton. In determining whether the NO_X emission reductions achievable with combustion controls are necessary to make reasonable progress in the second planning period, ADEQ must give consideration not only to the cost effectiveness in terms of dollars per ton of emission reduction but also to the visibility improvement that would result from these emission reductions. At the time of submittal of this report, no modeling of potential visibility improvement due to emissions reductions from the IGS has been performed for the second planning period. However, based on modeling performed for other facilities in Arizona, RTP expects the NO_X emission reductions achievable with combustion controls at Unit 3 at the IGS are much less cost-effective in relation to the small visibility benefits that would be achieved

[47] *See generally* 79 *Fed. Reg.* 9318 (Feb. 18, 2014) and 79 *Fed. Reg.* 52420 (Sept. 3, 2014). The approach taken in this analysis to assessing the cost effectiveness of combustion controls designed to reduce NO_X formation is appropriate because the very small visibility improvements that combustion controls can achieve cannot justify further consideration of this control as necessary for reasonable progress. If further consideration of combustion controls as a NO_X control measure were warranted, additional analysis, including assessment of site-specific factors, would be required.

[48] *See* "Technical Analysis for Arizona and Hawaii Regional Haze FIPs: Task 9: Five-Factor RP Analyses for TEP Springerville, APS Cholla, TEP Sundt, CalPortland Cement and Phoenix Cement Plants," Andover Technology Partners (Oct. 3, 2012), www.regulations.gov/contentStreamer?documentId=EPA-R09-OAR-2013-0588-0006&attachmentNumber=4&contentType=pdf) and underlying calculations at www.regulations.gov/contentStreamer?documentId=EPA-R09-OAR-2013-0588-0007&attachmentNumber=48&contentType=excel12book) (last accessed March 12, 2020).

than in terms of cost per ton of emission reduction. Cost effectiveness in terms of visibility improvement that is more than $70 million per deciview should not be considered reasonable.[49]

Total Capital Investment		
Capacity (MW)	113.6	Section 1.3
TCI ($/kw) =	$30	EPA
TCI ($) =	$3,408,000	
Fixed O&M Costs		
($/kw-yr) =	0.30	EPA
Property Taxes and Insurance	1.20%	of TCI (EPA)
Variable O&M Cost		
($/MWhr) =	0.02	EPA
Gross generation (MWh/yr)	236,883	2016-2018 avg
CRF =	8.20%	Footnote 28
Baseline NO_X		
NO_X Rate (lb/MMBtu)	0.207	Section 3.1
NOx (TPY)	251	Section 3.1
Controlled NO_X		
NO_X Rate (lb/MMBtu)	0.10	Section 3.2
NOx (TPY)	121	Section 3.2
Tons/Year Removed	130	
Annual Costs and Cost Effectiveness		
Annualized capital cost	$279,293	
Fixed O&M	$74,976	Includes taxes & interest
Variable O&M	$4,738	
Total Annual Cost	$359,007	
$/Ton	$2,763	

4.2 Control Scenario #3 (SNCR)

As noted in Section 2.2 above, one of the identified, technically feasible options for further improving control of NO_X emissions from Units 3 at the IGS involves installation of an SNCR

[49] EPA has routinely approved State decisions to reject controls under the Regional Haze rules, even where such controls may reasonably be considered cost effective on a $/ton basis, based on determinations that it is not reasonable to impose substantial control costs to achieve visibility benefits less than one deciview. *See for example*, 83 *Fed. Reg.* 62204 (Nov. 30, 2018), proposing to approve Arkansas' Regional Haze SIP, and specifically approving the decision not to require add-on SO_2 controls at the Independence Steam Electric Station based largely on costs of approximately $70 million per deciview of visibility improvement; *see also* 84 *Fed. Reg.* 51033 (Sept. 27, 2019), finalizing this approval.

system in conjunction with the current configuration (*i.e.*, without combustion controls designed to reduce NO_X formation).

Calculations of capital costs and total annual costs for retrofit of SNCR on Unit 3, conservatively based on EPA's SNCR cost spreadsheet,[50] are provided in Appendix A to this report. As shown in the appendix, the estimated total annual cost is more than $0.5 million.

The projected reduction in NO_X emissions potentially achievable with SNCR is 45 tpy (*i.e.*, the difference between 251 tpy in Scenario #1 and 206 tpy in Scenario #3) based on the assumptions used for purposes of this analysis. The total cost effectiveness of this option relative to the baseline scenario is nearly $12,000 per ton of NO_X emissions reduction. This control option is less effective and more costly than retrofitting combustion controls designed to reduce NO_X formation (*i.e.*, Scenario #2). Because it is an inferior control option, and detailed cost effectiveness analyses are warranted only for those dominant control options that lie on the least-cost curve,[51] the SNCR system retrofit option will be given no further consideration.

4.3 Control Scenario #4 (SCR)

As noted in Section 2.3 above, one of the identified, technically feasible options for further improving control of NO_X emissions from Units 3 at the IGS involves installation of an SCR system in conjunction with the current configuration (*i.e.*, without combustion controls designed to reduce NO_X formation). As explained below, the costs of this control measure far exceed any accepted measure of reasonableness.

Calculations of capital costs and total annual costs for retrofit of SCR on Unit 3, conservatively based on EPA's SCR cost spreadsheet,[52] are provided in Appendix A to this report. As shown in the appendix, the estimated capital cost is nearly $15 million and the estimated total annual cost is nearly $1.5 million.

The projected reduction in NO_X emissions potentially achievable with SCR is 203 tpy (*i.e.*, the difference between 251 tpy in Scenario #1 and 48 tpy in Scenario #4) based on the assumptions used for purposes of this analysis. The total cost effectiveness of this option relative to the baseline scenario is more than $7,000 per ton of NO_X emissions reduction. The incremental cost effectiveness relative to Scenario #2 (*i.e.*, combustion controls designed to reduce NO_X

[50] Available at www.epa.gov/sites/production/files/2019-06/sncrcostmanualspreadsheet_june2019vf.xlsm (last accessed March 4, 2020). Consideration of additional costs based on site-specific factors would be required if a detailed cost-effectiveness analysis were warranted. For the reasons described in this analysis, RTP does not believe such an analysis is needed.

[51] *See*, U.S. EPA, New Source Review Workshop Manual (Draft), (Oct. 1990) at I-B-42 – I-B-43, https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf.

[52] Available at www.epa.gov/sites/production/files/2019-06/scrcostmanualspreadsheet_june-2019vf.xlsm (last accessed March 4, 2020). Consideration of additional costs based on site-specific factors would be required if a detailed cost-effectiveness analysis were warranted. For the reasons described in this analysis, RTP does not believe such an analysis is needed.

formation), as shown in the following table, is more than $15,000 per ton of NO_X emissions reduction. These costs are not reasonable.[53]

Control Scenario #2	Total Annual Cost ($)	$359,007
	NO_X (tpy)	121
Control Scenario #4	Total Annual Cost ($)	$1,452,949
	NO_X (tpy)	48
Incremental Difference	Annual Cost ($)	$1,093,942
	NO_X (tpy)	73
	Cost Effectiveness ($/ton)	$15,043

4.4 Control Scenario #5 (Combustion Controls and SCR)

Another of the identified, technically feasible options for further improving control of NO_X emissions from Unit 3 at the IGS involves retrofitting both combustion controls designed to reduce NO_X formation and an SCR system. As explained below, the costs of this control measure far exceed any accepted measure of reasonableness.

Detailed calculations of capital costs and total annual costs for retrofit of combustion controls designed to reduce NO_X formation on Unit 3 are presented in Section 4.1 above. Calculations of capital costs and total annual costs for retrofit of SCR in this scenario, conservatively based on EPA's SCR cost spreadsheet,[54] are provided in Appendix A to this report. As summarized in the following table, total annual costs associated with this control scenario are approximately $1.8 million.

The projected reduction in NO_X emissions potentially achievable with this control scenario is 227 tpy (*i.e.*, the difference between 251 tpy in Scenario #1 and 24 tpy in Scenario #5) based on the assumptions used for purposes of this analysis. The total cost effectiveness of this option relative to the baseline scenario is nearly $8,000 per ton of NO_X emissions reduction. The incremental cost effectiveness relative to Scenario #2 (*i.e.*, combustion controls designed to reduce NO_X formation), as shown in the following table, is nearly $15,000 per ton of NO_X emissions reduction. These costs are not reasonable.[55]

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[53] EPA has routinely approved State decisions to reject NO_X controls under the Regional Haze rules based on determinations that cost effectiveness values in excess of $2,000 to $3,000 per ton represent unreasonable or unacceptable costs. *See for example*, 77 *Fed. Reg.* 21896 (Apr. 12, 2012), proposing to approve Nevada's Regional Haze SIP with respect to use of SCR for control of NO_X emissions from Unit 3 at the Reid Gardner Generating Station based on average and incremental cost effectiveness $2,183 per ton and $2,756 per ton, respectively; *see also* 77 *Fed. Reg.* 50936 (Aug. 23, 2012), finalizing this approval.

[54] *See supra* note 52.

[55] *See supra* note 53.

Combustion controls designed to reduce NO_X formation	Total Annual Cost ($)	$359,007
SCR	Total Annual Cost ($)	$1,437,241
Total for Control Scenario #5	Annual Cost ($)	$1,796,248
	NO_X reduction (tpy)	227
	Cost Effectiveness ($/ton)	$7,917
Incremental Difference Relative to Control Scenario #2	Annual Cost ($)	$1,437,241
	NO_X tpy	97
	Cost Effectiveness ($/ton)	$14,823

5. Analysis Step 4: Time Necessary for Compliance

As discussed in Section 1.4 above, the fourth step in the analysis involves, for each control measure remaining under consideration, characterization of the time necessary for compliance. The objectives of this step are to determine whether a required control measure can be fully implemented within the second planning period (*i.e.*, by July 31, 2028), because only those measures can be considered by the State in establishing reasonable progress goals for that period,[56] and to establish a compliance schedule.

The time necessary for compliance includes all time needed for full implementation of the control measure, including, first, the time required to develop and implement the regulations; and then, the time needed to implement the control measure in conformance with the final regulations. It is important to note that implementation at an operating facility such as the IGS involves increased planning complexity because scheduling of maintenance outages must be coordinated between the units and with other facilities.

The only technically feasible control measure determined in Step 3 to have costs which potentially could be considered reasonable on a dollars-per-ton-basis is a retrofit of combustion controls at Unit 3 designed to reduce NO_X formation. Based on an initial analysis, TEP and RTP expect that this control measure could be fully implementated before the end of second planning period, assuming timely promulgation of a final SIP in accordance with the current schedule contemplated by ADEQ and EPA. Additional analysis of an appropriate compliance deadline may be warranted as the state and federal processes continue.

If emission limitations reflecting implementation of this control measure are adopted in the Regional Haze SIP for Arizona, the compliance deadline should be the later of (i) July 31, 2028, or (ii) three years after promulgation of a final, non-reviewable SIP approval regulation. In no event should an earlier compliance deadline be adopted, because such earlier deadline is not reasonable in light of the fact that no credit is provided for early reductions under the Regional Haze program. As acknowledged by U.S. EPA,

> Unlike for BART, there is no requirement in the Regional Haze Rule that emission control measures that have been determined to be necessary to make reasonable progress must be installed as expeditiously as practicable or within 5 years of EPA's approval of the SIP revision.[57]

For other control measures identified in Step 1 of the analysis, no characterization or evaluation of the time needed for compliance is necessary, because each such measure has been eliminated from consideration based on plainly unreasonable costs as discussed in Section 4 herein.

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[56] *See generally* 2nd Period Regional Haze Guidance, *supra* note 18, at 41. *See also*, 82 *Fed. Reg.* 3078, 3089 (Jan. 10, 2017).

[57] *See* 2nd Period Regional Haze Guidance, *supra* note 18, at 33.

6. Analysis Step 5: Other Statutory Factors

As discussed in Section 1.4 above, the fifth step in the analysis involves characterization of the the remaining useful life of the emissions units under review and characterization of the energy and non-air quality environmental impacts of each control measure remaining under consideration. These are the remaining two of the four statutory factors. These factors have been considered in the cost-effectiveness analyses presented in Section 4, as discussed below and as recommended in EPA guidance.[58]

For purposes of this analysis, TEP has conservatively assumed that the remaining useful life of Unit 3 at the IGS will be longer than the useful life of any of the control measures evaluated. Accordingly, the expected useful life of each control measure was used in Step 3 of this analysis to calculate its emission reductions, annualized costs, and cost effectiveness. For example, in the evaluation of SNCR summarized in Section 4.1 herein, the expected useful life of an SNCR system is 20 years, so this value was used in calculating the NO_X emission reductions, annualized costs, and cost effectiveness of this control measure.

The collateral energy and environmental impacts associated with each of the control measures evaluated in this analysis also were taken into account in determining costs and cost effectiveness in Step 3. For example, auxiliary power usage associated with installation and operation of an SNCR system was quantified and monetized, and these costs were included in the evaluation of this control measure summarized in Section 4.2 herein.

[58] *See* 2nd Period Regional Haze Guidance, *supra* note 18, at 41-42.

Appendix A

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 113.6 MW

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MWh output? 236,883 MWh

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10.23 MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

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

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	1.05	16.62	9,012	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})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.207	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.17	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.22	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	50	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation: 2625 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2018			
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI
Annual Interest Rate (i)	5.25	Percent		
Fuel ($Cost_{fuel}$)	2.87	$/MMBtu*		
Reagent ($Cost_{reag}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0361	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Fuel Cost ($/MMBtu)	2.87	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,162	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	995,136	MWh	
Estimated Actual Annual MWh Output (Boutput) =		236,883	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	1.02		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.24	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	2085	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	18	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	43.24	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	45.09	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.10		
Atmospheric pressure at 2624.6719160105 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.4	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

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

Reagent Data:

Type of reagent used: Urea

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	192	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	384	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	40.4	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	13,600	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0820

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	13.5	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) $\times ((C_{stored}/C_{inj}) - 1)$ =	0	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.17	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,326,256	in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,776,617	in 2018 dollars
Total Capital Investment (TCI) =	$4,033,735	in 2018 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$1,326,256	in 2018 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$1,776,617	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$202,449	in 2018 dollars
Indirect Annual Costs (IDAC) =	$332,581	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$535,030	in 2018 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.015 x TCI =	$60,506	in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$139,894	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,016	in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$1,033	in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2018 dollars
Direct Annual Cost =		$202,449	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,815	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$330,766	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$332,581	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$535,030	per year in 2018 dollars
NOx Removed =	45	tons/year
Cost Effectiveness =	$11,867	per ton of NOx removed in 2018 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 113.6 MW

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MWhs output? 236,883 MWhs

Enter the net plant heat input rate (NPHR) 10.23 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 2625 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	1.05	9,012
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})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.207	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.04	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	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 utility boilers, the typical equipment life of an SCR is at least 30 years.

Gas temperature at the SCR inlet (T)	650	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

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

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018		
CEPCI for 2018	603.1	Enter the CEPCI value for 2018 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.25	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0361	$/kWh	* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,162	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	995,136	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		236,883	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.02		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.238	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	2085	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.7	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	194.36	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	202.65	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.01		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	538,386	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	121.70	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.10		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.4	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3164	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})	4,423.86	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	561	ft^2

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

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst}$	645	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	25.4	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	76	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/Csol$ =	260	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	35	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	11,700	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0820

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 = Bmw for utility boilers	642.49	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

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

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

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

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

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

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

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

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

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

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

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

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

Total Capital Investment (TCI) =	$14,642,613	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$248,748 in 2018 dollars
Indirect Annual Costs (IDAC) =	$1,204,201 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$1,452,949 in 2018 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$73,213 in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$21,259 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$48,365 in 2018 dollars
Annual Catalyst Replacement Cost =		$105,911 in 2018 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	
Direct Annual Cost =		$248,748 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,507 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,200,694 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,204,201 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,452,949 per year in 2018 dollars
NOx Removed =	203 tons/year
Cost Effectiveness =	$7,170 per ton of NOx removed in 2018 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	113.6	MW
What is the higher heating value (HHV) of the fuel?	1,033	Btu/scf
What is the estimated actual annual MWhs output?	236,883	MWhs
Enter the net plant heat input rate (NPHR)	10.23	MMBtu/MW

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

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	2625	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	1.05	9,012
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})	365 days
Number of days the boiler operates (t_{plant})	365 days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.100 lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.020 lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050

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

Number of SCR reactor chambers (n_{scr})	1
Number of catalyst layers (R_{layer})	3
Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	2 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	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 utility boilers, the typical equipment life of an SCR is at least 30 years.

Gas temperature at the SCR inlet (T)	650 ^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour

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

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

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

Select the reagent used Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018			
CEPCI for 2018	603.1 Enter the CEPCI value for 2018	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index	
Annual Interest Rate (i)	5.25 Percent			
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0361 $/kWh			* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,162	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	995,136	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		236,883	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.02		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.238	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	2085	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	93.00	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	96.96	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	538,386	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	127.25	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.10		
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	13.4	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3164	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})	4,230.85	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	561	ft^2

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

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst}$	645	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	25.4	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	51	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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	36	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/Csol$ =	125	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 =	5,600	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0820

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 = Bmw for utility boilers	642.49	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

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

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

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

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

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

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

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

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

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

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

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

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

Total Capital Investment (TCI) =	$14,642,613	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$233,040	in 2018 dollars
Indirect Annual Costs (IDAC) =	$1,204,201	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$1,437,241	in 2018 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$73,213	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$10,172	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$48,365	in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$101,290	in 2018 dollars
Direct Annual Cost =		$233,040	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,507	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,200,694	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,204,201	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,437,241	per year in 2018 dollars
NOx Removed =	97	tons/year
Cost Effectiveness =	$14,823	per ton of NOx removed in 2018 dollars