United States Steel Corporation
Mon Valley Works

Kurt Barshick
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U. S. Steel Mon Valley Works

December 22, 2022

Ms. JoAnn Truchan, P.E.
Program Manager, Permitting – Air Quality
Allegheny County Health Department
301 39th Street, Bldg. No. 7
Pittsburgh, PA 15201-1891

Dear Ms. Truchan:

RE: United States Steel Corporation – Mon Valley Works – Irvin Plant
Re: Reasonably Available Control Technology (RACT) Evaluation Request

On November 12, 2022, the Pennsylvania Department of Environmental Protection (PADEP), finalized new Reasonably Available Control Technology (RACT) regulations, published at 25 Pa. Code Chapter 129, which include RACT requirements and limits for major sources of NOx and VOC. Allegheny County Health Department (ACHD) has incorporated the RACT III regulation finalized by PADEP per ACHD Rules and Regulations, Article XXI Air Pollution Control §2105.08. The United States Steel Corporation (U. S. Steel) – Mon Valley Works – Irvin Plant is subject to certain provisions of this regulation including presumptive RACT, alternative RACT, associated monitoring, recordkeeping, and reporting.

The attached document is submitted pursuant to §§129.111, 129.112, 129.114, and 129.115(a) (as these provisions are incorporated into Article XXI).

If you have any questions pertaining to this RACT submittal, please contact Nicole Heinichen at (412) 675-7382 or nlheinichen@uss.com.

Based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Sincerely,

Kurt Barshick

cc: M. Jeffrey
N. Heinichen

PENNSYLVANIA RACT III

NOTIFICATION OF COMPLIANCE STATUS & ALTERNATIVE RACT PROPOSAL

United States Steel Corporation / Irvin Plant

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1. INTRODUCTION

United States Steel Corporation (U. S. Steel) owns and operates a secondary steel processing facility in West Mifflin, Pennsylvania known as the Irvin Plant. The Irvin Plant receives steel slabs and performs several finishing processes on the steel slabs. The finishing processes include hot rolling of slabs, cold rolling of steel strip, continuous pickling, annealing, and galvanizing (zinc coating of steel strip). Through these operations, the Irvin Plant produces carbon steel strip in the form of finished steel coils for use in many industrial and commercial products. The plant operates under federally enforceable Title V Operating Permit (TVOP) No. 0050-OP16c. The Irvin Plant is considered a major source of nitrogen oxides (NO_x) and volatile organic compounds (VOC).

On November 12, 2022, the Pennsylvania Department of Environmental Protection (PADEP), finalized new Reasonably Available Control Technology (RACT) regulations, published at 25 Pa. Code Chapter 129, which include RACT requirements and limits for major sources of NO_x and VOC (referred to as "RACT III"). Allegheny County Health Department (ACHD) has incorporated the RACT III regulation finalized by PADEP per ACHD Rules and Regulations, Article XXI Air Pollution Control §2105.08. The Irvin Plant is subject to certain provisions of this regulation including presumptive RACT, alternative RACT, and associated monitoring, recordkeeping, and reporting.

This document is intended to meet the requirement to submit a written notification of compliance status (NOCS) per §129.115(a). This document also contains U. S. Steel's proposal for alternative RACT requirements/limits per §129.114(d) for applicable sources.

1.1 Facility Information

The Mon Valley Works is an integrated steelmaking operation that includes four separate facilities: Clairton Plant, Edgar Thomson Plant, Irvin Plant and Fairless Plant. The Irvin Plant is a secondary steel processing facility that produces finished steel. The Irvin Plant rolls and treats steel slabs produced at the nearby Edgar Thomson Plant to meet customer specifications. Major sheet products manufactured at the Irvin Plant include hot-rolled, cold-rolled and coated sheet in addition to products for special applications.

The facility is composed of an 80" hot strip mill, 64" and 84" continuous hydrochloric acid pickle lines, a cold reduction mill, HPH annealing furnaces, open coil annealing furnaces, a continuous annealing furnace, Continuous Galvanizing Line No.1, Continuous Galvanizing and Aluminum Coating Line No. 2, and four coke oven gas flares. There are four boilers at the Irvin Plant which are used to generate steam and heat for the plant. The primary fuels for the boilers are Coke Oven Gas (COG) and Natural Gas (NG).

1.2 Summary of RACT Requirements

25 Pa Code 129.111 through 129.115 (RACT III) applies to existing major facilities of NO_X and/or VOC in Pennsylvania. These provisions have been adopted by ACHD per Article XXI §2105.08. Existing major facilities subject to RACT III are those facilities which are a major source of NO_X and/or VOC that commenced operation on or before August 3, 2018. The Irvin Plant is located in Allegheny County where the NO_X and VOC major source thresholds are 100 and 50 tons per year (tpy), respectively, on a potential to emit (PTE) basis. As a major source of both pollutants, the Irvin Plant is subject to both the NO_X and VOC RACT requirements under RACT III.

Per 25 PA Code 129.111(c), sources (i.e., emissions units) with a PTE less than 1.0 tpy of NO_X and VOC are exempt from RACT III requirements. Table 1-1 identifies the sources for which U. S. Steel has claimed this exemption.

RACT is defined in Article XXI §2101.20 as

> *"any air pollution control equipment, process modifications, operating and maintenance standards, or other apparatus or techniques which may reduce emissions and which the Department determines is available for use by the source affected in consideration of the necessity for obtaining the emission reductions, the social and economic impact of such reductions, and the availability of alternative means of providing for the attainment and maintenance of the NAAQS's."*

RACT III also does not apply to sources subject to, or for which a requirement or emission limitation has been established under, existing VOC standards in Article XXI (e.g., §2105.15, etc.)[1]. The solvents parts cleaning operations (F002 in the current permit) are subject to §2105.15 and §2105.82, as outlined in the permit. Fuel and other hydrocarbon storage tanks (e.g., containing rolling solutions) at the site already are potentially subject to VOC requirements depending on their size and the vapor pressure of its contents (e.g., §2105.12a). As such, these operations are not subject to RACT III as per 25 Pa Code 129.111(a).

For applicable sources subject to the RACT III regulations, there are three options for compliance:

- Compliance Option 1 (25 PA Code 129.112): Presumptive RACT;
- Compliance Option 2 (25 PA Code 129.113): System-Wide Averaging (not discussed further in this document since not applicable to the site); or
- Compliance Option 3 (25 PA Code 129.114): Alternative (Case-by-Case) RACT Proposal.

A matrix of the proposed RACT III compliance options for the Irvin Plant sources is depicted in the following table. All the sources are located at the steel processing area, with exception of the flares.

Table 1-1. RACT III Applicability for Irvin Plant

Source ID	Source Description	NO_X RACT Status	VOC RACT Status
P001	80-Inch Hot Strip Mill Reheat Furnace No. 1 (140 MMBtu/hr; firing COG/NG)	Alternative Proposal	Presumptive
P002	80-Inch Hot Strip Mill Reheat Furnace No. 2 (140 MMBtu/hr; firing COG/NG)	Alternative Proposal	Presumptive
P003	80-Inch Hot Strip Mill Reheat Furnace No. 3 (140 MMBtu/hr; firing COG/NG)	Alternative Proposal	Presumptive
P004	80-Inch Hot Strip Mill Reheat Furnace No. 4 (140 MMBtu/hr; firing COG/NG)	Alternative Proposal	Presumptive
P005	80-Inch Hot Strip Mill	Alternative Proposal	Presumptive

[1] A complete listing of 25 Pa Code and Article XXI references for such VOC regulations are found on ACHD's website (98-SIP-RACT-III-Regulation.pdf (alleghenycounty.us)).

Source ID	Source Description	NOx RACT Status	VOC RACT Status
	Reheat Furnace No. 5 (140 MMBtu/hr; firing COG/NG)		
P008	Cold Reduction Mill Mill Stands No. 1 to No. 5	Not Applicable (N/A)	Alternative Proposal
P009	HPH Batch Annealing Furnaces (31 individual furnaces; each 4.9 MMBtu/hr; firing COG and NG)	Presumptive	Presumptive
P010	Furnaces No. 1 to No. 9 (7.2 MMBtu/hr each; firing COG and NG)	Presumptive	Presumptive
P010	Furnaces No. 10 to No. 13 (9.0 MMBtu/hr each; firing COG and NG)	Presumptive	Presumptive
P010	Furnace No. 14 (5.4 MMBtu/hr; firing COG and NG)	Presumptive	Presumptive
P010	Furnace No. 15 to No. 16 (7.47 MMBtu/hr each; firing COG and NG)	Presumptive	Presumptive
P011	Continuous Annealing (45 MMBtu/hr; firing COG and NG)	Alternative Proposal	Presumptive
P012	No. 1 Continuous Galvanizing Preheat Furnace (50 MMBtu/hr; firing NG)	Presumptive	Presumptive
P013	No. 2 Continuous Galvanizing Preheat Furnace (18 MMBtu/hr; firing NG)	Presumptive	Presumptive
P015	COG Flares No. 1 through No. 3 (6.75 MMSCFD, each)	Presumptive	Presumptive
P015	Peachtree COG Flare (Line A and B) (6.75 MMSCFD)	Presumptive	Presumptive
P016	HSM Roughing and Finishing Mill Oil Usage	N/A	Alternative Proposal
B001	Boiler No. 1 (Nebraska boiler; 79.8 MMBtu/hr; firing COG and NG)	Alternative Proposal	Presumptive
B002	Boiler No. 2 (Cleaver Brooks; Model DL-76; 84.6 MMBtu/hr; firing COG and NG)	Alternative Proposal	Presumptive
B003	Boiler No. 3 (Nebraska boiler; 41.6 MMBtu/hr; firing COG and NG)	Presumptive	Presumptive
B004	Boiler No. 4	Presumptive	Presumptive

Source ID	Source Description	NO_x RACT Status	VOC RACT Status
	(Nebraska boiler; 41.6 MMBtu/hr; firing COG and NG)		
N/A	Paints, Thinners, Inks & Solvents	N/A	Exempt
N/A	Fuel/Other HC Storage Tanks	N/A	Exempt
N/A	Misc. Natural Gas Combustion	Presumptive	Presumptive

1.2.1 Presumptive RACT

The first compliance option for non-exempt sources is to comply with presumptive RACT limits as outlined in §129.112. Under these RACT regulations, presumptive RACT limits are included for the following categories of sources that are potentially applicable to operations at the Irvin Plant:

- Combustion units: §129.112(b)(1) and §129.112(c)(4);
- Boilers: §129.112(b)(1) and §129.112(c)(4);
- Process heaters: §129.112(b)(1) and §129.112(c)(4);
- Incinerators, thermal oxidizers or catalytic oxidizers or flares used primarily for air pollution control: §129.112(c)(8);
- Combustion sources: §129.112(d) [for VOC emissions] and §129.112(k); and
- Other sources not regulated elsewhere in 25 Pa Code 129 with potential emissions less than 5 tpy of NO_x and 2.7 tpy of VOC: §129.112(c)(1).

1.2.1.1 Presumptive Sources – §129.112(b)(1)

RACT III includes presumptive requirements for combustion units and process heaters under §129.112(b)(1). The Irvin Plant consists of two (2) emission sources that are classified as combustion units or process heaters with heat input ratings greater than 20 MMBtu/hr and less than 50 MMBtu/hr. These sources, listed in the following table, are subject to presumptive RACT III requirements under §129.112(b)(1) to perform biennial tune-ups in accordance with the procedures of 40 CFR 63.11223.

Table 1-2. Presumptive - Combustion Units & Process Heaters (20-50 MMBtu/hr)

Source ID	Source Description	Unit Rating (MMBtu/hr)
B003	Boiler No. 3	41.6 MMBtu/hr
B004	Boiler No. 4	41.6 MMBtu/hr

1.2.1.1 Presumptive Sources – §129.112(c)(1) &(c)(2)

RACT III includes presumptive requirements for a NO_x air emissions source that has a potential to emit less than 5 tpy NO_x (§129.112(c)(1)) and/or 2.7 tpy of VOC ((§129.112(c)(2)). Several emissions sources at the Irvin Plant do not fall under another presumptive source category and have a PTE meeting the criteria for this presumptive category.

The corresponding presumptive RACT III requirement under §129.112(c) is to install, maintain and operate in accordance with the manufacturer's specifications and with good operating practices. The sources subject to these requirements at the Irvin Plant are listed below.

Table 1-3. Presumptive – NO_x PTE <5 tpy and/or VOC <2.7 tpy

Source ID	Source Description	NOx PTE (tpy)	VOC PTE (tpy)
P009	HPH Batch Annealing Furnaces (31 individual furnaces)	3.22 (per furnace)	N/A – Presumptive per 129.112(d)
B001	Boiler No. 1	N/A – See Alternative RACT Proposal	2.2
B002	Boiler No. 2	N/A – See Alternative RACT Proposal	2.4

1.2.1.2 Presumptive Sources – §129.112(c)(4)

RACT III includes presumptive requirements for boilers and other combustion sources with an individual gross heat input less than 20 MMBtu/hr under §129.112(c)(4). Several emissions sources at the plant meet the definition of a combustion source and have a gross heat input less than 20 MMBtu/hr.

The presumptive RACT III requirement under §129.112(c) is to install, maintain and operate in accordance with the manufacturer's specifications and with good operating practices. The sources subject to these requirements at the Irvin Plant are listed below.

Table 1-4. Presumptive – Combustion Sources (<20 MMBtu/hr)

Source ID	Source Description	Unit Rating (MMBtu/hr)
P010	Annealing Furnaces No. 1 to No. 9	7.2 (each)
P010	Annealing Furnaces No. 10 to No. 13	9 (each)
P010	Annealing Furnace No. 14	5.4
P010	Annealing Furnaces No. 15 & No. 16	7.47 (each)
P012	No. 1 Continuous Galvanizing Galvanneal Furnace	18
P013	No. 2 Continuous Galvanizing Galvalum Furnace	18
N/A	Misc. Natural Gas Combustion (e.g., space heaters)	Each one <20 MMBtu/hr

1.2.1.1 Presumptive Sources – §129.112(c)(8)

RACT III includes presumptive requirements for incinerators, thermal oxidizers or catalytic oxidizers or flares used primarily for air pollution control under §129.112(c)(8). The presumptive RACT III requirement under §129.112(c) is to install, maintain and operate in accordance with the manufacturer's specifications and with good operating practices. The sources subject to these requirements at the Irvin Plant are listed below.

Table 1-5. Presumptive – Flares

Source ID	Source Description
P015	COG Flares No. 1 through No. 3
P015	Peachtree COG Flare (Line A and B)

1.2.1.1 Presumptive Sources – §129.112(d)

RACT III includes presumptive requirements with respect to VOC emissions for combustion units and combustion sources (amongst other source types) per §129.112(d) as follows:

> *Except as specified in subsection (c), the owner and operator of a combustion unit, brick kiln, cement kiln, lime kiln, glass melting furnace or combustion source located at a major VOC emitting facility subject to § 129.111 shall install, maintain and operate the source in accordance with the manufacturer's specifications and with good operating practices for the control of the VOC emissions from the combustion unit, brick kiln, cement kiln, lime kiln, glass melting furnace or combustion source.*

As it relates to the Irvin Plant, this provision applies to VOC emissions from the various furnaces as they are classified as "combustion sources" in the rule. These furnaces include Source IDs, P001 through P005, P009, P010, P011, P012 and P013.

1.2.1.2 Presumptive Sources – §129.112(k)

RACT III includes presumptive requirements for direct-fired heaters, furnaces, ovens, or other combustion sources with a rated heat input equal to or greater than 20 MMBtu/hr. This requirement limits NO_X emissions to less than 0.10 lb/MMBtu per §129.112(k). This limit is applicable to the Hot Strip Mill reheat furnaces (P001 – P005), continuous annealing furnace (P011) and the No. 1 continuous galvanizing preheat furnace (P012). Source ID P012 already has a lb/hr NO_X limit that satisfies the RACT emission limit, and the permit already states as such. U. S. Steel will track fuel usage to maintain compliance with that existing limitation. Source IDs P001 through P005 and P011 are not able to meet this emissions limit due to multi-fuel capabilities (e.g., use of COG as a fuel) and therefore is subject to alternative RACT proposal requirements.

Table 1-6. Presumptive Sources – Combustion Sources >= 20 MMBtu/hr

Source ID	Source Description	Unit Rating (MMBtu/hr)
P001 – P005	80-Inch Hot Strip Mill Reheat Furnaces No. 1 – No. 5	140 (each)
P011	Continuous Annealing	45
P012	No. 1 Continuous Galvanizing Preheat Furnace	50

1.2.2 Alternative (Case-by-Case) RACT Proposal

For sources which are unable to meet presumptive RACT III limits, unable to participate in system-wide averaging, and/or which do not qualify for one of the source categories that have presumptive RACT limits, Compliance Option 3 remains. Under Compliance Option 3, facilities must propose an alternative RACT requirement or emission limitation (i.e., case-by-case RACT) in accordance with §129.114(d).

The sources at the Irvin Plant which require alternative RACT proposals, along with the qualifying criteria, are summarized in the following table.

Table 1-7. Alternative (Case-by-Case) RACT III

Source ID	Source Description	Status
P001	80-Inch Hot Strip Mill Reheat Furnace No. 1	No Presumptive Category Based on Fuels (NO_X > 5 tpy)
P002	80-Inch Hot Strip Mill Reheat Furnace No. 2	No Presumptive Category Based on Fuels (NO_X > 5 tpy)
P003	80-Inch Hot Strip Mill Reheat Furnace No. 3	No Presumptive Category Based on Fuels (NO_X > 5 tpy)
P004	80-Inch Hot Strip Mill Reheat Furnace No. 4	No Presumptive Category Based on Fuels (NO_X > 5 tpy)
P005	80-Inch Hot Strip Mill Reheat Furnace No. 5	No Presumptive Category Based on Fuels (NO_X > 5 tpy)
P008	Cold Reduction Mill (Mill Stands No. 1 to No. 5)	No Presumptive Category (VOC > 2.7 tpy)
P011	Continuous Annealing	Cannot Meet Presumptive Limit for NO_x
B001	Boiler No. 1	No Presumptive Category Based on Fuels (NO_X > 5 tpy)
B002	Boiler No. 2	No Presumptive Category Based on Fuels (NO_X > 5 tpy)
P016	HSM, Roughing and Finishing Mill Oil Usage	No Presumptive Category (VOC > 2.7 tpy)

Per 25 Pa Code 129.114, the case-by-case RACT proposal must include each of the elements required under 25 Pa Code 129.92(a)(1)-(5), (7)-(10) and (b). For sources in Allegheny County this translates to Article XXI §2105.06a, b and c. For emissions sources that were subject to alternative RACT proposals under RACT II and for which no new pollutant-specific air pollution control technology or technique is determined to be available, the facility may submit an analysis demonstrating that alternative RACT II conclusions are sufficient to satisfy RACT III. There is an additional caveat that the cost-effectiveness must have previously been calculated consistent with the EPA Air Pollution Control Cost Manual (6th Edition)[2] and remains equal to or greater than $7,500 per ton of NO_X emissions reduced or $12,000 per ton of VOC emissions reduced. The following sections of this document outline the conclusions of this assessment and summarize the alternative RACT III proposals.

[2] EPA/452/B-02-001, January 2002, as amended.

2. ALTERNATIVE RACT SOURCES

As noted in Section 1, there are several sources at the Irvin Plant that require alternative RACT proposals. These sources can be consolidated based on common emissions and/or operational characterizations as summarized in the following table.

Table 2-1. Source Types for Alternative RACT

Source Type	Source ID & Description	RACT-Affected Pollutants
Combustion Sources (Furnaces)	P001: 80" HSM Reheat Furnace No. 1 P002: 80" HSM Reheat Furnace No. 2 P003: 80" HSM Reheat Furnace No. 3 P004: 80" HSM Reheat Furnace No. 4 P005: 80" HSM Reheat Furnace No. 5 P011: Continuous Annealing Furnace	NO_X
Combustion Units (Boilers)	B001: Boiler No. 1 B002: Boiler No. 2	NO_x
Cold Reduction Mill	P008: Mill Stands No. 1 to No. 5	VOC
HSM Roughing and Finishing Mill, Oil Usage	P016: Roughing and Finishing Mill Oil Usage	VOC

3. ALTERNATIVE RACT ANALYSIS

This section of the report provides the detailed proposed alternative RACT III requirements for sources at the Irvin Plant.

3.1 Top-Down Methodology

Case-by-case RACT determinations are traditionally based on a top-down methodology. PADEP has outlined the required elements of a RACT analysis and determination in 25 Pa Code 129.92(b) as referenced in 25 Pa Code 129.114(d)(3). ACHD has historically followed these same procedures under the framework of §2105.06(b)(2). Presented below are the five (5) basic steps of the top-down RACT review.

3.1.1 Step 1: Identify All Control Technologies

Under Step 1, all available control technologies are identified for each emission unit in question. The following methods may be used to identify potential technologies:

- Researching U.S. EPA's RACT/BACT (Best Available Control Technology)/LAER (Lowest Achievable Emission Rate) Clearinghouse (RBLC) database;
- Surveying regulatory agencies;
- Drawing from previous engineering experience;
- Surveying air pollution control equipment vendors; and
- Surveying available literature.

Once identified, the control technologies are ranked in descending order of expected control effectiveness.

3.1.2 Step 2: Eliminate Technically Infeasible Options

After control technologies are identified under Step 1, an analysis is conducted to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that prohibit the implementation of the control technology or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits, such as a New Source Performance Standard (NSPS) or National Emission Standard for Hazardous Air Pollutants (NESHAP).

3.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

In Step 3, remaining control technology options are ranked based on their control effectiveness, from highest to lowest control efficiency. This list must identify, at a minimum, the baseline emissions of VOC and NO_X before implementation of each control option, the estimated reduction potential or control efficiency of each control option, the estimated emissions after the application of each control option and the economic impacts.

3.1.4 Step 4: Evaluate Most Effective Controls and Document Results

Beginning with the highest-ranked control technology option from Step 3, detailed economic, energy, and environmental impact evaluations are performed in Step 4. If a control option is determined to be economically feasible without adverse energy or environmental impacts, it is not necessary to evaluate the remaining options with lower control efficiencies.

The economic evaluation centers on the cost effectiveness of the control option. Costs of installing and operating control technologies are estimated and annualized following the methodologies outlined in the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (CCM) and other industry resources.

3.1.5 Step 5: Select RACT

Using the result of the prior steps to determine the appropriate control technology, the final step is to determine the emission limit that represents the RACT limit.

3.2 NO_X RACT Assessment for Combustion Units - Furnaces

The Irvin Plant operations include natural gas-fired combustion sources (i.e., direct-fired units) that are not able to meet presumptive NO_X limits, have multi-fuel capabilities, and/or have potential NO_X emissions greater than 5 tpy. These sources can be grouped by their similar design and function as follows:

- Hot Strip Mill Reheat Furnaces (P001 to P005)
- Continuous Annealing Furnace (P011)

When considering NO_x emissions from combustion processes (e.g., boilers, furnaces, etc.), there are three types of chemical kinetic processes. The NO_X emissions from these chemical mechanisms are referred to as: (1) thermal NO_X; (2) fuel NO_X; and (3) prompt NO_X.

Thermal NO_X is generated by the oxidation of molecular nitrogen (N_2) in the combustion air as it passes through the flame in the burners of the boilers or furnaces. This reaction requires high temperatures, hence the name thermal NO_X. The formation of nitrogen oxide (NO) from oxygen (O_2) and N_2 in air at high temperatures is described by the well-known Zeldovich mechanism. Fuel NO_X is the result of the conversion of nitrogen compounds contained in fuels to NO_X during fuel combustion. Prompt NO_X, which forms from the rapid reaction of atmospheric nitrogen with hydrocarbon radicals is insignificant compared to the overall quantity of thermal and fuel NO_X generated in combustion units/sources.

3.2.1 Step 1: Identify All Control Technologies for NO_X

Step 1 in a top-down analysis is to identify all available control technologies. The evaluation of potential controls for NO_X emissions from furnaces include both an investigation of end-of-pipe (post-combustion methods) and combustion modifications/optimization that reduce the formation of thermal NO_X. The basic complicating factor in efforts to reduce thermal NO_X from the steel industry is the fundamental need for high temperatures in order to work the materials (i.e., steel). Table 3-1 contains a list of the various technologies that have been identified as potentially applicable for the control of NO_X emissions from steel processing furnaces.

Table 3-1. Potentially Available NOx Control Technologies for Furnaces

Potentially Applicable NO_X Control Technologies
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)
Low NO_X or Ultra Low NO_X Burners (LNB or ULNB)
Good Combustion Practices

3.2.2 Review of Potentially Applicable NO_X Control Technologies

The following section provides a discussion of each potentially applicable technology identified above as it might be applied to the furnaces at the Irvin Plant. There are no new pollutant specific air cleaning devices or technologies since the RACT II evaluation.

3.2.2.1 Selective Non-Catalytic Reduction (SNCR)

SNCR uses ammonia (NH3) or a urea solution [$CO(NH_2)_2$], injected into the gas stream, to chemically reduce NO_X to form N2 and water. High temperatures, optimally between 1,600 to 2,400°F, promote the reaction via the following equation:

$$CO(NH_2)_2 + 2\ NO + \tfrac{1}{2}\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$
$$4\ NH_3 + 6NO \rightarrow 5\ N_2 + 6\ H_2O$$

At temperatures below the optimal range, unreacted ammonia can pass through the SNCR and be emitted from the stack (known as "ammonia slip"). At temperatures above the range, ammonia may be combusted, generating additional NO_X. In addition, an effective mixing of gases and entrainment of the reductant into the exhaust gases at the injection point is a critical factor in ensuring an efficient reaction. SNCR is being employed on various types of combustion sources in a wide range of sizes, including industrial boilers, electric utility steam generators, thermal incinerators, cement kilns, and industrial process furnaces in various sectors.[3] SNCR is not suitable for sources where the residence time is too short (reducing conversion of reactants), temperatures or NO_X concentrations are too low (slowing reaction kinetics), the reagent would contaminate the product, or no suitable location exists for installing reagent injection ports. Expected removal efficiencies for SNCR range from 25 to 65 percent, and are dependent on many factors, including the reagent type, injection rate, pre-control NO_X concentration as well as CO and O_2 concentrations, temperature and residence time.[4]

3.2.2.2 Selective Catalytic Reduction (SCR)

Like SNCR, SCR is also a post-combustion NO_X control technology which removes NO_X from flue gas based on the chemical reaction of a NO_X reducing agent (typically ammonia), however, in the case of SCR this takes place using a metal-based catalyst. An ammonia or urea reagent is injected into the exhaust gas and the reaction of NO_X and oxygen occurs on the surface of a catalyst which lowers the activation energy required for NO_X decomposition into nitrogen gas and water vapor. Reactor design, operating temperature, sulfur content of the fuel, catalyst de-activation due to aging, ammonia slip emissions, and the ammonia

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[3] Air Pollution Control Cost Manual, Section 4.2, Chapter 1, Selective Non-Catalytic Reduction, NO_X Control, EPA Form 2220-1.(rev. 4-77), Page 1-1.

[4] Air Pollution Control Cost Manual, Section 4.2, Chapter 1, Selective Non-Catalytic Reduction, NO_X Control, EPA Form 2220-1.(rev. 4-77), Page 1-2.

injection system design are all important technical factors for effective SCR operation. Generally, SCR can achieve higher control efficiencies and be applied to a broader and lower range of exhaust temperatures relative to SNCR. However, this is accompanied by significantly higher capital and operating costs. Another primary disadvantage of an SCR system is that particles from the catalyst may become entrained in the exhaust stream and contribute to increased particulate matter emissions. In addition, ammonia slip reacts with the sulfur in the fuel creating ammonia bisulfates that become particulate matter.

The primary chemical reactions for an SCR unit can be expressed as follows:

$$4\ NH_3 + 4\ NO + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$4\ NH_3 + 2\ NO_2 + 2\ O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

The optimum temperature range for the majority of commercial SCR system catalysts is 480 to 800˚F; operation outside the optimum temperature range can result in increased ammonia slip or increased NO_X emissions. Application of SCR technology can result in removal efficiencies of over 90 percent depending on the source conditions.

3.2.2.3 Low NO_X Burners (LNBs)[5]

The principle of all LNBs is the same: step-wise or staged combustion and localized exhaust gas recirculation at the flame is employed. LNBs are designed to control fuel and air mixing to create larger and more branched flames. Peak flame temperatures are reduced and the flame structure reduces oxygen supply to the hottest part of the flame, resulting in less NO_X formation. LNBs eliminate the need for steam or water injection, which was formerly the traditional method of NO_X control.

LNB retrofits on existing units must carefully consider furnace geometry, as the LNB flame diameters and lengths are typically larger and can impinge on furnace walls which may lead to reduced control efficiencies.

3.2.2.4 Good Combustion Practices/Proper Furnace Operation/Minimize Excess Air

The formation of NO_X is minimized by proper combustion unit design and operation. Generally, emissions are minimized when the operating temperatures are kept at the lower end of the desired range. The controlled distribution of air at the air and fuel injection zones can also help minimize NO_x formation. Ideally, maintaining a low-oxygen condition near fuel injection points approaches an off-stoichiometric staged combustion process. A certain amount of air is required to provide sufficient oxygen to burn all of the fuel introduced to the furnaces. However, excess air contributes to increased NO_X emissions through increasing the amount of air that must be heated (i.e., decreasing fuel efficiency and resulting in higher NO_X emissions) and providing more oxygen in the combustion zone which can in turn lead to greater amounts of thermal NO_X formation. By minimizing the amount of air used in the combustion process while maintaining proper furnace operation, the formation of NO_X can be reduced.

3.2.3 Step 2: Eliminate Technically Infeasible Options for NO_X Control

Step 2 in a RACT top-down analysis is to eliminate the control options identified in Step 1 which are technically infeasible. The remaining technologies are then carried into Step 3.

[5] This analysis includes low-NO_X burners (LNBs) and ultra-low NO_X burners (ULNBs). Since the operating principles and constraints are the same, the analysis has been grouped.

3.2.3.1 Selective Non-Catalytic Reduction (SNCR)

SNCR requires a relatively high and very specific/narrow temperature range (generally between 1,550 °F and 1,950 °F), uncontrolled NO_X emissions above 200 ppm, and residence times of at least 1 second to be effective. Exhaust temperatures for the Irvin Plant hot strip mill reheat furnaces (P001 – P005) average below 500 °F, which is well below the effective SNCR threshold operating temperature range of 1,550 – 1,950 °F. In addition, the uncontrolled concentrations of NO_X in the exhaust gas from these furnaces averages around 75 ppm, which is well below the effective SNCR threshold of > 200 ppm.[6] Finally, the hot strip mill furnaces are direct-fired units, where the injection of reagent (if there was even adequate space to accomplish injection) could contact the steel product and compromise product quality.

A review of EPA's RBLC database shows that SNCR has not been commercially demonstrated on any steel reheat furnaces in the U.S. The significant technical challenges posed by the installation of SNCR for treating the furnaces' exhaust streams make the control technology **not technically feasible** for RACT for the reheat furnaces.

Annealing furnaces typically operate in the range of 1,000 – 1,300 °F, and the annealing furnaces at Irvin Plant have exhaust temperatures around 465 °F. This would require the addition of supplemental heat to achieve optimal operating conditions for effective use of SNCR. Despite technical concerns and a lack of demonstrated application, U. S. Steel has carried forward this technology for the continuous annealing furnace.

3.2.3.2 Selective Catalytic Reduction (SCR)

A review of EPA's RBLC database showed two entries citing use of SCR for NO_X control on steel industry furnaces.[7] The first case involved a pickling line furnace where SCR is used in conjunction with a caustic scrubber. As this source is materially different from the Irvin Plant's reheat and continuous annealing furnaces, this is not considered a comparable application of the technology. In the second case, the facility was never constructed, and as such SCR has not been successfully demonstrated in practice on a similar source. The SCR process is temperature sensitive, such that any exhaust gas temperature fluctuations will result in reduced removal efficiency and will upset the NH_3/NO_X molar ratio. The installation of necessary components of the ammonia injection system and catalyst would also require extensive structural modifications to the furnaces and nearby structures. SCR requires an optimum temperature range of 480 to 800°F and fairly constant temperatures, or NO_X removal efficiency will decrease.[8] Below this temperature range, the reaction rate drops sharply and effective reduction of NO_x is no longer feasible. Above this temperature, conventional reduction catalysts break down and are unable to perform their desired functions. As noted in the previous SNCR discussion, the exhaust gas temperatures from the Irvin Plant's reheat furnaces are below the optimum SCR operating range, and these furnaces are all direct-fired sources, where there is risk of product contamination from contact with the reagent.

For the various reasons described above, SCR is considered to be **not technically feasible** for controlling NO_X emissions from the hot strip mill reheat furnaces and the continuous annealing furnace. Further evaluation of the technology is not required.

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[6] Hot strip mill reheat furnace exhaust gas temperatures and NO_X emissions data for Irvin Plant was collected during compliance testing on these units conducted in 2021.

[7] RBLC ID No. AL-0230 and No. OH-0315.

[8] U.S. EPA, Technology Transfer Network, Clean Air Technology Center. "Air Pollution Control Technology Fact Sheet – Selective Catalytic Reduction." File number EPA-452/F-03-032. July 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf (26 Nov. 2014).

3.2.3.3 Low NO_X Burners (LNBs)

A review of the RBLC for steel industry furnace permits shows multiple permits in which LNB was determined to be BACT. The use of LNBs in direct-fired furnaces is widely used and can provide significant NO_x reductions. Burner flame properties are critical to the quality control and steel manufacturing process, which could present some unique design and cost challenges when retrofitting the furnaces at the Irvin Plant.

LNB technology is considered to be **technically feasible** for the hot strip mill reheat furnaces and the continuous annealing furnace at the Irvin Plant, and therefore the cost-effectiveness is further considered in this proposal.

3.2.3.4 Good Combustion Practices/Proper Furnace Operation/Minimize Excess Air

As noted previously, the formation of NO_X can be minimized by proper furnace operation. Generally, emissions are minimized when the furnace temperature is kept at the lower end of the desired range and when the distribution of air at the air and fuel injection zones is controlled. A high thermal efficiency would lead to less consumption of heat and fuel and would produce less NO_X emissions. General improvement in thermal efficiency is one design method of reducing NO_X formation, since less fuel is used.

U. S. Steel currently maintains and operates the hot strip mill reheat furnaces and the continuous annealing furnace at the Irvin Plant in accordance with good combustion practices and proper furnace design as demonstrated through annual tune-up activities. These are **technically feasible** methods for controlling NO_X emissions from the furnaces.

3.2.4 Step 3: Rank Remaining Control Technologies by Control Effectiveness

In Step 3, the remaining control technology options are ranked based on their control effectiveness, from highest to lowest control efficiency. There are three (3) control technologies that are considered technically feasible: SNCR, LNB, and Good Combustion Practices. The ranking for the control technologies are as follows:

1. SNCR (Continuous Annealing Furnace P011 only)
2. LNB
3. Good Combustion Practices

3.2.5 Step 4: Evaluate Most Effective Controls and Document Results

U. S. Steel has evaluated the cost for installing SNCR on the continuous annealing furnace, as well as the cost for retrofitting existing burners with low-NO_X or ultra-low-NO_X burners for the six furnaces in question. The costs shown have been conservatively calculated using potential-to-emit (rather than actual emissions, which are significantly lower in many cases). It should be noted that the costs were calculated in accordance with EPA's Cost Control Manual algorithms assuming an average retrofit cost and appropriately updated for inflation. Actual site-specific retrofit factors and considerations have not been taken into account, which very likely would increase the costs shown below. The calculated cost per ton of NO_X removal for each furnace is well above $3,750 per ton, making the implementation of additional controls (SNCR or LNB) **economically infeasible** for these sources. The detailed cost analyses are included in Appendix A.

Table 3-2. SNCR/LNB Control Costs for Furnaces

Emission Source ID	Source Description	SNCR Costs ($/ton of NO_X Removed)	LNB Costs ($/ton of NO_X Removed)
P001	HSM Reheat #1	N/A	$74,712
P002	HSM Reheat #2	N/A	$74,712
P003	HSM Reheat #3	N/A	$74,712
P004	HSM Reheat #4	N/A	$74,712
P005	HSM Reheat #5	N/A	$74,712
P011	Continuous Annealing	$59,236	$27,701

3.2.6 Step 5: Select RACT

As shown in Step 3 above, the top-down RACT analysis for the furnaces in question shows three control technologies that are technically feasible. Further, the results of the cost analysis shows that installation of SNCR on the continuous annealing furnace and/or retrofitting any of the furnaces with LNBs is cost prohibitive on a dollar per ton of NO_X removed basis. As such, the only remaining technically and economically feasible control technology is good combustion practices. For Step 5, the Irvin Plant proposes to continue to employ good combustion management practices as RACT III for the sources listed above. This will continue to be demonstrated through annual furnace/burner tune-up activities.

3.3 NO_X RACT Assessment for Combustion Units – Boilers

Boiler 1 and Boiler 2 are 79.8 MMBtu/hr and 84.6 MMBtu/hr heat input multi-fuel boilers, respectively. The units are capable of firing COG and/or natural gas as fuels. NO_x emission formation is driven by the same principles outlined in Section 3.2.

3.3.1 Step 1: Identify All Control Technologies for NO_x

Step 1 in a top-down analysis is to identify all available control technologies. Table 3-3 contains a list of the various technologies that have been identified for the control of NO_x from boilers.

Table 3-3. Potentially Available NO_X Control Technologies for Boilers

Potentially Applicable NO_X Control Technologies
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)
Low NO_X or Ultra Low NO_X Burner (LNB or ULNB)[9]
Good Combustion Practices

3.3.2 Review of Potentially Applicable NO_X Control Technologies

See Section 3.2.2 for details regarding the available control technologies, which, broadly speaking, are similar for boilers and furnaces. There are no new pollutant specific air cleaning devices or technologies since the RACT II evaluation.

3.3.3 Step 2: Eliminate Technically Infeasible Options for NO_X Control

Step 2 in a RACT top-down analysis is to eliminate the control options identified in Step 1 which are technically infeasible. The remaining technologies are then carried into Step 3.

3.3.3.1 Selective Non-Catalytic Reduction (SNCR)

As noted in Section 3.2.3.1, SCNR requires a high and narrow temperature range. The exhaust gases from the boilers would need to be preheated prior to treatment via SNCR. However, the control is deemed technically feasible for this type of operation.

3.3.3.2 Selective Catalytic Reduction (SCR)

SCR is considered technically feasible for this application although there are certain considerations that may complicate the level of control achievable. These considerations include, but are not limited to, the sulfur content of the fuel (i.e., COG fuel sulfur), which can leave to formation of sulfur trioxide (SO_3) and subsequently ammonium sulfur salts. The exhaust gases from the boilers would also need preheating prior to treatment via SCR

3.3.3.3 Low NO_X Burners (LNBs)

LNBs are considered technically feasible with respect to application on existing Boilers 1 and 2. The boilers already achieve a relatively low NO_X emissions rate which inherently limits the benefit of implementation of LNB technology.

3.3.3.4 Good Combustion Practices/Minimize Excess Air

The formation of NO_X can be minimized by proper boiler operation. Generally, this can be achieved through minimizing operating temperatures and controlling excess air. U. S. Steel already conducts annual tune-ups to ensure optimized combustion.

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[9] LNB and ULNB in combination with flue gas recirculation (FGR) was evaluated as part of the RACT II analysis. For the purposes of this report, this configuration is simply referred to as LNB/ULNB in this analysis.

3.3.4 Step 3: Rank Remaining Control Technologies by Control Effectiveness

In Step 3, the remaining control technology options are ranked based on their control effectiveness, from highest to lowest control efficiency. There are four (4) control technologies that are considered technically feasible: SCR, SNCR, LNB, and Good Combustion Practices. The ranking for the control technologies are as follows:

1. SCR
2. SNCR
3. LNB
4. Good Combustion Practices

3.3.5 Step 4: Evaluate Most Effective Controls and Document Results

U. S. Steel has evaluated the cost for installing SCR, SNCR and LNB on the two existing boilers. The costs shown have been conservatively calculated using potential-to-emit (rather than actual emissions, which are significantly lower in many cases). It should be noted that the costs were calculated in accordance with EPA's Cost Control Manual algorithms assuming an average retrofit cost and appropriately updated for inflation. Actual site-specific retrofit factors and considerations have not been taken into account, which very likely would increase the costs shown below. The calculated cost per ton of NO_X removal for each technology on each boiler is well above $3,750 per ton, making the implementation of additional controls (SCR, SNCR or LNB) **economically infeasible** for these sources. The detailed cost analyses are included in Appendix A.

Table 3-4. SCR/SNCR/LNB Control Costs for Boilers

Emission Source ID	Source Description	SCR Costs ($/ton of NO_X Removed)	SNCR Costs ($/ton of NO_X Removed)	LNB Costs ($/ton of NO_X Removed)
B001	Boiler No. 1	$31,178	$146,214	$11,202
B002	Boiler No. 2	$30,930	$146,341	$10,561

3.3.6 Step 5: Select RACT

As shown in Step 3 above, the top-down RACT analysis for Boilers No. 001 and No. 002 show three add-on control technologies that are technically feasible. Further, the results of the cost analysis (Step 4) shows that installation of SCR or SNCR and/or retrofitting the boilers with LNBs is cost prohibitive on a dollar per ton of NO_X removed basis. As such, the only remaining technically and economically feasible control technology is good combustion practices. For Step 5, the Irvin Plant proposes to continue to employ good combustion management practices as RACT III for the sources listed above. This will continue to be implemented through annual boiler tune-up activities.

3.4 VOC RACT Assessment for Cold Reduction Mill

The Irvin Plant operates the No. 3 five stand cold rolling mill (CRM), which is a source of VOC emissions due to the use of lubricants at the mill. The lubricant used is a water-oil emulsion. Through current permit conditions, the rolling oil emulsion is limited to an oil content by volume of 7% and the lubricating oil used in the water-oil emulsion is limited to 2% by weight VOC. Emissions from cold rolling can be characterized as a fog or aerosol of particulate matter and VOC from the rolling oil emulsion. Emissions from the CRM are controlled by a mist eliminator control system. Actual VOC emissions were estimated to be approximately 7.1 tons during calendar year 2021.

3.4.1 Step 1: Identify All Control Technologies for VOC

Step 1 in a top-down analysis is to identify all available control technologies. Based on past RACT evaluations for the site, and a review of the RBLC, there are no control technologies identified other than good work practices and mist eliminator to minimize emissions.

3.4.2 Review of Potentially Applicable VOC Control Technologies

The following section provides a discussion of each potentially applicable technology identified above as it might be applied to steel rolling mill VOC sources.

3.4.2.1 Mist Eliminator

Mist eliminators remove visible or entrained oil vapor, moisture, and VOC mist (partially considered to be particulate matter greater than 10 microns in diameter) from the gaseous stream of processes when liquid droplets come in contact with the mist eliminator's wire mesh surface/pad or filter. The liquids present in the gas stream are separated by either diffusion, impaction, or interception and are then collected, filtered and sent to a storage tank.

3.4.2.2 Good Work Practices

Good work practices may include, as already noted in the Title V permit, limiting VOC potential through restrictions of VOC content of lubricants, routine cleaning of the mist eliminator, partial enclosure and maintaining a negative air flow on the system.

3.4.3 Step 2: Eliminate Technically Infeasible Options for VOC Control

Step 2 in a RACT top-down analysis is to eliminate the control options identified in Step 1 which are technically infeasible. The remaining technologies are then carried into Step 3. Both technologies identified in Step 2 are technically feasible (i.e., they are already in place).

3.4.4 Step 3: Rank Remaining Control Technologies by Control Effectiveness

In Step 3, the remaining control technology options are ranked based on their control effectiveness, from highest to lowest control efficiency. Based on the analysis described above, there is only one (1) add-on control technology that is considered technically feasible for CRM (i.e., existing mist eliminator). The control is already employed at the Irvin Plant.

3.4.5 Step 4: Evaluate Most Effective Controls and Document Results

Since the Irvin Plant CRM is already equipped with mist eliminator, and the site employs good work practices, this was assumed to be the base case for RACT. No further analysis was needed.

3.4.6 Step 5: Select RACT

The RACT control strategy for the Irvin Plant CRM is continued use of the mist eliminator and good work practices. The Irvin Plant will continue to employ the technology and work practices as required by Title V permit existing conditions 1a, 1b and 1d under Section D, Process P008.

3.5 VOC RACT Assessment for HSM Roughing and Finishing Mill Oil Usage

Rolling mill VOC emissions result from the use of lubrication oils during steel slab rolling operations including fugitive losses during lubrication of equipment and processed slabs. At the Irvin Plant, water is generally used as a lubricant at the HSM. However, at times, a lubricating oil, which is an oil-water emulsion, is used as a lubricant at the HSM. If used, the HSM lubricant is limited to a maximum VOC content of 1% by weight. Without the use of rolling lubricant, a high amount of friction and heat is generated between the roller and the slab. Excessive friction can create enough heat to cause the steel slab to adhere to the rollers and in turn, cause deformation in the steel. Therefore, the presence of a lubricant (i.e., water or rolling oil solution) is paramount to ensuring consistent product quality and operation.

3.5.1 Step 1: Identify All Control Technologies for VOC

Step 1 in a top-down analysis is to identify all available control technologies. U. S. Steel is not aware of any VOC controls deployed in the industry that reduce VOC emissions from lubricating oils applied at hot strip mill roughing and finishing mills. There have not been any technological advancements since the RACT II analysis was performed. Restrictions on VOC content of lubricants and/or good operating practices are the only options identified through research.

3.5.2 Review of Potentially Applicable VOC Control Technologies

Restrictions on VOC content of lubricants and/or good operating practices are the only options identified through research. This is considered base case for the Irvin Plant.

3.5.3 Step 2: Eliminate Technically Infeasible Options for VOC Control

Step 2 in a RACT top-down analysis is to eliminate the control options identified in Step 1 which are technically infeasible. The Irvin Plant already employs the only control option identified in Step 1.

3.5.4 Step 3: Rank Remaining Control Technologies by Control Effectiveness

In Step 3, the remaining control technology options are ranked based on their control effectiveness, from highest to lowest control efficiency. This step is not applicable in this case since there is only one control option.

3.5.5 Step 4: Evaluate Most Effective Controls and Document Results

No further analysis was needed since the Irvin Plant already complies with good operating practices and an existing VOC restriction on the lubricant, if used.

3.5.6 Step 5: Select RACT

The RACT control strategy for the Irvin Plant HSM Rough and Finishing Mill oil usage (P016) is continued good work practices. For the purposes of RACT, this includes adherence to the 1% VOC, by weight, restriction for the oil-water emulsion when used at the process area (e.g., Condition 1d under Section D, Process P001).

4. RACT III PROPOSAL

Based on the analysis provided herein, U. S. Steel is proposing the following alternative RACT III requirements, including monitoring, testing, recordkeeping and reporting in the following sections. This document contains one (1) table for each source (or source type) subject to the alternative RACT III provisions.

4.1 Hot Strip Mill Reheat Furnaces

Emission Source ID(s):	P001, P002, P003, P004, P005
Source Description(s):	Hot Strip Mill Reheat Furnaces (with Coke Oven Gas and Natural Gas Firing): > Reheat Furnace 1 (140 MMBtu/hr) > Reheat Furnace 2 (140 MMBtu/hr) > Reheat Furnace 3 (140 MMBtu/hr) > Reheat Furnace 4 (140 MMBtu/hr) > Reheat Furnace 5 (140 MMBtu/hr)
Description of RACT:	Case-by-case
	1. Maintain and operate each source in accordance with the manufacturer's specifications and/or with good combustion/operating practices.

Proposed Monitoring:
- As per TV permit

Proposed Testing (see Section 6 under P001 in current permit):
- Perform annual burner inspection, maintenance, adjustment, and tuning (see current permit conditions)

Proposed Recordkeeping (see Section 4 under P011 in current permit):
- Monthly records of fuel consumption to each furnace
- Records of annual burner tune ups (see current permit conditions)

Proposed Reporting:
- Annual emissions reporting by March 15th of each year
- Semi-annual Title V monitoring report and Annual Title V compliance certification

4.2 Continuous Annealing Furnace

Emission Source ID(s):	P011
Source Description(s):	45 MMBtu/hr Continuous Annealing Furnace with Coke Oven Gas and Natural Gas Firing
Description of RACT:	Case-by-case
	1. Maintain and operate each source in accordance with the manufacturer's specifications and/or with good combustion/operating practices.

Proposed Monitoring:

> As per TV permit

Proposed Testing (see Section 6 under P011 in current permit):

> Perform annual burner inspection, maintenance, adjustment, and tuning (see current permit conditions)

Proposed Recordkeeping (see Section 4 under P011 in current permit):

> Monthly records of fuel consumption to each furnace
> Records of annual burner tune ups (see current permit conditions)

Proposed Reporting:

> Annual emissions reporting by March 15th of each year
> Semi-annual Title V monitoring report and Annual Title V compliance certification

4.3 Boilers

Emission Source ID(s):	B001, B002	
Source Description(s):	Boiler No. 1 (79.8 MMBtu/hr); Boiler No. 2 (84.6 MMBtu/hr); both fired coke oven gas and natural gas	
Description of RACT:	Case-by-case	
	1. Maintain and operate each source in accordance with the manufacturer's specifications and/or with good combustion/operating practices.	

Proposed Monitoring:

> As per TV permit

Proposed Testing (see Section 6 under B001 and B002 in current permit):

> Perform annual burner inspection, maintenance, adjustment, and tuning (see current permit conditions)

Proposed Recordkeeping (see Section 4 under B001 and B002 in current permit):

> Monthly records of fuel consumption to each furnace
> Records of annual burner tune ups (see current permit conditions)

Proposed Reporting:

> Annual emissions reporting by March 15th of each year
> Semi-annual Title V monitoring report and Annual Title V compliance certification

4.4 Cold Reduction Mill

Emission Source ID(s):	P008
Source Description(s):	Cold Reduction Mill (Mill Stands No. 1 to No. 5)
Description of RACT:	Case-by-case
	1. Install, maintain and operate in accordance with the manufacturer's specifications and/or with good operating practices 2. Operate with mist eliminator 3. Lubricating oil limited to 2% VOC by weight 4. Water-oil emulsion limited to 7% or less by volume oil content

Proposed Monitoring (see Section 3 under P008 in current permit):

- Measure inlet pressure of each collection and control system fan each week and after any cleaning on the cyclones (see current permit condition)

Proposed Testing:

- As per TV permit

Proposed Work Practices (see Section 3 and 6 under P008 in current permit):

- Inspect the CRM capture system and control system; one cyclone per week with each being inspected at least once every 5 weeks (see current permit condition)
- Maintain and operate the CRM in accordance with good air pollution control practices

Proposed Recordkeeping (see Section 4 under P008 in current permit):

- Keep type and VOC content of oils, the percent of oil in water-oil emulsion
- Keep record of emulsion used in CRM each day
- Keep records for a period of 5 years

Proposed Reporting (see Section 5 under P008 in current permit):

- Quarterly reports
- Annual emissions reporting by March 15th of each year
- Semi-annual Title V monitoring report and Annual Title V compliance certification

4.5 HSM Roughing and Finishing Mill Oil Usage

Emission Source ID(s):	P016
Source Description(s):	Hot Strip Mill, Roughing and Finishing Mill Oil Usage
Description of RACT:	Case-by-case
	1. Oil-water emulsion limited to 1% VOC by weight

<u>Proposed Monitoring:</u>

> As per TV permit

<u>Proposed Testing:</u>

> As per TV permit

<u>Proposed Work Practices:</u>

> As per TV permit

<u>Proposed Recordkeeping (see Section 4 under P001 in current permit):</u>

> Maintain records sufficient to demonstrate compliance with VOC limit including, but not limited to, documentation from all suppliers of oils used at the HSM.
> Keep records for a period of 5 years

<u>Proposed Reporting:</u>

> Annual emissions reporting by March 15th of each year
> Semi-annual Title V monitoring report and Annual Title V compliance certification

APPENDIX A. COST-EFFECTIVENESS CALCULATIONS

LNB Costs for Boilers

Source	Annualized Costs ($/yr)	NOx PTE (tpy)	Controlled Emissions (tpy)	Emissions Reduction (tpy)	Cost Effectiveness ($/ton)
Boiler 1	156,719	55.92	41.94	13.99	11,202
Boiler 2	156,719	59.29	44.47	14.84	10,561

COMPANY: United States Steel
LOCATION: Irvin
Source: Boiler #1
NOX Emission Control Option: Low NOx Burners

Site Information		Source Emission Information		Control Technology Information	
Utility Unit Costs[1]					
Electricity, $/kwh	**0.09**	Equipment Life, yr	**20.0**	Furnace Fuel Rating, mmBTU/hr	**80**
Interest Rate, %	**8.00%**	Operating Hours Per Year	**8760**	NOX Removal Efficiency, η_{NOx}	**25%**
Operating Costs				Cost Year	**2022**
Operating Labor, $/man-hr	**70**	Foundations and supports	**4%**		
Manhours per year	**0**	Handling and erection	**50%**	Incremental Utility Requirement	
Maintenance (Materials + Labor) % TCI	**1%**	Electrical	**8%**	Additional fan Electricity, kw	**0**
Property Tax % of TCI	**1%**	Piping	**1%**		
Insurance, % of TCI	**1%**	Insulation	**7%**		
Administration, % of TCI	**1%**	Painting	**4%**	Indirect Costs	
Overhead, % Labor & Mainteance	**60%**	Building preparation	**0%**	Construction and Field, % DC	**10%**
		Total Installation	**74%**	Engineering and Home Office Fees % DC	**20%**
Project Contingency % DC+IC	**20%**			Construction Fee % DC	**10%**
				Performance Test, % DC	**1%**
				Startup, % DC	**2%**
Direct Costs				Total Indirect	**43%**
Sales Tax, % of FOB	**7%**				
Freight & Ins. to Site, % of FOB	**5%**				
Instrumentation	**10%**				

Costing elements based upon the 1997 EPA Alternative Control Techniquests (ACT) document for "NOx Controls for Instituional, Commecial and Industrial (ICI) Boilers," Section 6 for natural gas firing and OAQPS Cost Manual 5th Ed.
1 - U. S. Steel specific rates for utilities, interest and labor.

COMPANY: United States Steel
LOCATION: Irvin
Source: Boiler #1
NOX Emission Control Option: Low NOx Burners

TOTAL CAPITAL INVESTMENT			TOTAL ANNUAL COST			COST EFFECTIVENESS	
Total Direct Capital Cost[1], DC			**Direct Annual Costs**			NOx$_{in\ Potential}$, lbs/MMBtu	0.16
Vendor Quoted Cost for Burners Only	$ 200,000		Operating & Supervisory Labor	$ -		Emissions After Control[1] lbs/MM	0.12
Instrumentation	$ 20,000		Maintenance	$ 11,048		Efficiency, %	25%
New Refractory and Windbox	$ 50,000		Reagent Consumption	$ -		Heat Input, MMBtu/hr	80
CFD Modeling	$ 20,000		Utilities	$ -		Total Operating Time, hrs/yr	8760
Total Capital	$ 290,000						
			Auxilliary Equipment Requirements	$ -		NO_X removed, tpy	14
Sales Tax	$ 20,300						
Freight & Ins. to Site	$ 14,500						
Direct Costs DC	$ 324,800		(Auxillary Heating Costs)	$ -			
Total Indirect Capital Costs:							
Indirect Capital, IC	$ 139,664		Total Direct Annual Costs		$ 11,048		
Project Contingency, C	$ 92,893						
Total Plant Cost, D (DC + IC + C)	$ 557,357		**Indirect Annual Costs**			**Cost Efficiency:**	
			Overhead	0.0		**$/ton NO_X removed**	**$ 11,202**
Direct Installation E	$ 214,600		Property Tax	$ 11,048			
			Insurance	$ 11,048			
Royalty Allowance,F	$ -		Adminstration charges	$ 11,048			
Preproduction Costs, G	$ -				$ 33,144		
Inventory Capital, H	$ -		Capital Recovery, CRF	0.102			
			IDAC (CRF x TCI)		$ 112,527		
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H)		**$ 1,104,805**	**TOTAL ANNUAL COST, TAC**		**$ 156,719**		

Notes:
1 - Cost estimates and NOx emission rates based upon burner vendor (John Zinc Hamworthy) submittal and follow-up discussions during RACT II evaluations. TCI updated based on current CEPCI compared t

COMPANY: United States Steel
LOCATION: Irvin
Source: Boiler #2
NOX Emission Control Option: Low NOx Burners

Site Information

Utility Unit Costs[1]

Electricity, $/kwh	**0.09**
Interest Rate, %	**8.00%**

Operating Costs

Operating Labor, $/man-hr	**70**
Manhours per year	**0**
Maintenance (Materials + Labor) % TCI	**1%**
Property Tax % of TCI	**1%**
Insurance, % of TCI	**1%**
Administration, % of TCI	**1%**
Overhead, % Labor & Mainteance	**60%**
Project Contingency % DC+IC	**20%**

Direct Costs

Sales Tax, % of FOB	**7%**
Freight & Ins. to Site, % of FOB	**5%**
Instrumentation	**10%**

Source Emission Information

Equipment Life, yr	**20.0**
Operating Hours Per Year	**8760**
Foundations and supports	**4%**
Handling and erection	**50%**
Electrical	**8%**
Piping	**1%**
Insulation	**7%**
Painting	**4%**
Building preparation	**0%**
Total Installation	**74%**

Control Technology Information

Furnace Fuel Rating, mmBTU/hr	**85**
NOX Removal Efficiency, η_{NOx}	**25%**
Cost Year	**2022**

Incremental Utility Requirement

Additional fan Electricity, kw	**0**

Indirect Costs

Construction and Field, % DC	**10%**
Engineering and Home Office Fees % DC	**20%**
Construction Fee % DC	**10%**
Performance Test, % DC	**1%**
Startup, % DC	**2%**
Total Indirect	**43%**

Costing elements based upon the 1997 EPA Alternative Control Techniquests (ACT) document for "NOx Controls for Instituional, Commecial and Industrial (ICI) Boilers," Section 6 for natural gas firing and OAQPS Cost Manual 5th Ed.

1 - U. S. Steel specific rates for utilities, interest and labor.

COMPANY: United States Steel
LOCATION: Irvin
Source: Boiler #2
NOX Emission Control Option: Low NOx Burners

TOTAL CAPITAL INVESTMENT			**TOTAL ANNUAL COST**			**COST EFFECTIVENESS**	
Total Direct Capital Cost[1], DC			**Direct Annual Costs**			$NOx_{in\ Potential}$, lbs/MMBtu	0.16
Vendor Quoted Cost for Burners Only	$ 200,000		Operating & Supervisory Labor	$ -		Emissions After Control[1] lbs/MMBtu	0.12
Instrumentation	$ 20,000		Maintenance	$ 11,048		Efficiency, %	25%
New Refractory and Windbox	$ 50,000		Reagent Consumption	$ -		Heat Input, MMBtu/hr	85
CFD Modeling	$ 20,000		Utilities	$ -		Total Operating Time, hrs/yr	8760
Total Capital	$ 290,000						
			Auxilliary Equipment Requirements	$ -		NO_X removed, tpy	15
Sales Tax	$ 20,300						
Freight & Ins. to Site	$ 14,500						
Direct Costs DC	$ 324,800		(Auxillary Heating Costs)	$ -			
Total Indirect Capital Costs:							
Indirect Capital, IC	$ 139,664		Total Direct Annual Costs		$ 11,048		
Project Contingency, C	$ 92,893						
Total Plant Cost, D (DC + IC + C)	$ 557,357		**Indirect Annual Costs**			**Cost Efficiency:**	
			Overhead	0.0		**$/ton NO_X removed**	**$ 10,561**
Direct Installation E	$ 214,600		Property Tax	$ 11,048			
			Insurance	$ 11,048			
Royalty Allowance,F	$ -		Adminstration charges	$ 11,048			
Preproduction Costs, G	$ -				$ 33,144		
Inventory Capital, H	$ -		Capital Recovery, CRF	0.102			
			IDAC (CRF x TCI)		$ 112,527		
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H)		**$ 1,104,805**	**TOTAL ANNUAL COST, TAC**		**$ 156,719**		

Notes:
1 - Cost estimates and NOx emission rates based upon burner vendor (John Zinc Hamworthy) submittal and follow-up discussions during RACT II evaluations. TCI updated based on current CEPCI compared to

SCR Costs for Boilers

Source	Annualized Costs ($/yr)	NOx PTE (tpy)	Controlled Emissions (tpy)	Emissions Reduction (tpy)	Cost Effectiveness ($/ton)
Boiler 1	1,394,772	55.92	11.18	44.74	31,178
Boiler 2	1,467,062	59.29	11.86	47.43	30,930

Heat Capacity Boiler Combustion Stack Gas

	BOILER #2		BOILER #1	
	Flue Gas Composition	Heat Capacity (Btu/ft^3/ºF)	Flue Gas Composition	Heat Capacity (Btu/ft^3/ºF)
H2O	7.3%	0.0225	7.3%	0.0225
O2	13.2%	0.0185	13.2%	0.0185
CO2	4.0%	0.0260	4.0%	0.0260
N2	75.5%	0.0185	75.5%	0.0185
Total	**100.0%**	**0.0191**	**100.0%**	**0.0191**

	BOILER #2		BOILER #1	
Flow (1)	21,812	scfm	20,500	scfm
Flow	**1.31E+06**	**scfh**	**1.23E+06**	**scfh**
Temperature$_{SCR\ in}$ (1)	**465**	**F**	**465**	**F**
Temperature$_{SCR\ out}$ (2)	**730**	**F**	**730**	**F**
ΔT	**265**	F	**265**	F
Heat Requirement	5.1	Btu/scf	5.1	Btu/scf
Natural Gas Eff'y	80.0%		80.0%	
Natural Gas Req'd	6.3	Btu / scf flue gas	6.3	Btu / scf flue gas
Natural Gas Req'd	6.32E-06	MMBtu/scf flue gas	6.32E-06	MMBtu/scf flue gas
Natural Gas Cost (4)	$11.03	/ MMbtu	$11.03	/ MMbtu
Max Hours of Operation	8,760	Hr/yr	8,760	Hr/yr
Annual Natural Gas Cost (5)	$799,712		$751,609	

(1) Flowrate and temperatures values are consistent with RACT II evaluation values.
(2) SCR temperature & efficiency from EPA Control Cost Manual, 6th Ed., NOx Controls, Fig 2.2.
(3) Utilizes the permit limits or potential-to-emit values in tpy based on 8,760 hrs/yr.
(4) EIA 2022 average NG prices for commercial consumers in 2022 (https://www.eia.gov/naturalgas/monthly/pdf/table_03.pdf)
(5) Annual NG Cost = $/MMBtu NG x MMBtu/scf flue gas x scf flue gas/hr x hrs/yr

SCR Design Parameters used for Estimation

Boiler #1 Max. Heat Input, Q_B = 79.8 MMBtu/hr

System Capacity Factor, CFtotal = CFplant x CFSCR

Capacity Factor, CF, a measure of the average annual use of the boiler in conjunction with the SCR system.

Worst-Case Actual	79.8	MMBtu/hr
Potential	79.8	MMBtu/hr

CFBoiler2= 1.00

t_{SCR} 365 days/yr

CF_{SCR}= 1.00

CF_{total}= 1.00 (CCM SCR June 2019, Equation 2.7)

Uncontrolled NO_X, Stack NO_X and NO_X Removal Efficiency

NOx_{in}, (uncontrolled)= 0.16 lb/MMBtu (Potential, effective permit limit)

NOx Removal Efficiency, η_{NOx} = 80%

Stoichiometric Ratio Factor, SRF (CCM SCR June 2019, Equation 2.13)

$$SRF = \frac{\text{moles of equivalent NH3 injected}}{\text{mole of uncontrolled } NO_X}$$

The value for SRF in a typical SCR system is approximately = 1.05 (CCM SCR June 2019, Section 2.3.7)

Flue Gas Flow Rate, $q_{fluegas}$

$q_{fluegas}$ = 37,156 acfm - based on testing at boilers (value consistent with RACT II)

Space Velocity and Area Velocity, V_{space} & V_{area} (CCM SCR June 2019, Section 2.3.9)

Vanadium (V2O5) Catalyst on honeycomb substract with average pitch assumed

$Vol_{reactor}$ = 0.02 ft^3/cfm

$Vol_{reactor}$ = 743.12 ft^3

$Area_{reactor}$ = 0.005 ft^2/cfm

$Area_{reactor}$ = 185.78 ft^2

$$V_{space} = \frac{1}{\text{Residence Time}} = \frac{q_{fluegas}}{Vol_{reactor}} = 50$$

$$V_{area} = \frac{V_{space}}{A_{specific}\,(\text{length}^2/\text{length}^3)} = 200$$

$A_{specific}$ (provided by catalyst manufacturer) = 0.25 /ft

Catalyst Volume, $Vol_{catalyst}$ (CCM SCR June 2019, Section 2.3.11)

$$Vol_{catalyst} = \frac{-\left(q_{fluegas} \times \ln\left[1 - \left(\frac{\eta_{NO_X}}{SRF}\right)\right]\right)}{K_{catalyst} \times A_{specific}}$$

$Vol_{catalyst} = Vol_{reactor}$ 743 ft^3 (Assumption)

SCR Reactor Dimensions

$$A_{catalyst} = \frac{q_{fluegas}}{16\ ft/s \times 60\text{sec/min}}$$

$A_{catalyst}$ = 38.7 ft^2

$A_{SCR} = 1.15 \times A_{catalyst}$

A_{SCR} = 44.5 ft^2

l_{scr} = 6.7 ft

w_{scr} = 6.7 ft

$$n_{layer} = \frac{Vol_{catalyst}}{h'_{layer} \times A_{catalyst}}$$

h'_{layer} =	3.1	ft (nominal height as per Section 2.3.11 of SCR manual)
n_{layer} =	6.2	(There must be at least two catalyst layers, Section 2.3.11 of SCR manual)

$$h_{layer} = \left(\frac{Vol_{catalyst}}{n_{layer} \times A_{catalyst}}\right) + 1$$

h_{layer} =	4.1	ft. (Standard industry range is 2.5 to 5.0 ft and 1 foot is added to account for space required above and below the catalyst material for module assembly.)

$n_{total} = n_{layer} + n_{empty}$

n_{empty} =	1	(Assumption)
n_{total} =	7.2	(This accounts for the fact that n_{layer} does not include any empty catalyst layers for the future installation of catalyst).

$h_{SCR} = n_{total} (c_1 + h_{layer}) + c_2$ (Height of SCR reactor)

c_1 =	7	(Constants based on common industry practice)
c_2 =	9	
h_{SCR} =	88.8	

Estimating Reagent Consumption and Tank Size (CCM SCR June 2019, Section 2.3.13)

$$\dot{m}_{reagent} = \frac{NO_{X_{in}} \times Q_B \times SRF \times \eta_{NO_X} \times M_{reagent}}{M_{NO_X}}$$

NOx_{in} =	0.160025063	lb/MMBtu
Q_B =	79.8	MMBtu/hr
SRF =	1.05	
η_{NO_X} =	80%	
$M_{reagent}$ =	17.03	grams NH_3/mole
M_{NOx} =	46.01	grams NO_2/mole
$\dot{m}_{reagent}$ =	4.0	lbs/hr

For ammonia,

$$\dot{m}_{sol} = \frac{\dot{m}_{reagent}}{C_{sol}}$$

C_{sol} =	19%	(Percent concentration of the aqueous reagent solution)	
= $\dot{m}_{sol}$	20.9	lbs/hr	

$$q_{sol} = \frac{\dot{m}_{sol}}{\rho_{sol}} v_{sol}$$

ρ_{sol} =	56	lb/ft^3	(For aqueous ammonia at 60ºF, Section 2.3.13 of SCR manual)
v_{sol} =	7.481	gal/ft^3	(Specific volume of aqueous ammonia at 60ºF, Section 2.3.13 of SCR manual)
q_{sol} =	2.8	gph	

Tank volume:

$Vol_{Tank} = q_{sol}$ x t

t =	14.0	days	(Common on site storage requirement, Section 2.3.13 of SCR manual)
Vol_{Tank} =	938	gallons	

TOTAL CAPITAL INVESTMENT, TCI

Assumptions:

* Anhydrous ammonia used as the reagent
* Allowed ammonia slip range: 2-5 ppm.
* Ceramic honeycomb catalyst with an operating life of 3 years at full load operations.
* Cost equations sufficient for NOx reduction efficiencies up to 90%.
* A correction factor for a new installation versus a retrofit installation is included to adjust capital costs.

TCI Includes: direct and indirect costs associated with purchasing and installing SCR equipment. Costs include the equipment cost (EC) for the SCR system itself, the cost of auxiliary equipment, direct and indirect installation costs, additional costs due to installation such as asbestos removal, costs for buildings and site preparation, offsite facilitites, land and working capital.

TOTAL CAPITAL INVESTMENT, TCI (CCM SCR June 2019, Section 2.4.1.4)

$$TCI = 10{,}530 \times \left(\frac{1{,}640}{Q_B}\right) \times Q_B \times ELEVF \times RF$$ (CCM SCR June 2019, Equation 2.53)

ELEVF =	1.03	Irvin Plant, PA is 940 ft above sea level (CCM SCR June 2019, Equation 2.39a)
RF =	1	Retrofit of average difficulty (CCM SCR June 2019, Equation 2.53)

Total Capital Investment (TCI) (2022 $) = $3,787,379 (Chemical Engineering Plant Index difference applied to DC)

TOTAL ANNUAL COSTS (CCM SCR June 2019, Section 2.4.2)

Consists of direct costs, indirect costs, and recovery credits. Direct annual costs are those proportional to the quantity of waste gas processed by the control system. Indirect (fixed) annual costs are independent of the operation of the control system and would be incurred even if it were shut down. No byproduct recovery credits are included because there are no salvageable byproducts generated from the SCR.

Direct Annual Costs, DAC

$$DAC = \begin{pmatrix} Annual \\ Maintenance \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Reagent \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Electricity \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Catalyst \\ Cost \end{pmatrix}$$ (CCM SCR June 2019, Equation 2.56)

<u>Operating and Supervisory Labor:</u>

In general, no additional personnel is required to operate or maintain the SCR equipment for large industrial facilities.

Operating labor time =		4	hr/day	(CCM SCR June 2019, Section 2.4.2)
Operating labor cost =	$	70	$/man-hr	
Annual operating labor cost =	$	102,200	= hr/day x 365 day/yr x $/man-hr	

<u>Maintenance:</u>

0.5% of TCI			(CCM SCR June 2019, Equation 2.57)
Maintenance =	$	18,937	

Total operating time, $t_{op} = CF_{total}$ x 8760 hrs/yr 8,760 hours (CCM SCR June 2019, Equation 2.59)

<u>Reagent Consumption:</u>

$cost_{reagent}$	0.5631	$/gallon	(Tanner Industries, Inc budgetary pricing for aqueous ammonia - 10/1/2020)
Annual reagent cost =	$ 13,770	$= q_{sol}$ x $cost_{reag}$ x t_{op}	(CCM SCR June 2019, Equation 2.58)

<u>Utilities:</u>

$$Power = (0.1 \times Q_B) \times (1{,}000) \times (0.0056) \times (CoalF \times HRF)^{0.43}$$ (CCM SCR June 2019, Equation 2.61)

CoalF=	1	For gas-fired boilers, replace the coal factor with "1"
HRF	1	For industrial boilers, assume NPHR=10; HRF = 1 (CCM SCR June 2019, Section 2.3.2)
Power =	44.7	kw
$Cost_{elec}$=	0.09	$/kwh (September 2022, U.S. EIA statistics for Pennsylvania)
t_{op} =	8,760	hours
Annual electricity cost = P x $Cost_{elect}$ x t_{op} =	$ 34,997	(CCM SCR June 2019, Equation 2.61)

Additional Energy Requirement = $ 751,609 (Additional heating of exhaust gas required for SCR operations.)

Catalyst Replacement:

Catalyst Replacement Cost = n_{SCR} x $Vol_{catalyst}$ x ($CC_{replace}/R_{layer}$) (CCM SCR June 2019, Equation 2.63)

R_{layer} =		1	for full replacement
R_{layer} =		6.2	=n_{layer} (for replacing one layer per year)
n_{SCR} =		1	(number of SCR reactors per boiler)
$CC_{initial}$=	$	227	per ft^3 (Default value CCM SCR June 2019, Section 2.5)
$Vol_{catalyst}$ =	$	743	ft^3
Catalyst Replacement Cost (2022 $)=	$	256,753.65	(Chemical Engineering Plant Index difference applied to DC)

Annual Catalyst Replacement Cost = (Catalyst Replacement Cost) x (FWF) (CCM SCR June 2019, Equation 2.64)

Future Worth Factor = $FWF = i\left[\frac{}{(1+}\right.$ (CCM SCR June 2019, Equation 2.65)

Interest rate, i =	8.00%	Prior Site-Specific Interest Rate Used in 4-Factor Analysis and BART Evaluation (Conservatively Low)
$Term, Y = \frac{h_{cat}}{h_{y}}$	3	(CCM SCR June 2019, Equation 2.66)
$h_{catalyst}$ =	24,000	hours (operating life of catalyst per CCM SCR June 2019, Section 2.4.2)
h_{year} =	8,760	hours = t_{op}
FWF =	0.34	

Annual Catalyst Replacement Cost = $ 87,506

Total DAC (2022 $)= $ 1,009,019

Indirect Annual Costs, IDAC:

Indirect Annual Cost, IDAC = Administrative Charges + Capital Recovery (CCM SCR June 2019, Equation 2.68)

Assume Administrative Charges are negligible

CR=CRF x TCI (CCM SCR June 2019, Equation 2.70)
CRF = Capital Recovery Factor,

$$CRF = \frac{i(1+i)^n}{(1+i)^n} - 1$$

Interest rate,i =	8.00%	Prior Site-Specific Interest Rate Used in 4-Factor Analysis (Conservatively Low)
Economic life of SNCR, n=	20	years
CRF =	0.102	

TCI = Total Capital Investment = $3,787,379

IDAC (2022 $) = $ 385,753

Total Annual Cost (2022 $):

Total Annual Cost, TAC = DAC + IDAC =	$ 1,394,772.34

COMPANY: United States Steel
LOCATION: Irvin
Source: Boiler #1
NOX Emission Control Option: SCR (80% Efficiency)

Site Information		Source Emission Information		Control Technology Information	
Utility Unit Costs					
Electricity, $/kwh	**0.09**	Equipment Life, yr	**20.0**	Boiler Fuel Rating, mmBTU/hr	**80**
Interest Rate, %	**8.00%**	Operating Hours Per Year	**8,760**	NOX Removal Efficiency, η_{NOx}	**80%**
				Cost Year	**2022**
Operating Labor, $/man-hr	**70.00**				
Manhours per year	**1,460**			Incremental Utility Requirement	
Sales Tax, % of FOB	**N/A**			Electricity, kw	**45**
Freight & Ins. to Site, % of FOB	**Included in DC**			Reagent sol, gal/hr	**2.8**
Maintenance (Materials + Labor) % TCI	**0.5%**			Catalyst operating life, hrs	**24,000**
				Reagent Volume, gallons/hr	**2.8**
				Reagent Cost, $/gallon	**0.56**

COMPANY: United States Steel
LOCATION: Irvin
Source: Boiler #1
NOX Emission Control Option: SCR (80% Efficiency)

TOTAL CAPITAL INVESTMENT			**COST EFFECTIVENESS**	
TOTAL CAPITAL INVESTMENT, TCI		**$ 3,787,379**		
TOTAL ANNUAL COST			Efficiency, %	80%
			Boiler Heat Input, MMBtu/hr	80
Direct Annual Costs			Total Operating Time, hrs/yr	8,760
Operating & Supervisory Labor	$102,200			
Maintenance	$18,937		NO_X removed, tpy	44.7
Reagent Consumption	$13,770			
Utilities	$34,997			
Catalyst Replacement	$87,506			
Auxilliary Equipment Requirements	$751,609			
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SCR required temperature.)			**Cost Efficiency:**	
			$/ton NO_X removed	**$ 31,178**
Total Direct Annual Costs	$1,009,019			
Indirect Annual Costs				
CRF	0.10185			
IDAC (CRF x TCI)	$385,753			
TOTAL ANNUAL COST, TAC	**$1,394,772**			

SCR Design Parameters used for Estimation

Boiler #2 Max. Heat Input, Q_B = 84.6 MMBtu/hr

System Capacity Factor, CFtotal = CFplant x CFSCR

Capacity Factor, CF, a measure of the average annual use of the boiler in conjunction with the SCR system.

Worst-Case Actual	84.6	MMBtu/hr
Potential	84.6	MMBtu/hr

CFBoiler2= 1.00

t_{SCR} 365 days/yr

CF_{SCR}= 1.00

CF_{total}= 1.00 (CCM SCR June 2019, Equation 2.7)

Uncontrolled NO_X, Stack NO_X and NO_X Removal Efficiency

NOx_{in}, (uncontrolled)= 0.16 lb/MMBtu (Potential, effective permit limit)

NOx Removal Efficiency, η_{NOx} = 80%

Stoichiometric Ratio Factor, SRF (CCM SCR June 2019, Equation 2.13)

$$SRF = \frac{\text{moles of equivalent NH3 injected}}{\text{mole of uncontrolled } NO_X}$$

The value for SRF in a typical SCR system is approximately = 1.05 (CCM SCR June 2019, Section 2.3.7)

Flue Gas Flow Rate, $q_{fluegas}$

$q_{fluegas}$ = 39,530 acfm - based on testing at boilers (value consistent with RACT II)

Space Velocity and Area Velocity, V_{space} & V_{area} (CCM SCR June 2019, Section 2.3.9)

Vanadium (V2O5) Catalyst on honeycomb substract with average pitch assumed

$Vol_{reactor}$ = 0.02 ft^3/cfm

$Vol_{reactor}$ = 790.6 ft^3

$Area_{reactor}$ = 0.005 ft^2/cfm

$Area_{reactor}$ = 197.65 ft^2

$$V_{space} = \frac{1}{\text{Residence Time}} = \frac{q_{fluegas}}{Vol_{reactor}} = 50$$

$$V_{area} = \frac{V_{space}}{A_{specific}\,(\text{length}^2/\text{length}^3)} = 200$$

$A_{specific}$ (provided by catalyst manufacturer) = 0.25 /ft

Catalyst Volume, $Vol_{catalyst}$ (CCM SCR June 2019, Section 2.3.11)

$$Vol_{catalyst} = \frac{-\left(q_{fluegas} \times \ln\left[1-\left(\frac{\eta_{NO_X}}{SRF}\right)\right]\right)}{K_{catalyst} \times A_{specific}}$$

$Vol_{catalyst} = Vol_{reactor}$ 791 ft^3 (Assumption)

SCR Reactor Dimensions

$$A_{catalyst} = \frac{q_{fluegas}}{16\,ft/s \times 60\text{sec/min}}$$

$A_{catalyst}$ = 41.2 ft^2

$A_{SCR} = 1.15 \times A_{catalyst}$

A_{SCR} = 47.4 ft^2

l_{scr} = 6.9 ft

w_{scr} = 6.9 ft

$$n_{layer} = \frac{Vol_{catalyst}}{h'_{layer} \times A_{catalyst}}$$

h'_{layer} =	3.1	ft (nominal height as per Section 2.3.11 of SCR manual)
n_{layer} =	6.2	(There must be at least two catalyst layers, Section 2.3.11 of SCR manual)

$$h_{layer} = \left(\frac{Vol_{catalyst}}{n_{layer} \times A_{catalyst}}\right) + 1$$

h_{layer} =	4.1	ft. (Standard industry range is 2.5 to 5.0 ft and 1 foot is added to account for space required above and below the catalyst material for module assembly.)

$n_{total} = n_{layer} + n_{empty}$

n_{empty} =	1	(Assumption)
n_{total} =	7.2	(This accounts for the fact that n_{layer} does not include any empty catalyst layers for the future installation of catalyst).

$h_{SCR} = n_{total}\,(c_1 + h_{layer}) + c_2$ (Height of SCR reactor)

c_1 =	7	(Constants based on common industry practice)
c_2 =	9	
h_{SCR} =	88.8	

Estimating Reagent Consumption and Tank Size (CCM SCR June 2019, Section 2.3.13)

$$\dot{m}_{reagent} = \frac{NOx_{in} \times Q_B \times SRF \times \eta_{NO_X} \times M_{reagent}}{M_{NO_X}}$$

NOx_{in} =	0.160047281	lb/MMBtu
Q_B =	84.6	MMBtu/hr
SRF =	1.05	
η_{NO_X} =	80%	
$M_{reagent}$ =	17.03	grams NH_3/mole
M_{NOx} =	46.01	grams NO_2/mole
$\dot{m}_{reagent}$ =	4.2	lbs/hr

For ammonia,

$$\dot{m}_{sol} = \frac{\dot{m}_{reagent}}{C_{sol}}$$

C_{sol} =	19%	(Percent concentration of the aqueous reagent solution)	
= $\dot{m}_{sol}$	22.2	lbs/hr	

$$q_{sol} = \frac{\dot{m}_{sol}}{\rho_{sol}} v_{sol}$$

ρ_{sol} =	56	lb/ft^3	(For aqueous ammonia at 60ºF, Section 2.3.13 of SCR manual)
v_{sol} =	7.481	gal/ft^3	(Specific volume of aqueous ammonia at 60ºF, Section 2.3.13 of SCR manual)
q_{sol} =	3.0	gph	

Tank volume:

$Vol_{Tank} = q_{sol}$ x t

t =	14.0	days	(Common on site storage requirement, Section 2.3.13 of SCR manual)
Vol_{Tank} =	995	gallons	

TOTAL CAPITAL INVESTMENT, TCI

Assumptions:

* Anhydrous ammonia used as the reagent
* Allowed ammonia slip range: 2-5 ppm.
* Ceramic honeycomb catalyst with an operating life of 3 years at full load operations.
* Cost equations sufficient for NOx reduction efficiencies up to 90%.
* A correction factor for a new installation versus a retrofit installation is included to adjust capital costs.

TCI Includes: direct and indirect costs associated with purchasing and installing SCR equipment. Costs include the equipment cost (EC) for the SCR system itself, the cost of auxiliary equipment, direct and indirect installation costs, additional costs due to installation such as asbestos removal, costs for buildings and site preparation, offsite facilitites, land and working capital.

TOTAL CAPITAL INVESTMENT, TCI (CCM SCR June 2019, Section 2.4.1.4)

$$TCI = 10{,}530 \times \left(\frac{1{,}640}{Q_B}\right) \times Q_B \times ELEVF \times RF$$ (CCM SCR June 2019, Equation 2.53)

ELEVF =	1.03	Irvin Plant, PA is 940 ft above sea level (CCM SCR June 2019, Equation 2.39a)
RF =	1	Retrofit of average difficulty (CCM SCR June 2019, Equation 2.53)

Total Capital Investment (TCI) (2022 $) = $3,933,939 (Chemical Engineering Plant Index difference applied to DC)

TOTAL ANNUAL COSTS (CCM SCR June 2019, Section 2.4.2)

Consists of direct costs, indirect costs, and recovery credits. Direct annual costs are those proportional to the quantity of waste gas processed by the control system. Indirect (fixed) annual costs are independent of the operation of the control system and would be incurred even if it were shut down. No byproduct recovery credits are included because there are no salvageable byproducts generated from the SCR.

Direct Annual Costs, DAC

$$DAC = \begin{pmatrix} Annual \\ Maintenance \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Reagent \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Electricity \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Catalyst \\ Cost \end{pmatrix}$$ (CCM SCR June 2019, Equation 2.56)

Operating and Supervisory Labor:
In general, no additional personnel is required to operate or maintain the SCR equipment for large industrial facilities.

Operating labor time =		4	hr/day	(CCM SCR June 2019, Section 2.4.2)
Operating labor cost =	$	70	$/man-hr	
Annual operating labor cost =	$	102,200	= hr/day x 365 day/yr x $/man-hr	

Maintenance:

0.5% of TCI			(CCM SCR June 2019, Equation 2.57)
Maintenance =	$	19,670	

Total operating time, $t_{op} = CF_{total}$ x 8760 hrs/yr 8,760 hours (CCM SCR June 2019, Equation 2.59)

Reagent Consumption:

$cost_{reagent}$		0.5631	$/gallon (Tanner Industries, Inc budgetary pricing for aqueous ammonia - 10/1/2020)
Annual reagent cost =	$	14,601	= q_{sol} x $cost_{reag}$ x t_{op} (CCM SCR June 2019, Equation 2.58)

Utilities:

$$Power = (0.1 \times Q_B) \times (1{,}000) \times (0.0056) \times (CoalF \times HRF)^{0.43}$$ (CCM SCR June 2019, Equation 2.61)

CoalF=		1	For gas-fired boilers, replace the coal factor with "1"
HRF		1	For industrial boilers, assume NPHR=10; HRF = 1 (CCM SCR June 2019, Section 2.3.2)
Power =		47.4	kw
$Cost_{elec}$=		0.09	$/kwh (September 2022, U.S. EIA statistics for Pennsylvania)
t_{op} =		8,760	hours
Annual electricity cost = P x $Cost_{elect}$ x t_{op} =	$	37,102	(CCM SCR June 2019, Equation 2.61)
Additional Energy Requirement =	$	799,712	(Additional heating of exhaust gas required for SCR operations.)

Catalyst Replacement:

Catalyst Replacement Cost = n_{SCR} x $Vol_{catalyst}$x ($CC_{replace}$/$R_{layer)}$ (CCM SCR June 2019, Equation 2.63)

R_{layer} =	1	for full replacement
R_{layer} =	6.2	=n_{layer} (for replacing one layer per year)
n_{SCR} =	1	(number of SCR reactors per boiler)
$CC_{initial}$=	$ 227	per ft^3 (Default value CCM SCR June 2019, Section 2.5)
$Vol_{catalyst}$ =	$ 791	ft^3
Catalyst Replacement Cost (2022 $)=	$ 273,158.36	(Chemical Engineering Plant Index difference applied to DC)

Annual Catalyst Replacement Cost = (Catalyst Replacement Cost) x (FWF) (CCM SCR June 2019, Equation 2.64)

Future Worth Factor = $FWF = i\left[\frac{}{(1+}\right.$ (CCM SCR June 2019, Equation 2.65)

Interest rate, i =	8.00%	Prior Site-Specific Interest Rate Used in 4-Factor Analysis and BART Evaluation (Conservatively Low)
$Term, Y = \frac{h_{cat}}{h_{y}}$	3	(CCM SCR June 2019, Equation 2.66)
$h_{catalyst}$ =	24,000	hours (operating life of catalyst per CCM SCR June 2019, Section 2.4.2)
h_{year} =	8,760	hours = t_{op}
FWF =	0.34	
Annual Catalyst Replacement Cost =	$ 93,097	
Total DAC (2022 $)=	$ 1,066,382	

Indirect Annual Costs, IDAC:

Indirect Annual Cost, IDAC = Administrative Charges + Capital Recovery (CCM SCR June 2019, Equation 2.68)

Assume Administrative Charges are negligible

CR=CRF x TCI (CCM SCR June 2019, Equation 2.70)
CRF = Capital Recovery Factor,

$$CRF = \frac{i(1+i)^n}{(1+i)^n} - 1$$

Interest rate,i =	8.00%	Prior Site-Specific Interest Rate Used in 4-Factor Analysis (Conservatively Low)
Economic life of SNCR, n=	20	years
CRF =	0.102	
TCI = Total Capital Investment =	$3,933,939	
IDAC (2022 $) =	$ 400,680	

Total Annual Cost (2022 $):

Total Annual Cost, TAC = DAC + IDAC =	$ 1,467,061.99

COMPANY: United States Steel
LOCATION: Irvin
Source: Boiler #2
NOX Emission Control Option: SCR (80% Efficiency)

Site Information		Source Emission Information		Control Technology Information	
Utility Unit Costs					
Electricity, $/kwh	0.09	Equipment Life, yr	20.0	Boiler Fuel Rating, mmBTU/hr	85
Interest Rate, %	8.00%	Operating Hours Per Year	8,760	NOX Removal Efficiency, η_{NOx}	80%
				Cost Year	2022
Operating Labor, $/man-hr	70.00				
Manhours per year	1,460			Incremental Utility Requirement	
Sales Tax, % of FOB	N/A			Electricity, kw	47
Freight & Ins. to Site, % of FOB	Included in DC			Reagent sol, gal/hr	3.0
Maintenance (Materials + Labor) % TCI	0.5%			Catalyst operating life, hrs	24,000
				Reagent Volume, gallons/hr	3.0
				Reagent Cost, $/gallon	0.56

COMPANY: United States Steel
LOCATION: Irvin
Source: Boiler #2
NOX Emission Control Option: SCR (80% Efficiency)

TOTAL CAPITAL INVESTMENT			**COST EFFECTIVENESS**	
TOTAL CAPITAL INVESTMENT, TCI		**$ 3,933,939**		
TOTAL ANNUAL COST			Efficiency, %	80%
			Boiler Heat Input, MMBtu/hr	85
Direct Annual Costs			Total Operating Time, hrs/yr	8,760
Operating & Supervisory Labor	$102,200			
Maintenance	$19,670		NO_X removed, tpy	47.4
Reagent Consumption	$14,601			
Utilities	$37,102			
Catalyst Replacement	$93,097			
Auxilliary Equipment Requirements	$799,712			
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SCR required temperature.)			**Cost Efficiency:**	
			$/ton NO_X removed	**$ 30,930**
Total Direct Annual Costs	$1,066,382			
Indirect Annual Costs				
CRF	0.10185			
IDAC (CRF x TCI)	$400,680			
TOTAL ANNUAL COST, TAC	**$1,467,062**			

SNCR Costs for Boilers

Source	Annualized Costs ($/yr)	NOx PTE (tpy)	Controlled Emissions (tpy)	Emissions Reduction (tpy)	Cost Effectiveness ($/ton)
Boiler 1	3,679,341	55.92	30.76	25.16	146,214
Boiler 2	3,904,443	59.29	32.61	26.68	146,341

Heat Capacity Boiler Combustion Stack Gas

	BOILER #2		BOILER #1	
	Flue Gas Composition	Heat Capacity (Btu/ft^3/°F)	Flue Gas Composition	Heat Capacity (Btu/ft^3/°F)
H2O	7.3%	0.0225	7.3%	0.0225
O2	13.2%	0.0185	13.2%	0.0185
CO2	4.0%	0.0260	4.0%	0.0260
N2	75.5%	0.0185	75.5%	0.0185
Total	**100.0%**	**0.0191**	**100.0%**	**0.0191**

	BOILER #2		BOILER #1	
Flow (1)	21,812	scfm	20,500	scfm
Flow	**1.31E+06**	**scfh**	**1.23E+06**	**scfh**
Temperature$_{SNCR\ in}$ (1)	**465**	**F**	**465**	**F**
Temperature$_{SNCR\ out}$ (2)	**1650**	**F**	**1650**	**F**
ΔT	**1185**	F	**1185**	F
Heat Requirement	22.6	Btu/scf	22.6	Btu/scf
Uncontrolled NOX (3)	13.54	lb / hr	12.77	lb / hr
NOX control eff'y (2)	45.0%		45.0%	
NOX Removed	6.1	lb / hr	5.7	lb / hr
NOX Removed	4.66E-06	lb/scf flue gas	4.67E-06	lb/scf flue gas
NOX from Natural Gas Combustion (4)	3.96E-06	lb/scf flue gas	3.96E-06	lb/scf flue gas
Net NOX Reduction	6.96E-07	lb/scf flue gas	7.13E-07	lb/scf flue gas
Natural Gas Eff'y	80.0%		80.0%	
Natural Gas Req'd	28.3	Btu/scf flue gas	28.3	Btu/scf flue gas
Natural Gas Req'd	2.83E-05	MMBtu/scf flue gas	2.83E-05	MMBtu/scf flue gas
Natural Gas Cost (5)	$11.03	/ MMbtu	$11.03	/ MMbtu
Natural Gas Cost	$447.86	/lb NOX Removed	$437.64	/lb NOX Removed
Annual Natural Gas Cost (6)	$3,576,071		$3,360,969	

(1) Flowrate and temperatures values are consistent with RACT II evaluation values.
(2) SNCR temperature & efficiency from EPA Control Cost Manual, 6th Ed., NOX Controls, Fig 1.5. (Maximum uncontrolled NOX concentration displayed is 200 ppm.)
(3) Utilizes the permit limits or potential-to-emit values in tpy based on 8,760 hrs/yr.
(4) Based on 140 lb NOX per MMscf natural gas
(5) EIA 2022 average NG prices for commercial consumers in 2022 (https://www.eia.gov/naturalgas/monthly/pdf/table_03.pdf)
(6) Annual NG Cost = $/MMBtu NG x MMBtu/scf flue gas x scf flue gas/hr x 8760 hrs/yr

SNCR Design Parameters used for Estimation

Boiler #1 Max. Heat Input, Q_B = 79.8 MMBtu/hr

System Capacity Factor, CF_{total} = CF_{plant} x CF_{SNCR}

Capacity Factor, CF, a measure of the average annual use of the boiler in conjunction with the SNCR system.

$$CF_{plant} = \frac{FuelUsage_{annual}, lbs}{FuelUsage_{potential}, lbs}$$

$$CF_{Boiler\#2} = \frac{Actual_{2018}, MMBtu/hr}{Potential, MMBtu/hr}$$

Worst-Case Actual	79.8	MMBtu/hr
Potential	79.8	MMBtu/hr

CFBoiler2= 1.00

$$CF_{SNCR} = \frac{t_{SNCR}(days/yr)}{365(days/yr)}$$

t_{SNCR} 365 days/yr

CF_{SNCR}= 1.00

CF_{total}= 1.00

Uncontrolled NO_X, Stack NO_X and NO_X Removal Efficiency

NOx_{in}, (uncontrolled)= 0.16 lb/MMBtu (Potential, effective permit limit)

NOX Removal Efficiency, η_{NOx} = 45%

Normalized Stoichiometric Ratio, NSR (Equation 1.17 of SNCR manual)

$$NSR = \frac{\left[\left(\frac{2\ mol\ Urea}{mol\ NO_X}\right) \times NO_{X_{in}} + 0.7\right] \times \eta_{NO_x}}{NO_{X_{in}}}$$

NSR = 2.87

Estimating Reagent Consumption

Reagent Consumption Parameters:

ρ_{sol} =	9.5	Density of aqueous reagent solution (lb/gal) (For a 50% urea solution, as per page 1-38 of SNCR Manual)
$M_{reagent}$ =	60.06	Molecular weight of reagent (grams/mol Urea)
M_{NO2}=	46.01	Molecular weight of NO_2 (grams/mol NO_2)
SR_T=	2	Ratio of equivalent moles of NH_3 per mole of reagent (mols NH_3/mol Urea)
C_{sol} =	0.5	Concentration of aqueous reagent solution by weight (lb reagent/lb solution) (50% solution)

Reagent mass flow rate:

$$\dot{m}_{reagent} = \frac{NO_{X_{in}} \times Q_B \times \eta_{NOx} \times NSR \times M_{reagent}}{M_{NO_2} \times SR_T}$$ (Equation 1.18 of SNCR manual)

$\dot{m}_{reagent}$ = 10.8 lbs/hr

Aqueous reagent solution mass flow rate: (Equation 1.19 of SNCR manual)

$$\dot{m}_{sol} = \frac{\dot{m}_{reagent}}{C_{sol}}$$

$\dot{m}_{sol}$ = 21.5 lbs/hr

Solution volume flow rate: (Equation 1.20 of SNCR manual)

$$q_{sol} = \frac{\dot{m}_{sol}}{\rho_{sol}}$$

q_{sol} = 2.27 gph

Aqueous reagent solution storage:

$V_{tank} = q_{sol} \times t_{storage}$

$t_{storage}$ = 14.00 days (Assumption from pg. 1-39 in SNCR manual)

V_{tank} = 761.72 gallons

TOTAL CAPITAL INVESTMENT, TCI

Cost Year = 1998

equipment, direct and indirect installation costs, additional costs due to installation such as asbestos removal, costs for buildings and site preparation, offsite facilitites, land and working capital.

DC=	Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. This includes costs associated with field measurements, numberical modeling and system design. It also includes direct installation costs such as auxiliary equipment (e.g.ductwork, compressor), foundations and supports, handling and erection, electrical, piping, insulation and painting. In addition costs such as asbestos removal are included.
PEC=	Purchased Equipment Cost
IC=	Indirect Capital

Total Direct Capital Costs, DC:

$$DC = \frac{\$950}{\frac{MMBtu}{hr}} Q_B \left(\frac{MMBtu}{hr}\right) \left\{\frac{2375\frac{MMBtu}{hr}}{Q_B\left(\frac{MMBtu}{hr}\right)}\right\}^{0.577} \left(0.66 + 0.85\eta_{NO_X}\right)$$

DC (2022 $) = $ 1,185,190.05 (Chemical Engineering Plant Index difference applied to DC)

Indirect Capital Costs:

Total Indirect Installation Costs, IC (2022 $) = $ 237,038

=DC x (General Facilities % + Engineering and Home Office Fees % + Process Contingency %)

General Facilities % =	5%	
Engineering and Home Office Fees % =	10%	
Process Contingency % =	5%	
Project Contingency, C =	$ 213,334.21	
=	15%	of DC + IC
Total Plant Cost, D =	$ 1,635,562.26	= DC + IC + C

Allowance for Funds During Construction, E =	$	-	(Assumed zero for SNCR)	
Royalty Allowance,F =	$	-	(Assumed zero for SNCR)	
Preproduction Costs, G =	$	32,711.25		
=		2%	of D + E	
Inventory Capital, H =	$	67,095.17	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)	
$Vol_{reagent}$ =		19,805	gal/yr	
$Cost_{reagent}$ =		3.39	$/gal	$/gallon (Mundi Price Index for September 2022, United States)
Initial Catalyst and Chemicals, I =	$	-	(Assumed zero for SNCR)	
Total Capital Investment, TCI =	$	1,735,368.68	= D + E + F + G + H + I	

TOTAL ANNUAL COSTS

TAC = Total Annual Cost
Includes: direct costs, indirect costs, and recovery credits.

DAC = Direct Annual Costs
Include: variable and semivariable costs.
Variable includes: purchase of reagent, utilities, and any additional fuel and ash disposal resulting from the operation of the
Semivariable include: operating and supervisory labor and maintenance.

$$DAC = \begin{pmatrix} Annual \\ Maintenance \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Reagent \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Electricity \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Water \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Fuel \\ Cost \end{pmatrix}$$

<u>Operating and Supervisory Labor:</u>
In general, no additional personnel is required to operate or maintain the SNCR equipment for large industrial facilities.

<u>Maintenance:</u>

1.5% of TCI
Maintenance = $ 26,031

Total operating time, $t_{op} = CF_{total} \times 8760$ hrs/yr 8760 hours (CF not used as max hours required for BART analysis)

Reagent Consumption (Urea):

$cost_{reagent}$		3.39	\$/gallon (Mundi Price Index for September 2022, United States)
Annual reagent cost =	\$	67,279	= q_{sol} x $cost_{reagent}$ x t_{op}

Utilities:

Power Consumption, P:

$$P = \frac{0.47 \times NOx_{in} \times NSR \times Q_B}{9.5}$$

NOx_{in}, (uncontrolled)=		0.160	lb/MMBtu
NSR (Normalized Stoichiometric Ratio):		2.87	
Q_B, boiler heat input=		79.8	MMBtu/hr
P =		2	kw
$Cost_{elec}$ =		0.09	\$/kwh (September 2022, U.S. EIA statistics for Pennsylvania)
t_{op} =		8760	hours
Annual electricity cost = P x $Cost_{elect}$ x t_{op} =	\$	1,419	per kWh

Water Consumption:

$$q_{water} = \frac{\dot{m}_{sol}}{\rho_{water}}\left(\frac{C_{UreaSol_{stored}}}{C_{UreaSol_{inj}}} - 1\right)$$

For urea dilution from a 50% solution to a 10% solution q_{water} becomes:

$$q_{water} = \frac{4\dot{m}_{sol}}{\rho_{water}}$$

ρ_{water} =	8.345	lb/gal
q_{water} =	0.010	1,000 gallons/hour

Annual water cost = q_{water} x $Cost_{water}$ x t_{op} =

$Cost_{water}$ =		15.05	\$/1,000 gallons (2022 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for ≥10" Meter)
	\$	1,360.08	

Additional Fuel Consumption:

Because the water from the urea solution evaporates in the boiler, the boiler efficiency decreases. Consequently, more fuel needs to be burned to maintain the required steam flow.
Assumptions:
- Urea is injected at at 10% solution
- Heat of vaporization of water is 900 Btu/lb

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) = \frac{900\left(\frac{Btu}{lb}\right)}{10^6\left(\frac{Btu}{MMBtu}\right)} \times \dot{m}_{reagent}\left(\frac{lb}{hr}\right) \times 9$$

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) \quad = \quad 0.0871$$

Annual cost for additional fuel:

Additional fuel required:

Natural gas	0.08714	MMBtu/hr

Total cost associated with additional fuel usage:

Natural gas cost	9.44	$/MMBtu	(left as conservatively low value; current price is 17.29)
	$ 7,206.32	$/yr	
Total Natural gas:	$ 7,206.32		
Additional Energy Requirement =	$ 3,360,969	(Additional heating of exhaust gas required for SNCR operations.)	
Total DAC =	$ 3,464,264.75		

Indirect Annual Costs:

Indirect Annual Cost, IDAC = CRF x TCI
CRF = Capital Recovery Factor,

$$CRF = \frac{i(1+i)^n}{(1+i)^n} - 1$$

Interest rate,i =	8.00%	Prior Site-Specific Interest Rate Used in 4-Factor Analysis and BART Evaluation (Conservatively Low)
Economic life of SNCR, n=	20	years
CRF =	0.10	

TCI = Total Capital Investment (2020 $) = $ 1,735,368.68

IDAC = $ 176,751.13

Total Annual Cost (2022 $):
Total Annual Cost, TAC = DAC + IDAC = $ 3,641,015.89

COMPANY: **United State Steel**
LOCATION: **Irvin**
Source: **Boiler #1**
NO_X Emission Control Option: **SNCR (45% Efficiency)**

Site Information

Utility Unit Costs	
Electricity, $/kwh	**0.09**
Interest Rate, %	**8.00%**
Water, $/1,000 gal	**15.05**
NG, $/MMBtu	**9.44**
Operating Labor, $/man-hr	**70.00**
Manhours per year	**547.5**
Sales Tax, % of FOB	**Included in DC**
Freight & Ins. to Site, % of FOB	**Included in DC**
Maintenance (Materials + Labor) % TCI	**1.5%**
General Facilities, % DC	**5%**
Engineering and Home Office Fees % DC	**10%**
Process Contingency % DC	**5%**
Project Contingency % DC+IC	**15%**
Preproduction Costs % of D+E	**2%**

Source Emission Information

Equipment Life, yr	**20.0**
Operating Hours Per Year	**8760**

Control Technology Information

Boiler Fuel Rating, mmBTU/hr	**80**
NOX Removal Efficiency, η_{NOx}	**45%**
Cost Year	**2022**
Incremental Utility Requirements	
Electricity, kw	**2**
Reagent sol, gal/hr	**2.27**
Water, 1,000 gal/hr	**0.01**
NG, MMBtu/hr	**0.08714**
Reagent Volume, gallons	**19,805**
Reagent Cost, $/gallon	**3.39**

COMPANY: United State Steel
LOCATION: Irvin
Source: Boiler #1
NO_X Emission Control Option: SNCR (45% Efficiency)

TOTAL CAPITAL INVESTMENT			TOTAL ANNUAL COST			COST EFFECTIVENESS	
Total Direct Capital Cost, DC	$ 1,185,190		**Direct Annual Costs**			NOX_{in}, lbs/MMBtu	0.16
Auxilliary Equipment (Heat Exchanger	$ -		Operating & Supervisory Labor	$38,325		Efficiency, %	45%
Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.			Maintenance	$26,031		Boiler Heat Input, MMBtu/hr	79.8
			Reagent Consumption	$67,279		Total Operating Time, hrs/yr	8760
			Utilities	$1,419			
			Water Consumption	$1,360		NO_X removed, tpy	25.2
Total Indirect Capital Costs:			Add'l Fuel Usage (Process related)	$7,206.32			
Indirect Capital, IC	$ 237,038		Auxiliary Equipment Requirements	$ 3,360,969			
Project Contingency, C	$ 213,334		(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)				
Total Plant Cost, D (DC + IC + C)	$ 1,635,562						
			Total Direct Annual Costs		$3,502,590		
Allowance for Funds During Constr., E	$ -					**Cost Efficiency:**	
Royalty Allowance,F	$ -					**\$/ton NO_X removed**	**$146,214**
Preproduction Costs, G	$ 32,711		**Indirect Annual Costs**				
Inventory Capital, H	$ 67,095		CRF	0.102			
Initial Catalyst and Chemicals, I	$ -		Total IDAC (CRF x TCI)		$ 176,751		
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)		**$ 1,735,369**	**TOTAL ANNUAL COST, TAC (DAC + IDAC)**		**$ 3,679,341**		

SNCR Design Parameters used for Estimation

Boiler #2 Max. Heat Input, Q_B = 84.6 MMBtu/hr

System Capacity Factor, CF_{total} = CF_{plant} x CF_{SNCR}

Capacity Factor, CF, a measure of the average annual use of the boiler in conjunction with the SNCR system.

$$CF_{plant} = \frac{FuelUsage_{annual}, lbs}{FuelUsage_{potential}, lbs}$$

$$CF_{Boiler\#2} = \frac{Actual_{2018}, MMBtu/hr}{Potential, MMBtu/hr}$$

Worst-Case Actual	84.6	MMBtu/hr
Potential	84.6	MMBtu/hr

CFBoiler2= 1.00

t_{SNCR} 365 days/yr

$$CF_{SNCR} = \frac{t_{SNCR}(days/yr)}{365(days/yr)}$$

CF_{SNCR}= 1.00

CF_{total}= 1.00

Uncontrolled NO_X, Stack NO_X and NO_X Removal Efficiency

NOx_{in}, (uncontrolled)= 0.16 lb/MMBtu (Potential, effective permit limit)

NOX Removal Efficiency, η_{NOx} = 45%

Normalized Stoichiometric Ratio, NSR (Equation 1.17 of SNCR manual)

$$NSR = \frac{\left[\left(\frac{2\ mol\ Urea}{mol\ NO_X}\right) \times NO_{X_{in}} + 0.7\right] \times \eta_{NO_x}}{NO_{X_{in}}}$$

NSR = 2.87

Estimating Reagent Consumption

Reagent Consumption Parameters:

ρ_{sol} =	9.5	Density of aqueous reagent solution (lb/gal) (For a 50% urea solution, as per page 1-38 of SNCR Manual)
$M_{reagent}$ =	60.06	Molecular weight of reagent (grams/mol Urea)
M_{NO2}=	46.01	Molecular weight of NO_2 (grams/mol NO_2)
SR_T=	2	Ratio of equivalent moles of NH_3 per mole of reagent (mols NH_3/mol Urea)
C_{sol} =	0.5	Concentration of aqueous reagent solution by weight (lb reagent/lb solution) (50% solution)

Reagent mass flow rate:

$$\dot{m}_{reagent} = \frac{NO_{X_{in}} \times Q_B \times \eta_{NOx} \times NSR \times M_{reagent}}{M_{NO_2} \times SR_T}$$ (Equation 1.18 of SNCR manual)

$\dot{m}_{reagent}$ = 11.4 lbs/hr

Aqueous reagent solution mass flow rate: (Equation 1.19 of SNCR manual)

$$\dot{m}_{sol} = \frac{\dot{m}_{reagent}}{C_{sol}}$$

$\dot{m}_{sol}$ = 22.8 lbs/hr

Solution volume flow rate: (Equation 1.20 of SNCR manual)

$$q_{sol} = \frac{\dot{m}_{sol}}{\rho_{sol}}$$

q_{sol} = 2.40 gph

Aqueous reagent solution storage:

$V_{tank} = q_{sol} \times t_{storage}$

$t_{storage}$ = 14.00 days (Assumption from pg. 1-39 in SNCR manual)

V_{tank} = 807.57 gallons

TOTAL CAPITAL INVESTMENT, TCI

Cost Year = 1998

equipment, direct and indirect installation costs, additional costs due to installation such as asbestos removal, costs for buildings and site preparation, offsite facilitites, land and working capital.

DC=	Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. This includes costs associated with field measurements, numberical modeling and system design. It also includes direct installation costs such as auxiliary equipment (e.g.ductwork, compressor), foundations and supports, handling and erection, electrical, piping, insulation and painting. In addition costs such as asbestos removal are included.
PEC=	Purchased Equipment Cost
IC=	Indirect Capital

Total Direct Capital Costs, DC:

$$DC = \frac{\$950}{\frac{MMBtu}{hr}} Q_B \left(\frac{MMBtu}{hr}\right) \left\{\frac{2375 \frac{MMBtu}{hr}}{Q_B \left(\frac{MMBtu}{hr}\right)}\right\}^{0.577} (0.66 + 0.85\eta_{NO_x})$$

DC (2022 \$) = \$ 1,214,838.19 (Chemical Engineering Plant Index difference applied to DC)

Indirect Capital Costs:

Total Indirect Installation Costs, IC (2022 \$) = \$ 242,968

=DC x (General Facilities % + Engineering and Home Office Fees % + Process Contingency %)

General Facilities % =	5%
Engineering and Home Office Fees % =	10%
Process Contingency % =	5%

Project Contingency, C =	\$	218,670.87	
=		15%	of DC + IC
Total Plant Cost, D =	\$	1,676,476.70	= DC + IC + C

Allowance for Funds During Construction, E =	$	-	(Assumed zero for SNCR)	
Royalty Allowance,F =	$	-	(Assumed zero for SNCR)	
Preproduction Costs, G =	$	33,529.53		
=		2%	of D + E	
Inventory Capital, H =	$	71,134.07	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)	
$Vol_{reagent}$ =		20,997	gal/yr	
$Cost_{reagent}$ =		3.39	$/gal	$/gallon (Mundi Price Index for September 2022, United States)
Initial Catalyst and Chemicals, I =	$	-	(Assumed zero for SNCR)	
Total Capital Investment, TCI =	$	1,781,140.30	= D + E + F + G + H + I	

TOTAL ANNUAL COSTS

TAC = Total Annual Cost
Includes: direct costs, indirect costs, and recovery credits.

DAC = Direct Annual Costs
Include: variable and semivariable costs.
Variable includes: purchase of reagent, utilities, and any additional fuel and ash disposal resulting from the operation of the
Semivariable include: operating and supervisory labor and maintenance.

$$DAC = \begin{pmatrix} Annual \\ Maintenance \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Reagent \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Electricity \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Water \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Fuel \\ Cost \end{pmatrix}$$

<u>Operating and Supervisory Labor:</u>
In general, no additional personnel is required to operate or maintain the SNCR equipment for large industrial facilities.

<u>Maintenance:</u>

1.5% of TCI
Maintenance = $ 26,717

Total operating time, $t_{op} = CF_{total}$ x 8760 hrs/yr 8760 hours (CF not used as max hours required for BART analysis)

Reagent Consumption (Urea):

$cost_{reagent}$		3.39	\$/gallon (Mundi Price Index for September 2022, United States)
Annual reagent cost =	\$	71,329	= q_{sol} x $cost_{reagent}$ x t_{op}

Utilities:

Power Consumption, P:

$$P = \frac{0.47 \times NOx_{in} \times NSR \times Q_B}{9.5}$$

NOx_{in}, (uncontrolled)=		0.160047281	lb/MMBtu
NSR (Normalized Stoichiometric Ratio):		2.87	
Q_B, boiler heat input=		84.6	MMBtu/hr
P =		2	kw
$Cost_{elec}$=		0.09	\$/kwh (September 2022, U.S. EIA statistics for Pennsylvania)
t_{op} =		8760	hours
Annual electricity cost = P x $Cost_{elect}$ x t_{op} =	\$	1,505	per kWh

Water Consumption:

$$q_{water} = \frac{\dot{m}_{sol}}{\rho_{water}}\left(\frac{C_{UreaSol_{stored}}}{C_{UreaSol_{inj}}} - 1\right)$$

For urea dilution from a 50% solution to a 10% solution q_{water} becomes:

$$q_{water} = \frac{4\dot{m}_{sol}}{\rho_{water}}$$

ρ_{water} =		8.345	lb/gal
q_{water} =		0.011	1,000 gallons/hour

Annual water cost = q_{water} x $Cost_{water}$ x t_{op} =

$Cost_{water}$ =		15.05	\$/1,000 gallons (2022 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for ≥10" Meter)
	\$	1,441.95	

Additional Fuel Consumption:

Because the water from the urea solution evaporates in the boiler, the boiler efficiency decreases. Consequently, more fuel needs to be burned to maintain the required steam flow.
Assumptions:

- Urea is injected at at 10% solution
- Heat of vaporization of water is 900 Btu/lb

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) = \frac{900\left(\frac{Btu}{lb}\right)}{10^6\left(\frac{Btu}{MMBtu}\right)} \times \dot{m}_{reagent}\left(\frac{lb}{hr}\right) \times 9$$

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) = 0.0924$$

Annual cost for additional fuel:

Additional fuel required:

Natural gas	0.09239	MMBtu/hr

Total cost associated with additional fuel usage:

Natural gas cost	9.44	$/MMBtu	(left as conservatively low value; current price is 17.29)
	$ 7,640.12	$/yr	
Total Natural gas:	$ 7,640.12		
Additional Energy Requirement =	$ 3,576,071	(Additional heating of exhaust gas required for SNCR operations.)	
Total DAC =	$ 3,684,704.44		

Indirect Annual Costs:

Indirect Annual Cost, IDAC = CRF x TCI
CRF = Capital Recovery Factor,

$$CRF = \frac{i(1+i)^n}{(1+i)^n} - 1$$

Interest rate,i =	8.00%	Prior Site-Specific Interest Rate Used in 4-Factor Analysis and BART Evaluation (Conservatively Low)
Economic life of SNCR, n=	20	years
CRF =	0.10	

TCI = Total Capital Investment (2020 $) = $ 1,781,140.30

IDAC = $ 181,413.07

Total Annual Cost (2022 $):
Total Annual Cost, TAC = DAC + IDAC = $ 3,866,117.52

COMPANY: **United State Steel**
LOCATION: **Irvin**
Source: **Boiler #2**
NO_X Emission Control Option: **SNCR (45% Efficiency)**

Site Information

Utility Unit Costs

Electricity, $/kwh	**0.09**
Interest Rate, %	**8.00%**
Water, $/1,000 gal	**15.05**
NG, $/MMBtu	**9.44**
Operating Labor, $/man-hr	**70.00**
Manhours per year	**547.5**
Sales Tax, % of FOB	**Included in DC**
Freight & Ins. to Site, % of FOB	**Included in DC**
Maintenance (Materials + Labor) % TCI	**1.5%**
General Facilities, % DC	**5%**
Engineering and Home Office Fees % DC	**10%**
Process Contingency % DC	**5%**
Project Contingency % DC+IC	**15%**
Preproduction Costs % of D+E	**2%**

Source Emission Information

Equipment Life, yr	**20.0**
Operating Hours Per Year	**8760**

Control Technology Information

Boiler Fuel Rating, mmBTU/hr	**85**
NOX Removal Efficiency, η_{NOx}	**45%**
Cost Year	**2022**

Incremental Utility Requirements

Electricity, kw	**2**
Reagent sol, gal/hr	**2.40**
Water, 1,000 gal/hr	**0.01**
NG, MMBtu/hr	**0.09239**

Reagent Volume, gallons	**20,997**
Reagent Cost, $/gallon	**3.39**

COMPANY: United State Steel
LOCATION: Irvin
Source: Boiler #2
NO_X Emission Control Option: SNCR (45% Efficiency)

TOTAL CAPITAL INVESTMENT

Total Direct Capital Cost, DC	$	1,214,838
Auxilliary Equipment (Heat Exchanger	$	-

Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.

Total Indirect Capital Costs:		
Indirect Capital, IC	$	242,968
Project Contingency, C	$	218,671
Total Plant Cost, D (DC + IC + C)	$	1,676,477
Allowance for Funds During Constr., E	$	-
Royalty Allowance,F	$	-
Preproduction Costs, G	$	33,530
Inventory Capital, H	$	71,134
Initial Catalyst and Chemicals, I	$	-
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)	**$**	**1,781,140**

TOTAL ANNUAL COST

Direct Annual Costs		
Operating & Supervisory Labor	$38,325	
Maintenance	$26,717	
Reagent Consumption	$71,329	
Utilities	$1,505	
Water Consumption	$1,442	
Add'l Fuel Usage (Process related)	$7,640.12	
Auxiliary Equipment Requirements	$ 3,576,071	
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)		
Total Direct Annual Costs		$3,723,029
Indirect Annual Costs		
CRF	0.102	
Total IDAC (CRF x TCI)		$ 181,413
TOTAL ANNUAL COST, TAC (DAC + IDAC)		**$ 3,904,443**

COST EFFECTIVENESS

NOX_{in}, lbs/MMBtu	0.160047281
Efficiency, %	45%
Boiler Heat Input, MMBtu/hr	84.6
Total Operating Time, hrs/yr	8760
NO_X removed, tpy	26.7
Cost Efficiency:	
\$/ton NO_X removed	**$146,341**

SNCR Costs for Furnaces

Source	Annualized Costs ($/yr)	NOx PTE (tpy)	Controlled Emissions (tpy)	Emissions Reduction (tpy)	Cost Effectiveness ($/ton)
Continuous Anneal Furnace	2,101,578	78.84	43.36	35.48	59,236

Heat Capacity Combustion Stack Gas

	Continuous Anneal Furn. Flue Gas Composition	Heat Capacity ($Btu/ft^3/^oF$)
H_2O	7.3%	0.0225
O_2	13.2%	0.0185
CO_2	4.0%	0.0260
N_2	75.5%	0.0185
Total	**100.0%**	**0.0191**

	Continuous Anneal Furn.	
Flow (1)	11,221	scfm
Flow	**6.73E+05**	**scfh**
$Temperature_{SNCR\ in}$ (1)	**465**	**F**
$Temperature_{SNCR\ out}$ (2)	**1650**	**F**
ΔT	**1184.974**	F
Heat Requirement	22.6	Btu/scf
Uncontrolled NOX (3)	18.00	lb / hr
NOX control eff'y (2)	45.0%	
NOX Removed	8.1	lb / hr
NOX Removed	1.20E-05	lb/scf flue gas
NOX from Natural Gas Combustion (4)	3.96E-06	lb/scf flue gas
Net NOX Reduction	8.07E-06	lb/scf flue gas
Natural Gas Eff'y	80.0%	
Natural Gas Req'd	28.3	Btu/scf flue gas
Natural Gas Req'd	2.83E-05	MMBtu/scf flue gas
Natural Gas Cost (5)	$11.03	/ MMbtu
Natural Gas Cost	$38.64	/lb NOX Removed
Annual Natural Gas Cost (6)	$1,839,690	

(1) Flowrate and temperatures values are based on SIP modeling (anneal furnace)
(2) SNCR temperature & efficiency from EPA Control Cost Manual, 6th Ed., NOX Controls, Fig 1.5. (Maximum uncontrolled NOX concentrati
(3) Utilizes the permit limits.
(4) Based on 140 lb NOX per MMscf natural gas
(5) EIA 2022 average NG prices for commercial consumers in 2022 (https://www.eia.gov/naturalgas/monthly/pdf/table_03.pdf)
(6) Annual NG Cost = $/MMBtu NG x MMBtu/scf flue gas x scf flue gas/hr x 8760 hrs/yr

SNCR Design Parameters used for Estimation

Cont. Annealing Furnace Max. Heat Input, Q_B = 45 MMBtu/hr

System Capacity Factor, CF_{total} = CF_{plant} x CF_{SNCR}

Capacity Factor, CF, a measure of the average annual use of the unit in conjunction with the SNCR system.

$$CF_{plant} = \frac{FuelUsage_{annual}, lbs}{FuelUsage_{potential}, lbs}$$

$$CF_{Boiler\#2} = \frac{Actual_{2018}, MMBtu/hr}{Potential, MMBtu/hr}$$

Worst-Case Actual	45.0	MMBtu/hr
Potential	45	MMBtu/hr

CF= 1.00

$$CF_{SNCR} = \frac{t_{SNCR}(days/yr)}{365(days/yr)}$$

t_{SNCR} 365 days/yr

CF_{SNCR}= 1.00

CF_{total}= 1.00

Uncontrolled NO_X, Stack NO_X and NO_X Removal Efficiency

NOx_{in}, (uncontrolled)= 0.40 lb/MMBtu (Potential, effective permit limit)

NOX Removal Efficiency, η_{NOx} = 45%

Normalized Stoichiometric Ratio, NSR (Equation 1.17 of SNCR manual)

$$NSR = \frac{\left[\left(\frac{2\ mol\ Urea}{mol\ NO_X}\right) \times NO_{X_{in}} + 0.7\right] \times \eta_{NO_x}}{NO_{X_{in}}}$$

NSR = 1.69

Estimating Reagent Consumption

Reagent Consumption Parameters:

ρ_{sol} =	9.5	Density of aqueous reagent solution (lb/gal) (For a 50% urea solution, as per page 1-38 of SNCR Manual)
$M_{reagent}$ =	60.06	Molecular weight of reagent (grams/mol Urea)
M_{NO2}=	46.01	Molecular weight of NO_2 (grams/mol NO_2)
SR_T=	2	Ratio of equivalent moles of NH_3 per mole of reagent (mols NH_3/mol Urea)
C_{sol} =	0.5	Concentration of aqueous reagent solution by weight (lb reagent/lb solution) (50% solution)

Reagent mass flow rate:

$$\dot{m}_{reagent} = \frac{NO_{X_{in}} \times Q_B \times \eta_{NOx} \times NSR \times M_{reagent}}{M_{NO_2} \times SR_T}$$ (Equation 1.18 of SNCR manual)

$\dot{m}_{reagent}$ = 8.9 lbs/hr

Aqueous reagent solution mass flow rate: (Equation 1.19 of SNCR manual)

$$\dot{m}_{sol} = \frac{\dot{m}_{reagent}}{C_{sol}}$$

$\dot{m}_{sol}$ = 17.8 lbs/hr

Solution volume flow rate: (Equation 1.20 of SNCR manual)

$$q_{sol} = \frac{\dot{m}_{sol}}{\rho_{sol}}$$

q_{sol} = 1.88 gph

Aqueous reagent solution storage:

$V_{tank} = q_{sol} \text{ x } t_{storage}$

$t_{storage}$ = 14.00 days (Assumption from pg. 1-39 in SNCR manual)

V_{tank} = 631.65 gallons

TOTAL CAPITAL INVESTMENT, TCI

Cost Year = 1998

equipment, direct and indirect installation costs, additional costs due to installation such as asbestos removal, costs for buildings and site preparation, offsite facilitites, land and working capital.

DC=	Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. This includes costs associated with field measurements, numberical modeling and system design. It also includes direct installation costs such as auxiliary equipment (e.g.ductwork, compressor), foundations and supports, handling and erection, electrical, piping, insulation and painting. In addition costs such as asbestos removal are included.
PEC=	Purchased Equipment Cost
IC=	Indirect Capital

Total Direct Capital Costs, DC:

$$DC = \frac{\$950}{\frac{MMBtu}{hr}} Q_B \left(\frac{MMBtu}{hr}\right) \left\{ \frac{2375 \frac{MMBtu}{hr}}{Q_B \left(\frac{MMBtu}{hr}\right)} \right\}^{0.577} \left(0.66 + 0.85\eta_{NO_X}\right)$$

DC (2022 $) = $ 930,142.88 (Chemical Engineering Plant Index difference applied to DC)

Indirect Capital Costs:

Total Indirect Installation Costs, IC (2022 $) = $ 186,029
=DC x (General Facilities % + Engineering and Home Office Fees % + Process Contingency %)

General Facilities % =	5%
Engineering and Home Office Fees % =	10%
Process Contingency % =	5%

Project Contingency, C =	$ 167,425.72	
=	15%	of DC + IC
Total Plant Cost, D =	$ 1,283,597.17	= DC + IC + C

Allowance for Funds During Construction, E =	$ -	(Assumed zero for SNCR)	
Royalty Allowance,F =	$ -	(Assumed zero for SNCR)	
Preproduction Costs, G =	$ 25,671.94		
=	2%	of D + E	
Inventory Capital, H =	$ 55,637.89	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)	
$Vol_{reagent}$ =	16,423	gal/yr	
$Cost_{reagent}$ =	3.39	$/gal	$/gallon (Mundi Price Index for September 2022, United States)
Initial Catalyst and Chemicals, I =	$ -	(Assumed zero for SNCR)	
Total Capital Investment, TCI =	$ 1,364,907.00	= D + E + F + G + H + I	

TOTAL ANNUAL COSTS

TAC = Total Annual Cost
Includes: direct costs, indirect costs, and recovery credits.

DAC = Direct Annual Costs
Include: variable and semivariable costs.
Variable includes: purchase of reagent, utilities, and any additional fuel and ash disposal resulting from the operation of the
Semivariable include: operating and supervisory labor and maintenance.

$$DAC = \begin{pmatrix} Annual \\ Maintenance \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Reagent \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Electricity \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Water \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Fuel \\ Cost \end{pmatrix}$$

<u>Operating and Supervisory Labor:</u>
In general, no additional personnel is required to operate or maintain the SNCR equipment for large industrial facilities.

<u>Maintenance:</u>

1.5% of TCI
Maintenance = $ 20,474

Total operating time, $t_{op} = CF_{total}$ x 8760 hrs/yr 8760 hours (CF not used as max hours required for BART analysis)

Reagent Consumption (Urea):

$cost_{reagent}$		3.39	\$/gallon (Mundi Price Index for September 2022, United States)
Annual reagent cost =	\$	55,791	$= q_{sol} \times cost_{reagent} \times t_{op}$

Utilities:

Power Consumption, P:

$$P = \frac{0.47 \times NOx_{in} \times NSR \times Q_B}{9.5}$$

NOx_{in}, (uncontrolled)=		0.4	lb/MMBtu
NSR (Normalized Stoichiometric Ratio):		1.69	
Q_B,heat input=		45	MMBtu/hr
P =		2	kw
$Cost_{elec}$ =		0.09	\$/kwh (September 2022, U.S. EIA statistics for Pennsylvania)
t_{op} =		8760	hours
Annual electricity cost = P x $Cost_{elect}$ x t_{op} =	\$	1,177	per kWh

Water Consumption:

$$q_{water} = \frac{\dot{m}_{sol}}{\rho_{water}}\left(\frac{C_{UreaSol_{stored}}}{C_{UreaSol_{inj}}} - 1\right)$$

For urea dilution from a 50% solution to a 10% solution q_{water} becomes:

$$q_{water} = \frac{4\dot{m}_{sol}}{\rho_{water}}$$

ρ_{water} =	8.345	lb/gal
q_{water} =	0.009	1,000 gallons/hour

Annual water cost = q_{water} x $Cost_{water}$ x t_{op} =

$Cost_{water}$ =		15.05	\$/1,000 gallons (2022 cost from Pittsburgh Water and Sewage Authority Published Rate Sheet for ≥10" Meter)
	\$	1,127.83	

Additional Fuel Consumption:

Because the water from the urea solution evaporates in the unit, the combustion unit efficiency decreases. Consequently, more fuel needs to be burned to maintain the required steam flow.

Assumptions:

- Urea is injected at at 10% solution
- Heat of vaporization of water is 900 Btu/lb

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) = \frac{900\left(\frac{Btu}{lb}\right)}{10^6\left(\frac{Btu}{MMBtu}\right)} \times \dot{m}_{reagent}\left(\frac{lb}{hr}\right) \times 9$$

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) = 0.0723$$

Annual cost for additional fuel:

Additional fuel required:

Natural gas	0.07226	MMBtu/hr

Total cost associated with additional fuel usage:

Natural gas cost	9.44	$/MMBtu	(left as conservatively low value; current price is 17.29)
	$ 5,975.76	$/yr	
Total Natural gas:	$ 5,975.76		
Additional Energy Requirement =	$ 1,839,690	(Additional heating of exhaust gas required for SNCR operations.)	
Total DAC =	$ 1,924,234.37		

Indirect Annual Costs:

Indirect Annual Cost, IDAC = CRF x TCI
CRF = Capital Recovery Factor,

$$CRF = \frac{i(1+i)^n}{(1+i)^n} - 1$$

Interest rate,i =	8.00%	Prior Site-Specific Interest Rate Used in 4-Factor Analysis and BART Evaluation (Conservatively Low)
Economic life of SNCR, n=	20	years
CRF =	0.10	

TCI = Total Capital Investment (2020 $) = $ 1,364,907.00

IDAC = $ 139,018.79

Total Annual Cost (2022 $):
Total Annual Cost, TAC = DAC + IDAC = $ 2,063,253.16

COMPANY: **United State Steel**
LOCATION: **Irvin**
Source: **Cont. Annealing Furnace**
NO_X Emission Control Option: **SNCR (45% Efficiency)**

Site Information

Utility Unit Costs	
Electricity, $/kwh	**0.09**
Interest Rate, %	**8.00%**
Water, $/1,000 gal	**15.05**
NG, $/MMBtu	**9.44**
Operating Labor, $/man-hr	**70.00**
Manhours per year	**547.5**
Sales Tax, % of FOB	**Included in DC**
Freight & Ins. to Site, % of FOB	**Included in DC**
Maintenance (Materials + Labor) % TCI	**1.5%**
General Facilities, % DC	**5%**
Engineering and Home Office Fees % DC	**10%**
Process Contingency % DC	**5%**
Project Contingency % DC+IC	**15%**
Preproduction Costs % of D+E	**2%**

Source Emission Information

Equipment Life, yr	**20.0**
Operating Hours Per Year	**8760**

Control Technology Information

Boiler Fuel Rating, mmBTU/hr	**45**
NOX Removal Efficiency, η_{NOx}	**45%**
Cost Year	**2022**
Incremental Utility Requirements	
Electricity, kw	**2**
Reagent sol, gal/hr	**1.88**
Water, 1,000 gal/hr	**0.01**
NG, MMBtu/hr	**0.07226**
Reagent Volume, gallons	**16,423**
Reagent Cost, $/gallon	**3.39**

COMPANY: United State Steel
LOCATION: Irvin
Source: Cont. Annealing Furnace
NO_X Emission Control Option: SNCR (45% Efficiency)

TOTAL CAPITAL INVESTMENT		
Total Direct Capital Cost, DC	$	930,143
Auxilliary Equipment (Heat Exchanger	$	-
Direct Capital costs includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. Cost for heat exchanger not included.		
Total Indirect Capital Costs:		
Indirect Capital, IC	$	186,029
Project Contingency, C	$	167,426
Total Plant Cost, D (DC + IC + C)	$	1,283,597
Allowance for Funds During Constr., E	$	-
Royalty Allowance,F	$	-
Preproduction Costs, G	$	25,672
Inventory Capital, H	$	55,638
Initial Catalyst and Chemicals, I	$	-
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)	**$**	**1,364,907**

TOTAL ANNUAL COST			
Direct Annual Costs			
Operating & Supervisory Labor	$38,325		
Maintenance	$20,474		
Reagent Consumption	$55,791		
Utilities	$1,177		
Water Consumption	$1,128		
Add'l Fuel Usage (Process related)	$5,975.76		
Auxiliary Equipment Requirements	$ 1,839,690		
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)			
Total Direct Annual Costs			$1,962,559
Indirect Annual Costs			
CRF	0.102		
Total IDAC (CRF x TCI)		$	139,019
TOTAL ANNUAL COST, TAC (DAC + IDAC)		**$**	**2,101,578**

COST EFFECTIVENESS	
NOX_{in}, lbs/MMBtu	0.4
Efficiency, %	45%
Boiler Heat Input, MMBtu/hr	45
Total Operating Time, hrs/yr	8760
NO_X removed, tpy	35.5
Cost Efficiency:	
\$/ton NO_X removed	**$59,236**

LNB Costs for Furnaces

Source	Annualized Costs ($/yr)	NOx PTE (tpy)	Controlled Emissions (tpy)	Emissions Reduction (tpy)	Cost Effectiveness ($/ton)
HSM Furnace (Each)	1,364,984	110.25	91.98	18.27	74,712
Continuous Anneal Furnace	1,364,984	78.84	29.57	49.28	27,701

COMPANY: United States Steel
LOCATION: Irvin
Source: Hot Strip Mill Furnace (Each)
NOX Emission Control Option: Low NOx Burners

Site Information		Source Emission Information		Control Technology Information	
Utility Unit Costs[1]					
Electricity, $/kwh	**0.09**	Equipment Life, yr	**10.0**	Furance Fuel Rating, mmBTU/hr	**140**
Interest Rate, %	**8.00%**	Operating Hours Per Year	**8760**	NOX Removal Efficiency, η_{NOx}	**17%**
Operating Costs				Cost Year	**2022**
Operating Labor, $/man-hr	**70**	Direct Installation			
Manhours per year	**0**	Foundations and supports	**4%**	Incremental Utility Requirement	
Maintenance (Materials + Labor) % TCI	**1%**	Handling and erection	**50%**	Additional fan Electricity, kw	**35**
Property Tax % of TCI	**1%**	Electrical	**8%**		
Insurance, % of TCI	**1%**	Piping	**1%**		
Administration, % of TCI	**1%**	Insulation	**7%**	Indirect Costs	
Overhead, % Labor & Mainteance	**60%**	Painting	**4%**	Construction and Field, % DC	**10%**
		Building preparation	**0%**	Engineering and Home Office Fees % DC	**20%**
Project Contingency % DC+IC	**20%**	Total Installation	**74%**	Construction Fee % DC	**10%**
				Performance Test, % DC	**1%**
				Startup, % DC	**2%**
Direct Costs				Total Indirect	**43%**
Sales Tax, % of FOB	**7%**				
Freight & Ins. to Site, % of FOB	**5%**				
Instrumentation	**10%**				

Costing elements based upon the 1997 EPA Alternative Control Techniquests (ACT) document for "NOx Controls for Instituional, Commecial and Industrial (ICI) Boilers," Section 6 for natural gas firing and OAQPS Cost Manual 5th Ed.
1 - USS specific rates for utilities, interest and labor.
2 - Equipment life based upon facility experience and history (consistent with RACT II)
3 - Post-Control NOx emission rates based upon actual USS Granite City Limits for the same type of burners and same type of sources.

COMPANY: United States Steel
LOCATION: Irvin
Source: Hot Strip Mill Furnace (Each)
NOX Emission Control Option: Low NOx Burners

TOTAL CAPITAL INVESTMENT		
Total Direct Capital Cost[1], DC		
Vendor Quoted Cost for Burners Only	$ 793,478	
Upgrade to meet NFPA Requirements[1]	$ 387,600	
CEMS and PLC Instrumentation[1]	$ 618,715	
Additional Combustion air fans	$ 90,000	
Refractory Replacement	$ 75,000	
Total Capital	$ 1,964,793	
Sales Tax	$ 137,536	
Freight & Ins. to Site	$ 98,240	
Direct Costs DC	$ 3,149,398	
Total Indirect Capital Costs:		
Indirect Capital, IC	$ 1,354,241	
Project Contingency, C	$ 900,728	
Total Plant Cost, D (DC + IC + C)	$ 5,404,368	
Direct Installation E	$ 1,453,947	
Royalty Allowance,F	$ -	
Preproduction Costs, G	$ -	
Inventory Capital, H	$ -	
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H)		**$ 6,858,315**

TOTAL ANNUAL COST		
Direct Annual Costs		
Operating & Supervisory Labor	$ -	
Maintenance	$ 68,583	
Reagent Consumption	$ -	
Utilities	$ 27,410	
Auxilliary Equipment Requirements	$ -	
(Auxillary Heating Costs)	$ -	
Total Direct Annual Costs		$ 95,993
Indirect Annual Costs		
Overhead	$ 41,150	
Property Tax	$ 68,583	
Insurance	$ 68,583	
Adminstration charges	$ 68,583	
		$ 246,899
Capital Recovery, CRF	0.149	
IDAC (CRF x TCI)		$ 1,022,091
TOTAL ANNUAL COST, TAC		**$ 1,364,984**

COST EFFECTIVENESS	
$NOx_{in\ Potential}$, lbs/MMBtu	0.18
Emissions After Control[3] lbs/MM	0.15
Efficiency, %	17%
Heat Input, MMBtu/hr	140
Total Operating Time, hrs/yr	8760
NO_X removed, tpy	18
Cost Efficiency:	
\$/ton NO_X removed	**$ 74,734**

Notes:
1 - Vendor quote for same setup and requirements for similar reheat furnaces at USS Granite City facility. Direct costs updated to reflect current CEPCI compared to prior analysis (2014).
2 - Estimates based upon knowledge of the process and vendor requirements for upgrade.
3 - Post-control NOx emission rates based upon actual USS Granite City Limits for the same type of burners and same type of sources.

COMPANY: United States Steel
LOCATION: Irvin
Source: Continuous Annealing Furnace
NOX Emission Control Option: Low NOx Burners

Site Information		**Source Emission Information**		**Control Technology Information**	
Utility Unit Costs[1]					
Electricity, $/kwh	**0.09**	Equipment Life, yr	**10.0**	Furnace Fuel Rating, mmBTU/hr	**45**
Interest Rate, %	**8.00%**	Operating Hours Per Year	**8760**	NOX Removal Efficiency, η_{NOx}	**63%**
Operating Costs				Cost Year	**2022**
Operating Labor, $/man-hr	**70**	Direct Installation			
Manhours per year	**0**	Foundations and supports	**4%**	Incremental Utility Requirement	
Maintenance (Materials + Labor) % TCI	**1%**	Handling and erection	**50%**	Additional fan Electricity, kw	**35**
Property Tax % of TCI	**1%**	Electrical	**8%**		
Insurance, % of TCI	**1%**	Piping	**1%**		
Administration, % of TCI	**1%**	Insulation	**7%**	Indirect Costs	
Overhead, % Labor & Mainteance	**60%**	Painting	**4%**	Construction and Field, % DC	**10%**
		Building preparation	**0%**	Engineering and Home Office Fees % DC	**20%**
Project Contingency % DC+IC	**20%**	Total Installation	**74%**	Construction Fee % DC	**10%**
				Performance Test, % DC	**1%**
				Startup, % DC	**2%**
Direct Costs				Total Indirect	**43%**
Sales Tax, % of FOB	**7%**				
Freight & Ins. to Site, % of FOB	**5%**				
Instrumentation	**10%**				

Costing elements based upon the 1997 EPA Alternative Control Techniquests (ACT) document for "NOx Controls for Instituional, Commecial and Industrial (ICI) Boilers," Section 6 foı natural gas firing and OAQPS Cost Manual 5th Ed.

1 - U. S. Steel specific rates for utilities, interest and labor.

2 - Equipment life based upon facility experience and history.

3 - Post-control NOx emission rates based on assumed same level of performance as HSM furnace evaluation.

COMPANY: United States Steel
LOCATION: Irvin
Source: Continuous Annealing Furnace
NOX Emission Control Option: Low NOx Burners

TOTAL CAPITAL INVESTMENT			TOTAL ANNUAL COST			COST EFFECTIVENESS		
Total Direct Capital Cost[1], DC			**Direct Annual Costs**			$NOx_{in\ Potential}$, lbs/MMBtu		0.40
						Emissions After Control[1]		
Vendor Quoted Cost for Burners Only	$ 793,478		Operating & Supervisory Labor	$ -		lbs/MMbtu		0.15
Upgrade to meet NFPA Requirements[1]	$ 387,600		Maintenance	$ 68,583		Efficiency, %		63%
CEMS and PLC Instrumentation[1]	$ 618,715		Reagent Consumption	$ -		Heat Input, MMBtu/hr		45
Additional Combustion air fans	$ 90,000		Utilities	$ 27,410		Total Operating Time, hrs/yr		8760
Refractory Replacement	$ 75,000							
Total Capital	$ 1,964,793		Auxilliary Equipment Requirements	$ -		NO_X removed, tpy		49
Sales Tax	$ 137,536							
Freight & Ins. to Site	$ 98,240		(Auxillary Heating Costs)	$ -				
Direct Costs DC	$ 3,149,398							
Total Indirect Capital Costs:			Total Direct Annual Costs		$ 95,993			
Indirect Capital, IC	$ 1,354,241							
Project Contingency, C	$ 900,728		**Indirect Annual Costs**			**Cost Efficiency:**		
Total Plant Cost, D (DC + IC + C)	$ 5,404,368		Overhead	$ 41,150		**\$/ton NO_X removed**	**$**	**27,701**
			Property Tax	$ 68,583				
Direct Installation E	$ 1,453,947		Insurance	$ 68,583				
			Adminstration charges	$ 68,583				
Royalty Allowance,F	$ -				$ 246,899			
Preproduction Costs, G	$ -		Capital Recovery, CRF	0.149				
Inventory Capital, H	$ -		IDAC (CRF x TCI)		$ 1,022,091			
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H)		**$ 6,858,315**	**TOTAL ANNUAL COST, TAC**		**$ 1,364,984**			

Notes:

1 - Cost estimates and NOx emission rates based upon burner vendor for HSM furnace. DC updated based on current CEPCI compared to 2014. Costs are conservatively low since the HSM reheat furnace has 20 burners and the CA furance has 150 burners (i.e., more burners to replace in this scenario).