United States Steel Corporation
Mon Valley Works

Kurt Barshick
General Manager
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 – Clairton 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 - Clairton 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 Mike Dzurinko at (412) 233-1467 or mdzurinko@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
M. Dzurinko

PENNSYLVANIA RACT III

NOTIFICATION OF COMPLIANCE STATUS & ALTERNATIVE RACT PROPOSAL

United States Steel Corporation / Clairton Plant

Prepared By:

TRINITY CONSULTANTS
4500 Brooktree Rd.
Suite 310
Wexford, PA 15090
724.935.2611

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1. INTRODUCTION

United States Steel Corporation (U. S. Steel) owns and operates a by-products recovery coke plant in Clairton, Pennsylvania known as the Clairton Plant. The Clairton Plant operates under federally enforceable Title V Operating Permit (TVOP) No. 0052-OP22.[1] The Clairton 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. 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 Clairton Plant is subject to certain provisions of this regulation including presumptive RACT, alternative RACT, 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).

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 Clairton Plant currently operates ten (10) coke batteries and produces approximately 13,000 tons of coke per day from the destructive distillation (carbonization) of more than 18,000 tons of coal. During the carbonization process, coke oven gas is produced. The volatile products of coal contained in the coke oven gas are recovered in the by-products plant. In addition to the coke oven gas, daily production of these by-products include crude coal tar as well as light oil.

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 are those facilities which are a major source of NO_X and/or VOC that commenced operation on or before August 3, 2018. The Clairton Plant is located in Allegheny County where the NO_X and VOC major source thresholds are 100 and 50 tons per year (tpy), respectively, potential to emit (PTE). As a major source of both pollutants, the Clairton 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. Appendix A provides supporting calculations demonstrating potential to emit less than 1.0 tpy for each of these sources as required under §129.115(a)(7)(ii). Table 1-1 identifies the sources for which U. S. Steel has claimed this exemption.

RACT is defined in Article XXI §2101.20 as:

[1] The Title V permit was reissued during the latter portions of conducting this RACT evaluation.

"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 existing VOC standards in Article XXI (e.g., §2105.15, etc.)[2].For example, cold cleaning operations are subject to §2105.15, and fuel and other miscellaneous hydrocarbon storage tanks 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 non-exempt 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 option is summarized in the following table. All sources identified in the table are located at the coke plant.

Table 1-1. RACT III Applicability for Clairton Plant

Source ID	Source Description	NOX RACT Status	VOC RACT Status
P001	Coke Battery No. 1; 517,935 tpy coal charge	Alternative Proposal	Alternative Proposal
P002	Coke Battery No. 2; 517,935 tpy coal charge	Alternative Proposal	Alternative Proposal
P003	Coke Battery No. 3; 517,935 tpy coal charge	Alternative Proposal	Alternative Proposal
P007	Coke Battery No. 13; 545,675 tpy coal charge	Alternative Proposal	Alternative Proposal
P008	Coke Battery No. 14; 545,675 tpy coal charge	Alternative Proposal	Alternative Proposal
P009	Coke Battery No. 15; 545,675 tpy coal charge	Alternative Proposal	Alternative Proposal
P010	Coke Battery No. 19; 1,002,290 tpy coal charge	Alternative Proposal	Alternative Proposal
P011	Coke Battery No. 20; 1,002,290 tpy coal charge	Alternative Proposal	Alternative Proposal
P012	Coke Battery B; 1,491,025 tpy coal charge	Alternative Proposal	Alternative Proposal

[2] 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
P013	Quench Tower No. 1	Presumptive	Alternative Proposal
P015	Quench Tower No. 5	Presumptive	Alternative Proposal
P016	Quench Tower No. 7	Presumptive	Alternative Proposal
P017	Quench Tower B	Presumptive	Alternative Proposal
P019	Desulfurization Plant	Presumptive	Alternative Proposal
P021	Coke By-Product Recovery Plant	Not Applicable (N/A)	Presumptive
P044a	Light Oil Barge Loading	N/A	Alternative Proposal
P044b	Light Oil Truck Loading	N/A	Exempt (PTE is 0.6 tpy)[3]
N/A	Coal Crude Tar Process Tank and Working Losses	N/A	Exempt (PTE is 0.09 tpy)[4]
P044d	Coal Crude Tar Loading	N/A	Alternative Proposal
B001	Boiler No. 1 (Babcock & Wilcox)	Alternative Proposal	Presumptive
B002	Boiler No. 2 (Combustion Engineering)	Alternative Proposal	Presumptive
B005	R1 Boiler (Riley Stoker)	Alternative Proposal	Presumptive
B006	R2 Boiler (Riley Stoker)	Alternative Proposal	Presumptive
B007	T1 Boiler (Erie City Zurn)	Alternative Proposal	Presumptive
B008	T2 Boiler (Erie City Zurn)	Alternative Proposal	Presumptive
B010	Ammonia Flare	Presumptive	Presumptive
G001	Misc. Fugitive Emissions (Abrasive blasting of coke oven doors)	N/A	Exempt (PTE is 0.23 tpy)[5]
P046	Coke Oven Battery C; 1,379,059 tpy coal charge	Alternative Proposal	Alternative Proposal
P047	C Battery Quench Tower	Presumptive	Alternative Proposal
P051	5A Quench Tower	Presumptive	Alternative Proposal
P052	7A Quench Tower	Presumptive	Alternative Proposal
N/A	Misc. Space Heaters	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 Clairton Plant:

[3] Per Table V-A.1 of Installation Permit 0052-I016 (August 2, 2017).

[4] Per Table V-A.1 of Installation Permit 0052-I015 (March 1, 2017).

[5] Consistent with Title V renewal calculations, abrasive VOC computed based on VOC content of abrasive (10% glycol ethers per SDS) and potential usage of 4,653 lbs/yr.

- Combustion units: §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) [relative to VOC emissions]; 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(c)(1) &(c)(2)

RACT III includes presumptive requirements for a NOx 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 Clairton Plant do not fall under another presumptive source category and have PTE meeting this criteria.

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 Clairton Plant are listed below.

Table 1-2. Presumptive – NO_x PTE <5 tpy and/or VOC <2.7 tpy

Source ID	Source Description	NOx PTE (tpy)	VOC PTE (tpy)
P013	Quench Tower No. 1	1.55	N/A – See Alternative RACT Proposal
P015	Quench Tower No. 5	1.88	N/A – See Alternative RACT Proposal
P016	Quench Tower No. 7	1.70	N/A – See Alternative RACT Proposal
P017	Quench Tower B	2.89	N/A – See Alternative RACT Proposal
P019	Desulfurization Plant	3.68	N/A – See Alternative RACT Proposal
P047	C Battery Quench Tower	2.77	N/A – See Alternative RACT Proposal
P051	5A Quench Tower	1.88	N/A – See Alternative RACT Proposal
P052	7A Quench Tower	1.70	N/A – See Alternative RACT Proposal

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). With respect to these provisions, only the miscellaneous space heaters at the plant meet the definition of combustion sources that 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.

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 Clairton Plant are any such flares at the site, including the ammonia flare (B010).

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.*

For the Clairton Plant, this provision applies to VOC emissions from the boilers as they are classified as "combustion units" in the rule. These sources include Source IDs, B001 – B008.

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 Clairton Plant which require alternative RACT proposals, along with the qualifying criteria, are summarized in the following table.

Table 1-3. Alternative (Case-by-Case) RACT III

Source ID	Source Description	Status
P001	Coke Battery No. 1	No Presumptive Category (NO_X > 5 tpy; VOC > 2.7 tpy);
P002	Coke Battery No. 2	No Presumptive Category (NO_X > 5 tpy; VOC > 2.7 tpy);
P003	Coke Battery No. 3	No Presumptive Category (NO_X > 5 tpy; VOC > 2.7 tpy);
P007	Coke Battery No. 13	No Presumptive Category (NO_X > 5 tpy; VOC > 2.7 tpy)
P008	Coke Battery No. 14	No Presumptive Category (NO_X > 5 tpy; VOC > 2.7 tpy)
P009	Coke Battery No. 15	No Presumptive Category (NO_X > 5 tpy; VOC > 2.7 tpy)
P010	Coke Battery No. 19	No Presumptive Category (NO_X > 5 tpy; VOC > 2.7 tpy)
P011	Coke Battery No. 20	No Presumptive Category (NO_X > 5 tpy; VOC > 2.7 tpy)
P012	Coke Battery B	No Presumptive Category (NO_X > 5 tpy; VOC > 2.7 tpy)
P013	Quench Tower No. 1	No Presumptive Category (NO_X > 5 tpy; VOC > 2.7 tpy)
P015	Quench Tower No. 5	No Presumptive Category (NO_X > 5 tpy; VOC > 2.7 tpy)
P016	Quench Tower No. 7	No Presumptive Category (NO_X > 5 tpy; VOC > 2.7 tpy)
P017	Quench Tower B	No Presumptive Category (NO_X > 5 tpy; VOC > 2.7 tpy)
P019	Desulfurization Plant	No Presumptive Category (VOC > 2.7 tpy)
P021	Coke By-Product Recovery Plant	No Presumptive Category (VOC > 2.7 tpy)
P044a	Light Oil Barge Loading	No Presumptive Category (VOC > 2.7 tpy)
P044d	Coal Crude Tar Loading	No Presumptive Category (VOC > 2.7 tpy)
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)
B005	R1 Boiler	No Presumptive Category Based on Fuels (NO_X > 5 tpy)
B006	R2 Boiler	No Presumptive Category Based on Fuels (NO_X > 5 tpy)
B007	T1 Boiler	No Presumptive Category Based on Fuels (NO_X > 5 tpy)
B008	T2 Boiler	No Presumptive Category Based on Fuels (NO_X > 5 tpy)
P046	Coke Oven Battery C	No Presumptive Category (NO_X > 5 tpy; VOC > 2.7 tpy)
P047	C Battery Quench Tower	No Presumptive Category (VOC > 2.7 tpy)
P051	5A Quench Tower	No Presumptive Category (VOC > 2.7 tpy)
P052	7A Quench Tower	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)[6] 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 cost effectiveness tables in the appendix fulfills the requirement. The following sections of this document outline the proposed for and conclusions from the alternative RACT III proposals.

2-001, January 2002, as amended.

2. ALTERNATIVE RACT SOURCES

As noted in Section 1, there are several sources at the Clairton 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
Coke Oven Batteries	P001 – P003; P007-P012, P046: Batteries 1-3, 13-15, 19-20, B and C	NO_X and VOC
Quench Towers	P013, P015, P016, P017, P047, P051, P052: Quench Towers	VOC
Desulfurization Plant	P019: Desulf. Plant	VOC
Coke By-Product Recovery Plant	P021: Coke By-Products Plant	VOC
Boilers	B001 through B008: Multifuel plant boilers	NO_x
VOC Loading Operations	P044a and P044d: Light Oil Barge Loading and Coal Crude Tar Loading	VOC

3. ALTERNATIVE RACT ANALYSIS

This section of the report provides the detailed proposed alternative RACT III requirements for sources at the Clairton 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– Coke Oven Batteries

The Clairton Plant operations include several combustion sources 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. The first set of operations in this category are coke oven batteries.

When considering NO_x emissions from the Batteries, 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 a flame. 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 NOx control technologies technically feasible to install at coke oven battery sources. This analysis has been executed previously including during the RACT II process[7]. This RACT II analysis was reviewed and updated and determined to be representative under RACT III provisions as summarized below. In general, the conclusions apply to all coke batteries except "C" Battery, which is discussed separately due to the new technology when the Battery was constructed. In general, no new technologies were identified that could be retrofit into the current coke oven battery processes at Clairton.

For "C" Battery, NO_X emissions are controlled through the employment of a combination of the PROven® system, the removal of nitrogen containing compounds in the COG by the byproduct recovery system, and the staging of combustion air in the heating flues.

Table 3-1. Potentially Available NO_x Control Technologies for Coke Oven Batteries

Potentially Applicable NO_x Control Technologies
Low NOx Burners (LNB)/Ultra Low NOx Burners (ULNB) – Underfire Only

[7] ACHD Reasonable Available Control Technology (RACT II) Determination (April 24, 2020) and IP No. 0052-I020.

Flue Gas Recirculation (FGR) or Overfire Air (OFA) – Underfire Only
LNB + FGR or OFA – Underfire Only
Selective Non-Catalytic Reduction (SNCR) – Underfire Only
LNB+SNCR – Underfire Only
Regenerative Selective Catalytic Reduction (RSCR) – Underfire Only
Selective Catalytic Reduction – Underfire Only
Good Work Practices (Base Case)

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 coke oven batteries of the Clairton Plant. There are no new pollutant specific air cleaning devices or technologies since the RACT II evaluation and the only identified control technology options pertain to the underfire combustion stacks.

3.2.2.1 Low NOx Burners/Ultra Low NOx Burners

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.

3.2.2.2 Flue Gas Recirculation

FGR is the process of taking a portion of the flue gas from a combustion process and recirculating it back through a boiler or burner.

3.2.2.3 Selective Non-Catalytic Reduction

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. 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.

3.2.2.4 Regenerative Selective Catalytic Reduction

RSCR combines regenerative thermal oxidizer (RTO) and SCR technologies through use of a reactant injector, heat exchangers, and a valve manifold adapted to direct a substantially continuous gas stream through the heat exchangers and catalyst chamber in such a manner as to flow through the catalyst chamber in the same flow direction during each cycle of the system.

3.2.2.5 Selective Catalytic Reduction

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 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.

3.2.2.6 Good Work Practices

For C Battery, good work practices include maintaining and operating the PROven® system. For all other batteries, good work practices include compliance with the applicable portions of NESHAP Subpart CCCCC and Subpart L.

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.

3.2.3.1 Low NOx Burners/Ultra Low NOx Burners

LNB/ULNB technology is considered to be **not technically feasible** for controlling NO_X emissions from the coke battery underfire combustion stacks as these are direct fired heating systems with unique combustion design. Such technology is not applicable to the other non-combustion sources.

3.2.3.2 Flue Gas Recirculation

FGR is considered to be **not technically feasible** for controlling NO_X emissions from the coke battery underfire combustion stacks due to the large volume of gas that is handled and the existing design of the underfire system coupled with the fuel heat input values that are required. Such technology is not applicable to the other non-combustion sources.

3.2.3.3 Selective Non-Catalytic Reduction

There are no known applications, demonstrated or commercially operational, of SNCR to a coke oven battery. In addition, there appears to be no evidence indicating that this pairing of control technology and operations has ever been studied. SNCR requires both a sufficient exhaust temperature and enough residence time at that temperature to allow the injected ammonia to mix with the exhaust gas and allow the NO_X reduction reactions to come to completion. While it may be possible to construct a battery reheat system that elevates the exhaust gas temperature to the requisite SNCR temperature window and provide sufficient residence time for the NO_X reduction reactions, doing so would result in an overall reduction in thermal efficiency and would likely result in the generation of more emissions than would be reduced by the SNCR. SNCR technology is considered to be **not technically feasible** for controlling NO_X emissions from the coke battery with preheating of the exhaust gas.

3.2.3.4 Regenerative Selective Catalytic Reduction

RSCR has the ability to use the majority of heat which is lost to the stack, thus requiring significantly less additional fuel use than other reduction technologies. However, in discussion with vendors it has been found that it has mainly only been applied to biomass plants for smaller boiler applications. Extensive research and pilot testing would be needed before its performance could be determined for COG and larger boiler applications. RSCR technology is considered to be **not technically feasible** for controlling NO_X emissions from the coke oven batteries as it is not proven on coke batteries and rerouting of the exhaust gases (and associated ductwork and heat exchangers) would be too extensive.

3.2.3.5 Selective Catalytic Reduction

SCR technology is considered to be **not technically feasible** for controlling NO_X emissions from the coke battery underfire combustion stacks due to the large potential outlet temperature and volumetric flowrate changes.

3.2.3.6 Good Work Practices

Good work practices are already employed at the Clairton Plant. This is **technically feasible.**

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 no add-on control technologies that are considered technically feasible. Good operating practices is the remaining technology and is already employed at the Clairton Plant.

3.2.5 Step 4: Evaluate Most Effective Controls and Document Results

Even though U. S. Steel has determined SNCR to be technically infeasible, the company did evaluate the cost for SNCR on the coke battery combustion stacks. The costs shown have been conservatively calculated using potential-to-emit (rather than actual emissions, which are significantly lower in many cases) and only reflect the costs associated with reheating the exhaust to the temperature range required for SNCR (i.e., no equipment costs, etc.). It should be noted that the costs were calculated in accordance with EPA's Cost Control Manual algorithms The calculated cost per ton of NO_X removal for each unit is well above $3,750 per ton, making the implementation of additional controls (SNCR) **economically infeasible,** as well as not technically feasible for these sources. The detailed cost analyses are included in Appendix A. Good operating practices are already employed and as such no further economic evaluation was performed.

Table 3-2. SNCR Control Costs for Coke Oven Batteries

Emission Source ID	Source Description	SNCR Costs ($/ton of NO_X Removed)
P007	Battery 13	$45,679
P008	Battery 14	$67,252
P009	Battery 15	$57,583
P010	Battery 19	$24,150
P011	Battery 20	$24,778
P012	Battery B	$40,775
P046	Battery C	$64,715

3.2.6 Step 5: Select RACT

The analysis for RACT on the coke oven batteries shows that no control technology is technically feasible, nor is cost effective. As the analysis shows a prohibitive cost per ton of NO_X removed for the retrofit of SNCR, the only remaining control is good combustion practices. For Step 5, the Clairton Plant will continue to employ good combustion management, and good operating, practices as RACT for the sources listed above.

3.3 NO_X RACT Assessment for Combustion Units – Boilers

The Clairton Plant operations include several boilers that are not able to meet presumptive NO_X limits due to multi-fuel capabilities, and have potential NO_X emissions greater than 5 tpy. As a collective source type, the boilers at Clairton consist of the following: Boiler No. 1; Boiler No. 2; Boiler R1, Boiler R2; Boiler T1; and Boiler T2. The four smaller boilers (Boiler R1, R2, T1 and T2) are package boilers that typically operate when one of the two primary boilers (Boiler No. 1 and Boiler No. 2) are down.

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. **Error! Reference source not found.**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)
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. 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)

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)/ Ultra Low NO_X Burners (ULNBs)

Burner manufacturers have previously indicated that replacement burners for the multi-fuel combustion configuration at these boilers would not achieve a reduction in NO_x, based upon the actual emission rates that are currently being achieved as reflected from stack testing and CEMS. Vendors would not quote possible emissions reductions and therefore based on these considerations LNBs are **not technically feasible** for the boilers. LNB in combination with other technology such as FGR and OGA is also not applicable. Low excess air is already being achieved such that further air restriction has the potential to put out the flame and/or result in incomplete combustion resulting in potential CO, VOC and opacity emission increases.

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 also ensures proper operation and maintenance according to good engineering and air pollution control practices.

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 three (3) control technologies that are considered technically feasible: SCR, SNCR, and Good Combustion Practices. The ranking for the control technologies are as follows:

1. SCR (estimated at 80%)
2. SNCR (estimated at 45%)
3. Good Combustion Practices (Base Case)

3.3.5 Step 4: Evaluate Most Effective Controls and Document Results

U. S. Steel has evaluated the cost for installing SCR and SNCR on the six existing boilers. The costs shown have been conservatively calculated using potential-to-emit (rather than actual emissions, which are significantly lower in many cases; particularly the package boilers). 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 or SNCR) **economically infeasible** for these sources. The detailed cost analyses are included in Appendix A.

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

Emission Source ID	Source Description	SCR Costs ($/ton of NO_X Removed)	SNCR Costs ($/ton of NO_X Removed)
B001	Boiler No. 1 (Babcock & Wilcox)	$10,204	$45,622
B002	Boiler No. 2 (Combustion Engineering)	$12,760	$54,501
B005	R1 Boiler (Riley Stoker)	$7,663	$25,060
B006	R2 Boiler (Riley Stoker)	$7,663	$25,060
B007	T1 Boiler (Erie City Zurn)	$13,224	$50,527
B008	T2 Boiler (Erie City Zurn)	$11,556	$46,014

3.3.6 Step 5: Select RACT

As shown in Step 3 above, the top-down RACT analysis for the Clairton Plant boilers shows two add-on control technologies that are technically feasible. Further, the results of the cost analysis (Step 4) shows that installation of SCR or SNCR 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 Clairton Plant proposes to continue to employ good combustion management practices as RACT III for the sources listed above. Based on these practices, U. S. Steel proposes the following limitations for the boilers based on a 30-day rolling average:

- Boiler No. 1 – 0.48 lb/MMBtu;
- Boiler No. 2 – 0.37 lb/MMBtu;
- Boiler R1 – 0.31 lb/MMBtu;
- Boiler R2 – 0.31 lb/MMBtu;
- Boiler T1 – 0.31 lb/MMBtu; and
- Boiler T2 – 0.31 lb/MMBtu.

3.4 VOC RACT Assessment for Coke Batteries

This section addresses VOC RACT for the coke batteries. As noted in NESHAPs standard 40 CFR Part 63 Subpart L, reduction in VOC generation is the only effective means of reducing VOCs from Battery operations. The NESHAPs standard addresses good operating practices for coke oven batteries, and U. S. Steel is already required to operate the batteries in accordance with good engineering practices, based on the NESHAP and existing Title V operating permit.

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, a review of the RBLC, and other coke plant air permits, there are no control technologies available for VOC control at batteries. Good operating practices are the only available control option. These practices include installing, maintaining and operating the equipment in accordance with the manufacturer's specifications and with good operating practices. Clairton's standard operating procedures optimize the balance among oven wall protection. Clairton Works procedures optimize the balance among oven wall protection and repair, combustion stack emissions and minimizing excess air. The wall maintenance program must be maintained at a high level of efficiency to avoid localized overheating that would result from any large leaks into the heating flues. Lastly, operation with sufficient excess air is needed to assure complete combustion of the COG that can be subject to heating value variability.

The prior RACT II reasoning for the lack of available add-on control technologies remains valid and excerpts are included below for completeness:

> *VOC emissions associated with the exhaust gas from controlled pushing baghouses are very low (i.e., parts per billion). As an example, the estimated VOC emissions from the baghouse that controls emissions from the controlled pushing of Batteries #1, 2 and 3 combined at the Clairton plant was estimated to be 0.0006 lbs/hr in 2012. The baghouse exhaust gas flowrate was approximately 110,000 acfm, which results in a VOC concentration of approximately 5 ppb. The volumetric flowrates versus the VOC concentrations are too low to apply post controls, such as incineration or carbon absorption. Due to the low concentrations the control technologies are not effective in reducing emissions. EPA literature (i.e. "Control Technologies for Hazardous Air Pollutants", EPA625/6-86-014) and vendors have indicated that VOC concentrations below approximately 20 ppm could not be reduced consistently or to any given predicted concentration. Additionally, VOCs that remain as products of combustion are typically higher molecular weight and boiling point chemicals, thus, they are normally more difficult to control than lower boiling point chemicals. Vendors of these technologies will not guarantee their performance due to the low concentrations. For this reason, if it was identified that VOC concentrations of an exhaust were too low, VOC controls were not considered technically feasible.*
>
> *Collection of battery fugitive emissions would result in significantly large volumetric exhaust gas flowrates due to the design of capture systems (i.e., large side-draft or canopy hoods); therefore, concentrations of VOC will be very low and inconsistent as well. Significant modeling of thermal and plume dispersion effects from fugitive releases would have to be performed to identify the type, location and size of collection systems that would be needed to understand if the reasonable collection of fugitive VOCs is possible. Additionally, leaks / fugitives from coke batteries (i.e., doors, lids, off takes) are already controlled by the requirements of the Coke Battery NESHAPs (40 CFR Part 63 subparts L and CCCCC). Based on the fact that the NESHAPs requirements address the reduction in fugitive leaks from batteries, and the fact that collection of fugitive leaks from these processes is not reasonable (due to the vast sizing and volumetric flows that would be required of capture systems), the application of the NESHAPs for fugitive leak reduction is considered to be RACT.*

3.4.2 Review of Potentially Applicable VOC Control Technologies

As noted in regulatory development documentation, the reduction in VOC generation is the only effective means of reducing VOCs from Battery operations. The NESHAP Part 63, Subpart L standard addresses good operating practices for Coke Oven Batteries.

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. No add-on control technologies or VOC reduction techniques are technically feasible for VOC coke battery emissions.

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. The only control technology is good operating practices.

3.4.5 Step 4: Evaluate Most Effective Controls and Document Results

No further analysis is needed since the Clairton Plant already complies with good operating practices.

3.4.6 Step 5: Select RACT

U. S. Steel is already required to operate the batteries in accordance with good engineering practices, based on the applicable NESHAP requirements and existing conditions of the Title V operating permit and previously issued RACT Installation Permit. The practices comprise U. S. Steel's RACT control strategy for these sources.

3.5 VOC RACT Assessment for Quench Towers

At the end of the coke cycle, when most of the volatiles have been driven off the coal to make coke, hot coke is pushed from the battery into a quench car. The quench car transports the coke to a quench tower where it is deluged with water to cool the coke. As a source, the quench towers consist of the following: Quench Tower No. 1; Quench Tower No. 5; Quench Tower No. 7; Quench Tower B; Quench Tower C; 5A Quench Tower; and 7A Quench Tower.

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. Based on past RACT evaluations for the site, a review of the RBLC, and other coke plant air permits, there are no control technologies other than following 40 CFR 63 Subpart CCCCC design and work practices. The Subpart CCCCC requirements are largely focused on minimizing opacity and particulate matter, but these techniques will also effectively minimize VOC in a similar manner.

3.5.2 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 the quench towers.

3.5.2.1 Good Work Practices

To minimize emissions from this process, the facility's quench towers are subject to coke oven batteries NESHAP, Subpart CCCCC work practice standards (40 CFR 63.7295(b)). These work practices represent industry standards and are technically and economically feasible as the facility is already implementing it. The applicable requirements have been incorporated into the Title V operating permit and has also been referenced in the RACT II IP20. Good work practices may include, as already noted in the Title V permit, limiting VOC potential through equipping each quench tower with baffles such that no more than 5 percent of the cross-sectional area of the tower may be uncovered or open to the sky; washing the baffles in each quench tower once each day that the tower is used to quench coke, except as specified in the Title V operating permit; inspecting each quench tower monthly for damaged or missing baffles and blockage; and initiating repair or replacement of damaged or missing baffles within 30 days and complete as soon as practicable.

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 remaining technologies are then carried into Step 3. The technology identified in Step 2 is technically feasible (i.e., it is already in place).

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. Based on the analysis described above, there is only one (1) technology that is technically feasible for VOC control at the quench towers, good work practices. The control is already employed at the Clairton Plant.

3.5.5 Step 4: Evaluate Most Effective Controls and Document Results

Since the Clairton Plant already employs good work practices, this was assumed to be the base case for RACT. No further analysis was performed.

3.5.6 Step 5: Select RACT

The RACT control strategy for VOC control from the Quench Towers at the Clairton Plant will be to continue to employ the good work practices as required by NEESHAP, Subpart CCCCC work practice standard 63.7295(b) and the Title V operating permit.

3.6 VOC RACT Assessment for Desulfurization Plant

After the volatile products in the COG are removed, the COG is processed in the desulfurization plant to remove hydrogen sulfide (H_2S) and other sulfur compounds. Clairton employs two Claus Plants in the desulfurization plant, a primary plant and a backup in the event the primary Claus Plant is out of service. The Claus Plant converts the H_2S and other sulfur compounds in the COG to elemental sulfur. The Shell Claus Offgas Treatment (SCOT) Plant separates the gas from the Claus Plant into a concentrated hydrogen sulfide stream and acid offgas. The concentrated hydrogen sulfide stream is sent back to the Claus Plant for further sulfur removal and recovery. The acid offgas is combusted at the SCOT Plant (i.e., thermal oxidizer). Thermal oxidation is considered to be the most effective means of reducing VOCs. Since the emissions are already controlled by thermal oxidation, no additional controls were reviewed.

3.6.1 Step 1: Identify All Control Technologies for VOC

Step 1 in a top-down analysis is to identify all available control technologies. There have not been any technological advancements since the RACT II analysis was performed. The technologies identified during this evaluation were:

- Thermal oxidation (i.e., SCOT Plant; base case);
- Carbon adsorption;
- Catalytic oxidation;

- Condensation;
- Flaring;
- Scrubbing technologies; and
- Good operating practices.

Thermal oxidation and/or good operating practices are the only options identified through research.

3.6.2 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. During the RACT II process, ACHD identified all the technologies in Step 1 as feasible. However, many of the technologies identified in Step 1 have not been demonstrated at a coke plant. As discussed in Step 3, the Clairton Plant already employs the most effective control option identified in Step 1. Therefore, the feasibility of the other control devices is irrelevant.

3.6.3 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. The most effective, and demonstrated control is thermal oxidation. The other thermal destructive controls (e.g., flaring and catalytic oxidation) would be next most effective followed by carbon adsorption, condensation and scrubbing (absorption).

3.6.4 Step 4: Evaluate Most Effective Controls and Document Results

No further economic analysis was needed since the Clairton Plant already complies with good operating practices and utilizes thermal oxidation (i.e., most effective control) as per the Title V operating permit.

3.6.5 Step 5: Select RACT

The RACT control strategy for the Clairton Desulfurization Plant is continued use of thermal oxidation and good work practices. These good work practices are identified in RACT IP0052-I020b and include operating and maintaining the two Claus Plants, Vacuum Carbonate Unit (VCU), spare heat exchangers and spare pumps in the VCUs.

3.7 VOC RACT Assessment for By-Products Recovery Plant

During the coking process, approximately 225 million cubic feet of raw coke oven gas are produced each day. The gases evolved leave the oven through standpipes, pass into gooseneck ducts, and then into the gas collection main. Axial compressors are used to move the coke oven gases which are composed of water vapor, tar, light oils (primarily benzene, toluene and xylene), heavy hydrocarbons, and other chemical compounds. The raw COG exiting the ovens is shock cooled by spraying recycled flushing liquor in the gooseneck. This spray cools the gas and precipitates tar, condenses various vapors, and serves as the carry medium for the condensed compounds. Additional cooling of the gas in the final coolers precipitates most of the remaining tar. After leaving the final coolers, the gas carries approximately three-fourths of the ammonia and 95 percent of the light oil originally present in the raw coke oven gas. This gas enters the PhosAm Absorber where the ammonia is removed and further processing produces anhydrous ammonia. The remaining stream which contains light oil and other compounds is further processed to produce a light oil product for sale.

Emissions of volatile organics from storage tanks and other equipment in the by-products plant are controlled by a gas blanketing system. The carrier gas in the blanketing system is clean COG. Storage tank atmospheric vents and other equipment are connected to this blanketing system where the collected organic vapors are mixed with the coke oven gas. This coke oven gas is used as fuel for boilers, furnaces and other fuel burning equipment at the Clairton Plant and the Irvin and Edgar Thomson Plants. These combustion sources ultimately destroy VOCs captured by the blanketing system.

3.7.1 Step 1: Identify All Control Technologies for VOC

Step 1 in a top-down analysis is to identify all available control technologies. **Error! Reference source not found.** contains a list of the various technologies that have been identified for the control of VOC from the by-products recovery plant. U. S. Steel did not identify any new controls, or advancement in control technologies since the prior evaluation in RACT II. The process is already subject to extensive requirements identified in the Title V Permit.

Table 3-5. Potentially Available VOC Control Technologies for By-Products Recovery Plant

Potentially Applicable VOC Control Technologies
Gas Blanketing System
Good Work Practices

3.7.2 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 these sources.

3.7.2.1 Gas Blanketing System

Emissions from the by-products recovery plant can be controlled by a gas-blanketing system that captures volatile organic compounds that are released through storage tank vents and from other equipment. Other measures, such as seals on pumps, compressors, etc. also control the release of VOCs. VOCs captured in the blanket gas are ultimately destroyed when the blanketing gas (e.g., COG) is burned as a fuel downstream.

3.7.2.2 Good Work Practices

Good work practices may include installing, maintaining, and operating the source in accordance with the manufacturer's specifications and with good operating practices. Extensive work practices are also identified in 40 CFR 61 Subpart L and 40 CFR 61 Subpart V, including a prescriptive leak detection and repair program.

3.7.3 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).

3.7.4 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 the by-products recovery plant (i.e., gas blanketing system). This control is already employed at the Clairton Plant.

3.7.5 Step 4: Evaluate Most Effective Controls and Document Results

Since the Clairton Plant by-products recovery plant is already equipped with a gas blanketing system, and the site employs good work practices, this is assumed to be the base case for RACT. No further analysis is needed.

3.7.6 Step 5: Select RACT

The RACT control strategy for the Clairton Plant by-product recovery plant is continued use of the gas blanketing system and good work practices. The Clairton Plant will continue to employ the technology as required under 40 CFR 61 Subpart L and Subpart V.

3.8 VOC RACT Assessment for Light Oil Loading Operations

Light oil is loaded once a week into 400,000 gallon river transport barges. Light oil is pumped from the light oil storage tanks into the barge at a rate of 1,200 gpm. The vapors that are displaced by the light oil in the barge are removed by use of an eductor. The gas used to drive the eductor is 100 psig natural gas. The vapors from the barge combined with the natural gas are then routed to the downriver gas system.

The light oil barge loading facility is equipped with a vapor recovery system. VOC releases originating from the transfer of light oil are captured and directed to the plant gas handling system, with no release to the atmosphere. To point, actual emissions from the process during calendar year were estimated at 0.02 tpy VOC.

3.8.1 Step 1: Identify All Control Technologies for VOC

Step 1 in a top-down analysis is to identify all available control technologies. **Error! Reference source not found.** contains a list of the various technologies that have been identified for the control of VOC from the light oil barge loading.

Table 3-6. Potentially Available VOC Control Technologies for Light Oil Loading Operations

Potentially Applicable VOC Control Technologies
Vapor Recovery System
Thermal destruction device (e.g., vapor combustor)
Good Work Practices

3.8.2 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 these sources.

3.8.2.1 Vapor Recovery System

The vapor recovery system captures VOC releases originating from the transfer of light oil and directs releases to the plant gas handling system, with no release to the atmosphere.

3.8.2.2 Vapor Combustor

A vapor combustor, also referred to as an enclosed flare, is a combustion device used for the destruction of vapors from various services. Through combustion, the VOCs are converted into carbon dioxide, water vapor and small quantities of other compounds. This control, which was identified based on a review of EPA's RBLC database, was generally employed for chemicals with a vapor pressure >0.5 psia, which is consistent (i.e., compatible) with the vapor pressure of Clairton's light oil.

3.8.2.3 Good Work Practices

Good work practices may include installing, maintaining, and operating the source in accordance with the manufacturer's specifications and with good operating practices.

3.8.3 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. All technologies identified in Step 2 are technically feasible with vapor recovery systems and good work practices already in place.

3.8.4 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 are only two (2) add-on control technologies that are considered technically feasible for the light oil loading operation (i.e., vapor combustor and vapor recovery system). A vapor combustor can generally achieve a destruction efficiency of 99% of vapor routed to it. The vapor recovery system employed at the Clairton Plant minimizes emissions (i.e., no release to the atmosphere) as emissions are captured and directed to the plant gas handling systems. This is corroborated by the minimal actual emissions from this process that are reported each year. As such, the most effective control is the vapor recovery system followed by vapor combustor.

3.8.5 Step 4: Evaluate Most Effective Controls and Document Results

Since the Clairton Plant light oil loading operations are already equipped with a vapor recovery system (most effective control), and the site employs good work practices, this is assumed to be the base case for RACT. No further analysis is needed. It is also worth noting that the employed control measures have the least amount of environmental side-effects such as additional NO_x and $PM_{2.5}$ emissions that would be generated through comparable VOC reduction techniques.

3.8.6 Step 5: Select RACT

The RACT control strategy for the Clairton Plant light oil loading operations is continued use of the vapor recovery system and good work practices. The Clairton Plant will continue to employ the technology and work practices as required under 40 CFR 63 Subpart Y and the Title V permit.

3.9 VOC RACT Assessment for Coal Crude Tar Loading Operations

The Clairton Plant operates coal crude tar load-out facilities for both truck and railcar loading. Coal crude tar is pumped from the coal crude tar tanks into the tank truck or railcar up to 130,000 gallons per day.

3.9.1 Step 1: Identify All Control Technologies for VOC

Step 1 in a top-down analysis is to identify all available control technologies. **Error! Reference source not found.** contains a list of the various technologies that have been identified for the control of VOC from the coal crude tar loading. U. S. Steel did not identify any similar tar loading operations with control through a review of EPA's RBLC database.

Table 3-7. Potentially Available VOC Control Technologies for Coal Crude Tar Loading Operations

Potentially Applicable VOC Control Technologies
Thermal Oxidizer
Vapor Combustor
Vapor Recovery System
Vapor Balancing System
Good Work Practices

3.9.2 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 these sources.

3.9.2.1 Thermal Oxidizer

Thermal oxidation removes VOCs from a vapor stream after being collected by a fume exhaust hood. Through combustion, the VOCs are converted into carbon dioxide, water vapor and small quantities of other compounds. In thermal oxidation, the emission stream passes through a combustion chamber where a natural gas-fueled flame ignites the VOCs in the vapor stream.

3.9.2.2 Vapor Combustor

A vapor combustor, also referred to as an enclosed flare, is a combustion device used for the destruction of vapors from various services. Through combustion, the VOCs are converted into carbon dioxide, water vapor and small quantities of other compounds. The primary difference between a vapor combustor and thermal oxidizer is that the latter uses an electric blower to create an intense flame.

3.9.2.3 Vapor Recovery System

A vapor recovery system captures VOC releases originating from the transfer of coal crude tar and directs releases to the plant gas handling system, with no release to the atmosphere.

3.9.2.4 Vapor Balancing System

Stage I vapor balancing systems returns gasoline vapors displaced from the underground tank that is being filled to the tank truck cargo compartments being emptied, while Stage II systems conveys the vapors displaced from the vehicle fuel tank to the underground storage tank vapor space.

3.9.2.5 Good Work Practices

Good work practices may include installing, maintaining, and operating the source in accordance with the manufacturer's specifications and with good operating practices.

3.9.3 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.

3.9.3.1 Thermal Oxidizer

Despite most controls at similar loading operations being used on only those streams with a vapor pressure of 0.5 psia or greater, the thermal oxidizer is considered to be **technically feasible** for the coal crude tar loading operations at the Clairton Plant. Therefore, the cost-effectiveness is further considered in this proposal.

3.9.3.2 Vapor Combustor

Based on RBLC data, loading rack vapor combustors are feasible for volatile organic compounds with a vapor pressure greater than 0.5 psia. The vapor pressure of the coal crude tar at the Clairton Plant is 0.0967 psia, and therefore a vapor combustor is **technically infeasible**.

3.9.3.3 Vapor Recovery System

A vapor recovery system would take the vapor recovery from the loading of railcar and trucks and redeliver it back into the gas main, similar to a natural gas blanketing system. However, there is potential to create an explosive environment due to the excess oxygen that would be recovered into the gas main. Therefore, a vapor recovery system is **technically infeasible**.

3.9.3.4 Vapor Balancing System

Stage I vapor balancing systems returns gasoline vapors displaced from the underground tank that is being filled to the tank truck cargo compartments being emptied, while Stage II systems conveys the vapors displaced from the vehicle fuel tank to the underground storage tank vapor space. These vapor balancing systems are not the correct application because the Clairton Plant is filling tanker trucks from storage tanks. The coal crude tar tanks are under pressure (approx. 1" w.c.) for the NESHAP required recovery system. However, vapor balancing/recovery would push air into the coal crude tar tank which is natural gas blanketed, therefore, it is concluded that vapor balancing is **technically infeasible** for the coal crude tar loading operation.

3.9.3.5 Good Work Practices

Good work practices may include installing, maintaining, and operating the source in accordance with the manufacturer's specifications and with good operating practices. Good work practices are considered to be **technically feasible** for the coal crude tar loading operations.

3.9.4 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 two (2) control technologies that are considered technically feasible: Thermal Oxidizer and Good Work Practices. The ranking for the control technologies are as follows:

1. Thermal Oxidizer
2. Good Work Practices

3.9.5 Step 4: Evaluate Most Effective Controls and Document Results

U. S. Steel has evaluated the cost for installing a thermal oxidizer on the coal crude tar loading operation system. The costs shown have been conservatively calculated using potential-to-emit (rather than actual emissions). It should be noted that the costs were calculated in accordance with EPA’s control cost template spreadsheet for regenerative thermal oxidation. Site-specific and/or 2022 data from public resources (e.g., EIA) were used as inputs for the spreadsheet. Since benzene emissions are the primary VOC expected in the emissions exhaust that constituent was used to represent the inlet gas stream composition and the concentration was set based on the potential to emit of 6.07 tpy VOC. As shown in Appendix A, the calculated cost per ton of VOC removal is approximately $108,600, making implementation of a thermal oxidizer **economically infeasible** for this source.

3.9.6 Step 5: Select RACT

The RACT control strategy for the Clairton Plant coal crude tar loading operations is good work practices. The Clairton Plant will continue to employ work practices as required under Allegheny County Health Department Rules and Regulations Article XXI §2105.03.

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 subject to the alternative RACT III provisions.

4.1 Coke Oven Batteries

Emission Source ID(s):	P001, P002, P003, P007, P008, P009, P010, P011, P012, P046
Source Description(s):	Coke Oven Batteries No. 1 through 3, No. 13 through 15, 19, 20, B and C.
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 and Work Practices (See Sections 3 and 6 under applicable source IDs in Title V permit):

- Follow inspections, operations, and maintenance plans as per Title V permit.

Proposed Testing (See Section 2 under applicable source IDs in Title V permit):

- Perform testing on combustion stack in accordance with Title V Permit

Proposed Recordkeeping (See Section 4 under applicable source IDs in Title V permit):

- Records of inspections and work practices

Proposed Reporting (See Section 5 under applicable source IDs in Title V permit):

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

4.2 Quench Towers

Emission Source ID(s):	P013, P015, P016, P017, P047, P051, P052
Source Description(s):	Coke Battery Quench Towers No. 1, 5, 7, B, C, 5A and 7A
Description of RACT:	Case-by-case
	1. Maintain and operate quench towers in accordance with 40 CFR Part 63, Subpart CCCCC (and Title V Permit), including design and operation of equipment.

<u>Proposed Monitoring (see Section 3 under applicable source IDs in Title V permit):</u>

- Inspect quench towers monthly for damaged or missing baffles and blockage and initiate repair or replacement of damaged or missing baffles.

<u>Proposed Testing (see Section 2 under applicable source IDs in Title V permit):</u>

- As per TV permit

<u>Proposed Work Practices (see Section 6 under applicable source IDs in Title V permit):</u>

- Equipping each quench tower with baffles such that no more than 5 percent of the cross-sectional area of the tower may be uncovered or open to the sky
- Washing baffles
- Monthly inspections
- Repair or replacement of missing baffles with prescribed timeframe

<u>Proposed Recordkeeping (see Section 4 under applicable source IDs in Title V permit):</u>

- Records of inspections and repairs/replacements of baffles

<u>Proposed Reporting (see Section 5 under applicable source IDs in Title V permit):</u>

- 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, B005, B006, B007, B008
Source Description(s):	Boiler No. 1 – 760 MMBtu/hr COG and NG Boiler No. 2 – 481 MMBtu/hr COG and NG R1 Boiler – 229 MMBtu/hr COG and NG R2 Boiler – 229 MMBtu/hr COG and NG T1 Boiler – 156 MMBtu/hr COG and NG T2 Boiler – 156 MMBtu/hr COG and NG
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. 2. 30-day rolling average limitation on NO_x emissions: a. Boiler No. 1 – 0.48 lb/MMBtu; b. Boiler No. 2 – 0.37 lb/MMBtu; c. Boiler R1 – 0.31 lb/MMBtu; d. Boiler R2 – 0.31 lb/MMBtu; e. Boiler T1 – 0.31 lb/MMBtu; and f. Boiler T2 – 0.31 lb/MMBtu.

Proposed Monitoring (See IP0052-I020b):

> Use of NO_x CEMS for Boilers 1 and 2

Proposed Testing (See IP0052-I020b):

> Testing once every two years for Boilers R1, R2, T1 and T2

Proposed Work Practices (See IP0052-I020b):

> Properly operate and maintain according to good engineering and air pollution control practices by performing regular maintenance

Proposed Recordkeeping (See IP0052-I020b):

> Records of fuel usage, cold starts and maintenance

Proposed Reporting (See IP0052-I020b):

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

4.4 Desulfurization Plant

Emission Source ID(s):	P019
Source Description(s):	Desulfurization Plant
Description of RACT:	Case-by-case
	Good operating practices.

Proposed Monitoring:

> As per TV permit

Proposed Testing:

> As per TV permit

Proposed Work Practices (See IP0052-I020b):

> 1. Properly maintain two Claus Plants at the coke oven gas desulfurization plant. Each Claus Plant shall be capable of independently processing all of the coke oven gas produced by the coke plant at full production.

> 2. Operating and maintaining a Vacuum Carbonate Unit at all times that coke oven gas is being produced at the Clairton Works.

> 3. Maintaining in good working order spare heat exchangers in the Vacuum Carbonate Units at the Clairton Works coke oven gas desulfurization facility.

> 4. Maintaining in good working order spare pumps in the Vacuum Carbonate Units at the coke oven gas desulfurization facility.

Proposed Recordkeeping:

> As per TV permit

Proposed Reporting:

> Annual emissions reporting by March 15th of each year

> Semi-annual Title V monitoring report and Annual Title V compliance certification

4.5 Coke By-Product Recovery Plant

<table>
<tr><td>Emission Source ID(s):</td><td>P021</td></tr>
<tr><td>Source Description(s):</td><td>Coke By-Products Plant</td></tr>
<tr><td rowspan="2">Description of RACT:</td><td>Case-by-case</td></tr>
<tr><td>1. Use of COG blanketing system
2. Good operating practices including compliance with 40 CFR 61 Subpart L</td></tr>
<tr><td colspan="2">
<u>Proposed Monitoring (see Section 3 under P021 of Title V Permit)::</u>
> As per TV permit

<u>Proposed Testing (see Section 2 under P021 of Title V Permit):</u>
> As per TV permit

<u>Proposed Work Practices: (see Section 6 under P021 of Title V Permit)</u>
> At no time shall the permittee operate the by-products plant unless the clean coke oven gas blanketing system is being properly maintained and operated at all times while the plant process units blanketed by the system are emitting VOCs, with the exception of emergency or planned outages, repairs or maintenance.
> The permittee shall comply with each applicable emission limitation, work practice standard, and operation and maintenance requirement of 40 CFR Part 61, Subpart V.

<u>Proposed Recordkeeping (see Section 4 under P021 of Title V Permit):</u>
> As per TV permit (40 CFR 61 Subpart L and V requirements)

<u>Proposed Reporting (see Section 5 under P021 of Title V Permit:</u>
> Annual emissions reporting by March 15th of each year
> Semi-annual Title V monitoring report and Annual Title V compliance certification
</td></tr>
</table>

4.6 Light Oil Barge Loading

Emission Source ID(s):	P044a
Source Description(s):	Light Oil Barge Loading
Description of RACT:	Case-by-case
	1. Use of a vapor recovery system 2. Good operating practices including compliance with 40 CFR 63 Subpart Y

Proposed Monitoring: (see Section 3 under P044a of Title V permit)

> Annual Method 21 inspection

Proposed Testing:

> As per TV permit

Proposed Work Practices (see Section 6 under P044a of the Title V permit):

> Operate and maintain the light oil loading facility, and air pollution control equipment, in a manner consistent with safety and good operating practices to minimize emissions.

Proposed Recordkeeping (see Section 4 under P044a of the Title V permit):

> Records of vapor-tightness documentation
> Records of leak detection and repair

Proposed Reporting (see Section 5 under P044a of the Title V permit):

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

4.7 Coal Crude Tar Barge Loading

Emission Source ID(s):	P044d
Source Description(s):	Coal Crude Tar Barge Loading
Description of RACT:	Case-by-case
	Good operating practices.

Proposed Monitoring:

> As per Title V permit

Proposed Testing:

> As per Title V permit

Proposed Work Practices:

> Properly operate and maintain the loading equipment such that VOC is minimized

Proposed Recordkeeping:

> Keep records of type and quantities of crude tar loaded

Proposed Reporting :

> 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

SNCR Costs for Battery Combustion Stack - Reheat Costs Only

Source	Annualized Costs ($/yr)	NOx PTE (tpy)	Controlled Emissions (tpy)	Emissions Reduction (tpy)	Cost Effectiveness ($/ton)
Battery 13	4,856,197	236.25	129.94	106.31	45,679
Battery 14	6,233,340	205.97	113.28	92.69	67,252
Battery 15	6,632,283	255.95	140.77	115.18	57,583
Battery 19	12,984,149	1,194.77	657.12	537.65	24,150
Battery 20	13,321,928	1,194.77	657.12	537.65	24,778
Battery B	14,085,993	767.68	422.22	345.46	40,775
Battery C	16,215,298	556.81	306.25	250.56	64,715

Heat Capacity Battery Combustion Stack Gas

	No. 13 Combustion Stack		No. 14 Combustion Stack		No. 15 Combustion Stack		No. 19 Combustion Stack		No. 20 Combustion Stack		Battery B Combustion Stack		Battery C Combustion Stack	
	Flue Gas Composition	Heat Capacity (Btu/ft^3/ºF)	Flue Gas Composition	Heat Capacity (Btu/ft^3/ºF)	Flue Gas Composition	Heat Capacity (Btu/ft^3/ºF)	Flue Gas Composition	Heat Capacity (Btu/ft^3/ºF)	Flue Gas Composition	Heat Capacity (Btu/ft^3/ºF)	Flue Gas Composition	Heat Capacity (Btu/ft^3/ºF)	Flue Gas Composition	Heat Capacity (Btu/ft^3/ºF)
H_2O	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225
O_2	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185
CO_2	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260
N_2	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185
Total	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**

	No. 13 Combustion Stack	No. 14 Combustion Stack	No. 15 Combustion Stack	No. 19 Combustion Stack	No. 20 Combustion Stack	Battery B Combustion Stack	Battery C Combustion Stack
Flow (1)	31,522 scfm	39,888 scfm	43,291 scfm	83,867 scfm	84,776 scfm	83,023 scfm	103,416 scfm
Flow	**1.89E+06 scfh**	**2.39E+06 scfh**	**2.60E+06 scfh**	**5.03E+06 scfh**	**5.09E+06 scfh**	**4.98E+06 scfh**	**6.20E+06 scfh**
Temperature$_{SNCR\ in}$ (1)	**536.5 F**	**520.5 F**	**542.68 F**	**531 F**	**514.2 F**	**423.7 F**	**516.7 F**
Temperature$_{SNCR\ out}$ (2)	**1650 F**	**1650 F**	**1650 F**	**1650 F**	**1650 F**	**1650 F**	**1650 F**
ΔT	**1113.5** F	**1129.5** F	**1107.32** F	**1119** F	**1135.8** F	**1226.3** F	**1133.3** F
Heat Requirement	21.3 Btu/scf	21.6 Btu/scf	21.1 Btu/scf	21.4 Btu/scf	21.7 Btu/scf	23.4 Btu/scf	21.6 Btu/scf
Uncontrolled NOX (3)	54.0 lb / hr	47.1 lb / hr	58.5 lb / hr	273.0 lb / hr	273.0 lb / hr	175.6 lb / hr	139.2 lb / hr
NOX control eff'y (2)	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%
NOX Removed	24.3 lb / hr	21.2 lb / hr	26.3 lb / hr	122.8 lb / hr	122.8 lb / hr	79.0 lb / hr	62.6 lb / hr
NOX Removed	1.29E-05 lb/scf flue gas	8.86E-06 lb/scf flue gas	1.01E-05 lb/scf flue gas	2.44E-05 lb/scf flue gas	2.41E-05 lb/scf flue gas	1.59E-05 lb/scf flue gas	1.01E-05 lb/scf flue gas
NOX from Natural Gas Combustion (4)	3.72E-06 lb/scf flue gas	3.77E-06 lb/scf flue gas	3.70E-06 lb/scf flue gas	3.74E-06 lb/scf flue gas	3.79E-06 lb/scf flue gas	4.10E-06 lb/scf flue gas	3.79E-06 lb/scf flue gas
Net NOX Reduction	9.14E-06 lb/scf flue gas	5.09E-06 lb/scf flue gas	6.44E-06 lb/scf flue gas	2.07E-05 lb/scf flue gas	2.04E-05 lb/scf flue gas	1.18E-05 lb/scf flue gas	6.31E-06 lb/scf flue gas
Natural Gas Eff'y	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
Natural Gas Req'd	26.6 Btu/scf flue gas	27.0 Btu/scf flue gas	26.4 Btu/scf flue gas	26.7 Btu/scf flue gas	27.1 Btu/scf flue gas	29.3 Btu/scf flue gas	27.0 Btu/scf flue gas
Natural Gas Req'd	2.66E-05 MMBtu/scf flue gas	2.70E-05 MMBtu/scf flue gas	2.64E-05 MMBtu/scf flue gas	2.67E-05 MMBtu/scf flue gas	2.71E-05 MMBtu/scf flue gas	2.93E-05 MMBtu/scf flue gas	2.70E-05 MMBtu/scf flue gas
Natural Gas Cost (5)	$11.03 / MMbtu	$11.03 / MMbtu	$11.03 / MMbtu	$11.03 / MMbtu	$11.03 / MMbtu	$11.03 / MMbtu	$11.03 / MMbtu
Natural Gas Cost	$32.08 /lb NOX Removed	$58.44 /lb NOX Removed	$45.25 /lb NOX Removed	$14.25 /lb NOX Removed	$14.69 /lb NOX Removed	$27.44 /lb NOX Removed	$47.28 /lb NOX Removed
Annual Natural Gas Cost (6)	$4,856,197	$6,233,340	$6,632,283	$12,984,149	$13,321,928	$14,085,993	$16,215,298

(1) Average of the latest stack test data for flow and temperature.
(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.
(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

SCR Costs for Boilers

Source	Annualized Costs ($/yr)	NOx PTE (tpy)	Controlled Emissions (tpy)	Emissions Reduction (tpy)	Cost Effectiveness ($/ton)
Boiler 1	13,044,663	1,598.00	319.60	1,278.40	10,204
Boiler 2	7,962,064	780.00	156.00	624.00	12,760
R1 Boiler	1,906,125	310.94	62.19	248.75	7,663
R2 Boiler	1,906,125	310.94	62.19	248.752	7,663
T1 Boiler	2,240,947	211.82	42.36	169.456	13,224
T2 Boiler	1,958,225	211.82	42.36	169.46	11,556

Heat Capacity Boiler Combustion Stack Gas

	BOILER #2		BOILER #R1		BOILER #R2		BOILER #T1		BOILER #T2		BOILER #1	
	Flue Gas Composition	Heat Capacity ($Btu/ft^3/^oF$)	Flue Gas Composition	Heat Capacity ($Btu/ft^3/^oF$)	Flue Gas Composition	Heat Capacity ($Btu/ft^3/^oF$)	Flue Gas Composition	Heat Capacity ($Btu/ft^3/^oF$)	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	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225
O2	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185
CO2	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260
N2	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185
Total	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**

	BOILER #2		BOILER #R1		BOILER #R2		BOILER #T1		BOILER #T2		BOILER #1	
Flow (1)	95,225	scfm	16,405	scfm	16,405	scfm	23,544	scfm	22,403	scfm	165,377	scfm
Flow	**5.71E+06**	**scfh**	**9.84E+05**	**scfh**	**9.84E+05**	**scfh**	**1.41E+06**	**scfh**	**1.34E+06**	**scfh**	**9.92E+06**	**scfh**
$Temperature_{SCR\ in}$ (1)	**287.5**	**F**	**395.4**	**F**	**395.4**	**F**	**328.8**	**F**	**400.3**	**F**	**297.6**	**F**
$Temperature_{SCR\ out}$ (2)	**730**	**F**	**730**	**F**	**730**	**F**	**730**	**F**	**730**	**F**	**730**	**F**
ΔT	**442.5**	F	**334.6**	F	**334.6**	F	**401.2**	F	**329.7**	F	**432.4**	F
Heat Requirement	8.4	Btu/scf	6.4	Btu/scf	6.4	Btu/scf	7.7	Btu/scf	6.3	Btu/scf	8.3	Btu/scf
Natural Gas Eff'y	80.0%		80.0%		80.0%		80.0%		80.0%		80.0%	
Natural Gas Req'd	10.6	Btu / scf flue gas	8.0	Btu / scf flue gas	8.0	Btu / scf flue gas	9.6	Btu / scf flue gas	7.9	Btu / scf flue gas	10.3	Btu / scf flue gas
Natural Gas Req'd	1.06E-05	MMBtu/scf flue gas	7.99E-06	MMBtu/scf flue gas	7.99E-06	MMBtu/scf flue gas	9.57E-06	MMBtu/scf flue gas	7.87E-06	MMBtu/scf flue gas	1.03E-05	MMBtu/scf flue gas
Natural Gas Cost (4)	$11.03	/ MMbtu	$11.03	/ MMbtu	$11.03	/ MMbtu	$11.03	/ MMbtu	$11.03	/ MMbtu	$11.03	/ MMbtu
Max Hours of Operation	8,760	Hr/yr	8,760	Hr/yr	8,760	Hr/yr	8,760	Hr/yr	8,760	Hr/yr	8,760	Hr/yr
Annual Natural Gas Cost (5	$5,829,839		$759,442		$759,442		$1,306,873		$1,021,921		$9,893,572	

(1) Average of the latest stack test data for flow and temperature. R1 set equal to R2 stack test parameters (flowrate and temperature)

(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 = 760 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	760.0	MMBtu/hr
Potential	760	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)= 0.48 lb/MMBtu (Potential, 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, $q_{fluegas}$

$q_{fluegas}$ = 242,435 acfm - based on testing at boilers.

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

$Vol_{reactor}$ = 4848.7 ft^3

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

$Area_{reactor}$ = 1212.175 ft^2

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

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

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

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

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

$Vol_{catalyst} = Vol_{reactor}$ 4,849 ft^3 (Assumption)

SCR Reactor Dimensions

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

$A_{catalyst}$ = 252.5 ft^2

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

A_{SCR} = 290.4 ft^2

l_{scr} = 17.0 ft

w_{scr} = 17.0 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} =	0.48	lb/MMBtu
Q_B =	760	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
$\dot{m}_{reagent}$ =	113.4	lbs/hr

For ammonia,

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

C_{sol} =	19%		(Percent concentration of the aqueous reagent solution)
= $\dot{m}_{sol}$	597.0	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} =	79.7	gph	

Tank volume:

$Vol_{Tank} = q_{sol} \times t$

t =	14.0	days	(Common on site storage requirement, Section 2.3.13 of SCR manual)
Vol_{Tank} =	26795	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	Clairton PA is 902 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 $) = $16,389,499 (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 =	$	81,947		

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 =	$	393,373	= 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 =		425.6	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} =	$	333,306	(CCM SCR June 2019, Equation 2.61)
Additional Energy Requirement =	$	9,893,572	(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)
$Vol_{catalyst}$ =	$	4,849	ft^3
Catalyst Replacement Cost (2022 $)=	$	1,675,263.00	(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 = $ 570,959

Total DAC (2022 $)= $ 11,375,357

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 = $16,389,499

IDAC (2022 $) = $ 1,669,307

Total Annual Cost (2022 $):
Total Annual Cost, TAC = DAC + IDAC = $13,044,663.30

COMPANY: United States Steel
LOCATION: Clairton
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	**760**
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	**426**
Freight & Ins. to Site, % of FOB	**Included in DC**			Reagent sol, gal/hr	**79.7**
Maintenance (Materials + Labor) % TCI	**0.5%**			Catalyst operating life, hrs	**24,000**
				Reagent Volume, gallons/hr	**79.7**
				Reagent Cost, $/gallon	**0.56**

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

TOTAL CAPITAL INVESTMENT			**COST EFFECTIVENESS**	
TOTAL CAPITAL INVESTMENT, TCI		**$ 16,389,499**		
TOTAL ANNUAL COST			Efficiency, %	80%
			Boiler Heat Input, MMBtu/hr	760
Direct Annual Costs			Total Operating Time, hrs/yr	8,760
Operating & Supervisory Labor	$102,200			
Maintenance	$81,947		NO_X removed, tpy	1,278.4
Reagent Consumption	$393,373			
Utilities	$333,306			
Catalyst Replacement	$570,959			
Auxilliary Equipment Requirements	$9,893,572			
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SCR required temperature.)			**Cost Efficiency:**	
			$/ton NO_X removed	**$ 10,204**
Total Direct Annual Costs	$11,375,357			
Indirect Annual Costs				
CRF	0.10185			
IDAC (CRF x TCI)	$1,669,307			
TOTAL ANNUAL COST, TAC	**$13,044,663**			

SCR Design Parameters used for Estimation

Boiler #2 Max. Heat Input, Q_B = 481 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	481.0	MMBtu/hr
Potential	481	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)= 0.37 lb/MMBtu (Potential, 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, $q_{fluegas}$

$q_{fluegas}$ = 138,574 acfm - based on testing at boilers.

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

$Vol_{reactor}$ = 2771.48 ft^3

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

$Area_{reactor}$ = 692.87 ft^2

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

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

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

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

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

$Vol_{catalyst} = Vol_{reactor}$ 2,771 ft^3 (Assumption)

SCR Reactor Dimensions

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

$A_{catalyst}$ = 144.3 ft^2

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

A_{SCR} = 166.0 ft^2

l_{scr} = 12.9 ft

w_{scr} = 12.9 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)

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

NOx_{in} = 0.37 lb/MMBtu

Q_B = 481 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

$\dot{m}_{reagent}$ = 55.3 lbs/hr

For ammonia,

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

C_{sol} =	19%		(Percent concentration of the aqueous reagent solution)
= $\dot{m}_{sol}$	291.2	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} =	38.9	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} =	13072	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	Clairton PA is 902 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 $) = $12,173,940 (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 =	$	60,870	

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 =	$ 191,909	$= q_{sol}$ 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 =	269.4	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} =	$ 210,948	(CCM SCR June 2019, Equation 2.61)
Additional Energy Requirement =	$ 5,829,839	(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)
$Vol_{catalyst}$ =	$	2,771	ft^3
Catalyst Replacement Cost (2022 $)=	$	957,567.57	(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 = $ 326,356

Total DAC (2022 $)= $ 6,722,121

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 = $12,173,940

IDAC (2022 $) = $ 1,239,943

Total Annual Cost (2022 $):
Total Annual Cost, TAC = DAC + IDAC = $ 7,962,064.07

COMPANY: United States Steel
LOCATION: Clairton
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	**481**
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	**269**
Freight & Ins. to Site, % of FOB	**Included in DC**			Reagent sol, gal/hr	**38.9**
Maintenance (Materials + Labor) % TCI	**0.5%**			Catalyst operating life, hrs	**24,000**
				Reagent Volume, gallons/hr	**38.9**
				Reagent Cost, $/gallon	**0.56**

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

TOTAL CAPITAL INVESTMENT			**COST EFFECTIVENESS**	
TOTAL CAPITAL INVESTMENT, TCI		**$ 12,173,940**		
TOTAL ANNUAL COST			Efficiency, %	80%
			Boiler Heat Input, MMBtu/hr	481
Direct Annual Costs			Total Operating Time, hrs/yr	8,760
Operating & Supervisory Labor	$102,200			
Maintenance	$60,870		NO_X removed, tpy	624.0
Reagent Consumption	$191,909			
Utilities	$210,948			
Catalyst Replacement	$326,356			
Auxilliary Equipment Requirements	$5,829,839			
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SCR required temperature.)			**Cost Efficiency:**	
			$/ton NO_X removed	**$ 12,760**
Total Direct Annual Costs	$6,722,121			
Indirect Annual Costs				
CRF	0.10185			
IDAC (CRF x TCI)	$1,239,943			
TOTAL ANNUAL COST, TAC	**$7,962,064**			

SCR Design Parameters used for Estimation

R1 Boiler Max. Heat Input, Q_B = 229 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	229.0	MMBtu/hr
Potential	229	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)= 0.31 lb/MMBtu (Potential, 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, $q_{fluegas}$

$q_{fluegas}$ = 27,390 acfm - based on testing at boilers (set equal to R2 values)

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
$Vol_{reactor}$ =	547.8	ft^3
$Area_{reactor}$ =	0.005	ft^2/cfm
$Area_{reactor}$ =	136.95	ft^2

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

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

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

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

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

$Vol_{catalyst} = Vol_{reactor}$ 548 ft^3 (Assumption)

SCR Reactor Dimensions

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

$A_{catalyst}$ = 28.5 ft^2

$A_{SCR} = 1.15 \text{ x } A_{catalyst}$

A_{SCR} =	32.8	ft^2
l_{scr} =	5.7	ft
w_{scr} =	5.7	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} =	0.31	lb/MMBtu
Q_B =	229	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
$\dot{m}_{reagent}$ =	22.1	lbs/hr

For ammonia,

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

C_{sol} =	19%		(Percent concentration of the aqueous reagent solution)
= $\dot{m}_{sol}$	116.2	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} =	15.5	gph	

Tank volume:

$Vol_{Tank} = q_{sol} \times t$

t =	14.0	days	(Common on site storage requirement, Section 2.3.13 of SCR manual)
Vol_{Tank} =	5214	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	Clairton PA is 902 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 $) =	$7,515,016	(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 =	$	37,575	

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 =	$	76,550	= 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 =		128.2	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} =	$	100,430	(CCM SCR June 2019, Equation 2.61)
Additional Energy Requirement =	$	759,442	(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)
$Vol_{catalyst}$ =	$	548	ft^3
Catalyst Replacement Cost (2022 $)=	$	189,269.10	(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 =	3.41E-01	

Annual Catalyst Replacement Cost = $ 64,506

Total DAC (2022 $)= $ 1,140,704

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 = $7,515,016

IDAC (2022 $) = $ 765,421

Total Annual Cost (2022 $):
Total Annual Cost, TAC = DAC + IDAC = $ 1,906,124.64

COMPANY: United States Steel
LOCATION: Clairton
Source: R1 Boiler
NOX Emission Control Option: SCR (80% Efficiency)

Site Information

Utility Unit Costs	
Electricity, $/kwh	**0.09**
Interest Rate, %	**8.00%**
Operating Labor, $/man-hr	**70.00**
Manhours per year	**1,460**
Sales Tax, % of FOB	**N/A**
Freight & Ins. to Site, % of FOB	**Included in DC**
Maintenance (Materials + Labor) % TCI	**0.5%**

Source Emission Information

Equipment Life, yr	**20.0**
Operating Hours Per Year	**8,760**

Control Technology Information

Boiler Fuel Rating, mmBTU/hr	**229**
NOX Removal Efficiency, η_{NOx}	**80%**
Cost Year	**2022**
Incremental Utility Requirement	
Electricity, kw	**128**
Reagent sol, gal/hr	**15.5**
Catalyst operating life, hrs	**24,000**
Reagent Volume, gallons/hr	**15.5**
Reagent Cost, $/gallon	**0.56**

COMPANY: United States Steel
LOCATION: Clairton
Source: R1 Boiler
NOX Emission Control Option: SCR (80% Efficiency)

TOTAL CAPITAL INVESTMENT			**COST EFFECTIVENESS**	
TOTAL CAPITAL INVESTMENT, TCI		**$ 7,515,016**		
TOTAL ANNUAL COST			Efficiency, %	80%
			Boiler Heat Input, MMBtu/hr	229
Direct Annual Costs			Total Operating Time, hrs/yr	8,760
Operating & Supervisory Labor	$102,200			
Maintenance	$37,575		NO_X removed, tpy	248.8
Reagent Consumption	$76,550			
Utilities	$100,430			
Catalyst Replacement	$64,506			
Auxilliary Equipment Requirements	$759,442			
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SCR required temperature.)			**Cost Efficiency:**	
			$/ton NO_X removed	**$ 7,663**
Total Direct Annual Costs	$1,140,704			
Indirect Annual Costs				
CRF	0.10185			
IDAC (CRF x TCI)	$765,421			
TOTAL ANNUAL COST, TAC	**$1,906,125**			

SCR Design Parameters used for Estimation

R2 Boiler Max. Heat Input, Q_B = 229 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	229.0	MMBtu/hr
Potential	229	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)= 0.31 lb/MMBtu (Potential, 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, $q_{fluegas}$

$q_{fluegas}$ = 27,390 acfm - based on testing at boilers.

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

$Vol_{reactor}$ = 547.8 ft^3

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

$Area_{reactor}$ = 136.95 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)

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

$Vol_{catalyst} = Vol_{reactor}$ 548 ft^3 (Assumption)

SCR Reactor Dimensions

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

$A_{catalyst}$ = 28.5 ft^2

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

A_{SCR} = 32.8 ft^2

l_{scr} = 5.7 ft

w_{scr} = 5.7 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} =	0.31	lb/MMBtu
Q_B =	229	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
$\dot{m}_{reagent}$ =	22.1	lbs/hr

For ammonia,

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

C_{sol} =	19%	(Percent concentration of the aqueous reagent solution)	
= $\dot{m}_{sol}$	116.2	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} =	15.5	gph	

Tank volume:

$Vol_{Tank} = q_{sol} \times t$

t =	14.0	days	(Common on site storage requirement, Section 2.3.13 of SCR manual)
Vol_{Tank} =	5214	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	Clairton PA is 902 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 $) = $7,515,016 (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 =	$ 37,575	

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 =	$ 76,550	$= q_{sol}$ 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 =	128.2	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} =	$ 100,430	(CCM SCR June 2019, Equation 2.61)
Additional Energy Requirement =	$ 759,442	(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)
$Vol_{catalyst}$ =	$ 548	ft^3
Catalyst Replacement Cost (2022 $)=	$ 189,269.10	(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 =	3.41E-01	
Annual Catalyst Replacement Cost =	$ 64,506	
Total DAC (2022 $)=	$ 1,140,704	

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 =	$7,515,016	
IDAC (2022 $) =	$ 765,421	

Total Annual Cost (2022 $):
Total Annual Cost, TAC = DAC + IDAC = $ 1,906,124.64

COMPANY: United States Steel
LOCATION: Clairton
Source: R2 Boiler
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	**229**
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	**128**
Freight & Ins. to Site, % of FOB	**Included in DC**			Reagent sol, gal/hr	**15.5**
Maintenance (Materials + Labor) % TCI	**0.5%**			Catalyst operating life, hrs	**24,000**
				Reagent Volume, gallons/hr	**15.5**
				Reagent Cost, $/gallon	**0.56**

COMPANY: United States Steel
LOCATION: Clairton
Source: R2 Boiler
NOX Emission Control Option: SCR (80% Efficiency)

TOTAL CAPITAL INVESTMENT			**COST EFFECTIVENESS**	
TOTAL CAPITAL INVESTMENT, TCI		**$ 7,515,016**		
TOTAL ANNUAL COST			Efficiency, %	80%
			Boiler Heat Input, MMBtu/hr	229
Direct Annual Costs			Total Operating Time, hrs/yr	8,760
Operating & Supervisory Labor	$102,200			
Maintenance	$37,575		NO_X removed, tpy	248.8
Reagent Consumption	$76,550			
Utilities	$100,430			
Catalyst Replacement	$64,506			
Auxilliary Equipment Requirements	$759,442			
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SCR required temperature.)			**Cost Efficiency:**	
			\$/ton NO_X removed	**$ 7,663**
Total Direct Annual Costs	$1,140,704			
Indirect Annual Costs				
CRF	0.10185			
IDAC (CRF x TCI)	$765,421			
TOTAL ANNUAL COST, TAC	**$1,906,125**			

SCR Design Parameters used for Estimation

T1 Boiler Max. Heat Input, Q_B = 156 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	156.0	MMBtu/hr
Potential	156	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)= 0.31 lb/MMBtu (Potential, 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, $q_{fluegas}$

$q_{fluegas}$ = 36,360 acfm - based on testing at boilers.

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
$Vol_{reactor}$ =	727.2	ft^3
$Area_{reactor}$ =	0.005	ft^2/cfm
$Area_{reactor}$ =	181.8	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)

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

$Vol_{catalyst} = Vol_{reactor}$ 727 ft^3 (Assumption)

SCR Reactor Dimensions

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

$A_{catalyst}$ = 37.9 ft^2

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

A_{SCR} =	43.6	ft^2
l_{scr} =	6.6	ft
w_{scr} =	6.6	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} =	0.31	lb/MMBtu
Q_B =	156	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
$\dot{m}_{reagent}$ =	15.0	lbs/hr

For ammonia,

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

C_{sol} =	19%		(Percent concentration of the aqueous reagent solution)
= $\dot{m}_{sol}$	79.1	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} =	10.6	gph	

Tank volume:

$Vol_{Tank} = q_{sol} \times t$

t =	14.0	days	(Common on site storage requirement, Section 2.3.13 of SCR manual)
Vol_{Tank} =	3552	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	Clairton PA is 902 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 $) = $5,855,552 (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 =	$	29,278		

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 =	$	52,148	= 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 =		87.4	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} =	$	68,415	(CCM SCR June 2019, Equation 2.61)
Additional Energy Requirement =	$	1,306,873	(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)
$Vol_{catalyst}$ =	$	727	ft^3
Catalyst Replacement Cost (2022 $)=	$	251,253.17	(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 =	3.41E-01	

Annual Catalyst Replacement Cost = $ 85,631

Total DAC (2022 $)= $ 1,644,546

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 = $5,855,552

IDAC (2022 $) = $ 596,401

Total Annual Cost (2022 $):
Total Annual Cost, TAC = DAC + IDAC = $ 2,240,946.60

COMPANY: United States Steel
LOCATION: Clairton
Source: T1 Boiler
NOX Emission Control Option: SCR (80% Efficiency)

Site Information

Utility Unit Costs	
Electricity, $/kwh	**0.09**
Interest Rate, %	**8.00%**
Operating Labor, $/man-hr	**70.00**
Manhours per year	**1,460**
Sales Tax, % of FOB	**N/A**
Freight & Ins. to Site, % of FOB	**Included in DC**
Maintenance (Materials + Labor) % TCI	**0.5%**

Source Emission Information

Equipment Life, yr	**20.0**
Operating Hours Per Year	**8,760**

Control Technology Information

Boiler Fuel Rating, mmBTU/hr	**156**
NOX Removal Efficiency, η_{NOx}	**80%**
Cost Year	**2022**
Incremental Utility Requirement	
Electricity, kw	**87**
Reagent sol, gal/hr	**10.6**
Catalyst operating life, hrs	**24,000**
Reagent Volume, gallons/hr	**10.6**
Reagent Cost, $/gallon	**0.56**

COMPANY: United States Steel
LOCATION: Clairton
Source: T1 Boiler
NOX Emission Control Option: SCR (80% Efficiency)

TOTAL CAPITAL INVESTMENT			**COST EFFECTIVENESS**		
TOTAL CAPITAL INVESTMENT, TCI		**$ 5,855,552**			
TOTAL ANNUAL COST			Efficiency, %	80%	
			Boiler Heat Input, MMBtu/hr	156	
Direct Annual Costs			Total Operating Time, hrs/yr	8,760	
Operating & Supervisory Labor	$102,200				
Maintenance	$29,278		NO_X removed, tpy	169.5	
Reagent Consumption	$52,148				
Utilities	$68,415				
Catalyst Replacement	$85,631				
Auxilliary Equipment Requirements	$1,306,873				
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SCR required temperature.)			**Cost Efficiency:**		
			\$/ton NO_X removed	**$**	**13,224**
Total Direct Annual Costs	$1,644,546				
Indirect Annual Costs					
CRF	0.10185				
IDAC (CRF x TCI)	$596,401				
TOTAL ANNUAL COST, TAC	**$2,240,947**				

SCR Design Parameters used for Estimation

T2 Boiler Max. Heat Input, Q_B = 156 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	156.0	MMBtu/hr
Potential	156	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)= 0.31 lb/MMBtu (Potential, 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, $q_{fluegas}$

$q_{fluegas}$ = 37,307 acfm - based on testing at boilers.

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

$Vol_{reactor}$ = 746.14 ft^3

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

$Area_{reactor}$ = 186.535 ft^2

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

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

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

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

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

$Vol_{catalyst} = Vol_{reactor}$ 746 ft^3 (Assumption)

SCR Reactor Dimensions

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

$A_{catalyst}$ = 38.9 ft^2

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

A_{SCR} = 44.7 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} =	0.31	lb/MMBtu
Q_B =	156	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
$\dot{m}_{reagent}$ =	15.0	lbs/hr

For ammonia,

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

C_{sol} =	19%		(Percent concentration of the aqueous reagent solution)
= $\dot{m}_{sol}$	79.1	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} =	10.6	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} =	3552	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	Clairton PA is 902 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 $) = $5,855,552 (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 =	$	29,278	

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 =	$ 52,148	= 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 =		87.4	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} =	$	68,415	(CCM SCR June 2019, Equation 2.61)
Additional Energy Requirement =	$	1,021,921	(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)
$Vol_{catalyst}$ =	$	746	ft^3
Catalyst Replacement Cost (2022 $)=	$	257,797.09	(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 =	3.41E-01	

Annual Catalyst Replacement Cost = $ 87,862

Total DAC (2022 $)= $ 1,361,824

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 = $5,855,552

IDAC (2022 $) = $ 596,401

Total Annual Cost (2022 $):
Total Annual Cost, TAC = DAC + IDAC = $ 1,958,224.85

COMPANY: United States Steel
LOCATION: Clairton
Source: T2 Boiler
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	**156**
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	**87**
Freight & Ins. to Site, % of FOB	**Included in DC**			Reagent sol, gal/hr	**10.6**
Maintenance (Materials + Labor) % TCI	**0.5%**			Catalyst operating life, hrs	**24,000**
				Reagent Volume, gallons/hr	**10.6**
				Reagent Cost, $/gallon	**0.56**

COMPANY: United States Steel
LOCATION: Clairton
Source: T2 Boiler
NOX Emission Control Option: SCR (80% Efficiency)

TOTAL CAPITAL INVESTMENT			**COST EFFECTIVENESS**		
TOTAL CAPITAL INVESTMENT, TCI		**$ 5,855,552**			
TOTAL ANNUAL COST			Efficiency, %		80%
			Boiler Heat Input, MMBtu/hr		156
Direct Annual Costs			Total Operating Time, hrs/yr		8,760
Operating & Supervisory Labor	$102,200				
Maintenance	$29,278		NO_X removed, tpy		169.5
Reagent Consumption	$52,148				
Utilities	$68,415				
Catalyst Replacement	$87,862				
Auxilliary Equipment Requirements	$1,021,921				
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SCR required temperature.)			**Cost Efficiency:**		
			$/ton NO_X removed	**$**	**11,556**
Total Direct Annual Costs	$1,361,824				
Indirect Annual Costs					
CRF	0.10185				
IDAC (CRF x TCI)	$596,401				
TOTAL ANNUAL COST, TAC	**$1,958,225**				

SNCR Costs for Boilers

Source	Annualized Costs ($/yr)	NOx PTE (tpy)	Controlled Emissions (tpy)	Emissions Reduction (tpy)	Cost Effectiveness ($/ton)
Boiler 1	32,806,833	1,598.00	878.90	719.10	45,622
Boiler 2	19,129,906	780.00	429.00	351.00	54,501
R1 Boiler	3,506,417	310.94	171.02	139.92	25,060
R2 Boiler	3,506,417	310.94	171.02	139.92	25,060
T1 Boiler	4,816,160	211.82	116.50	95.32	50,527
T2 Boiler	4,385,975	211.82	116.50	95.32	46,014

Heat Capacity Boiler Combustion Stack Gas - SNCR Reheat

	BOILER #2		BOILER #R1		BOILER #R2		BOILER #T1		BOILER #T2		BOILER #1	
	Flue Gas Composition	Heat Capacity (Btu/ft^3/°F)	Flue Gas Composition	Heat Capacity (Btu/ft^3/°F)	Flue Gas Composition	Heat Capacity (Btu/ft^3/°F)	Flue Gas Composition	Heat Capacity (Btu/ft^3/°F)	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	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225	7.3%	0.0225
O2	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185	13.2%	0.0185
CO2	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260	4.0%	0.0260
N2	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185	75.5%	0.0185
Total	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**	**100.0%**	**0.0191**

	BOILER #2	BOILER #R1	BOILER #R2	BOILER #T1	BOILER #T2	BOILER #1
Flow (1)	95,225 scfm	16,405 scfm	16,405 scfm	23,544 scfm	22,403 scfm	165,377 scfm
Flow	**5.71E+06 scfh**	**9.84E+05 scfh**	**9.84E+05 scfh**	**1.41E+06 scfh**	**1.34E+06 scfh**	**9.92E+06 scfh**
Temperature$_{SNCR\ in}$ (1)	**287.5 F**	**395.4 F**	**395.4 F**	**328.8 F**	**400.3 F**	**297.6 F**
Temperature$_{SNCR\ out}$ (2)	**1650 F**	**1650 F**	**1650 F**	**1650 F**	**1650 F**	**1650 F**
ΔT	**1362.5** F	**1254.6** F	**1254.6** F	**1321.2** F	**1249.7** F	**1352.4** F
Heat Requirement	26.0 Btu/scf	24.0 Btu/scf	24.0 Btu/scf	25.2 Btu/scf	23.9 Btu/scf	25.8 Btu/scf
Uncontrolled NOX (3)	178.0 lb / hr	71.0 lb / hr	71.0 lb / hr	48.4 lb / hr	48.4 lb / hr	364.8 lb / hr
NOX control eff'y (2)	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%
NOX Removed	80.1 lb / hr	31.9 lb / hr	31.9 lb / hr	21.8 lb / hr	21.8 lb / hr	164.2 lb / hr
NOX Removed	1.40E-05 lb/scf flue gas	3.25E-05 lb/scf flue gas	3.25E-05 lb/scf flue gas	1.54E-05 lb/scf flue gas	1.62E-05 lb/scf flue gas	1.65E-05 lb/scf flue gas
NOX from Natural Gas Combustion (4)	4.55E-06 lb/scf flue gas	4.19E-06 lb/scf flue gas	4.19E-06 lb/scf flue gas	4.41E-06 lb/scf flue gas	4.18E-06 lb/scf flue gas	4.52E-06 lb/scf flue gas
Net NOX Reduction	9.46E-06 lb/scf flue gas	2.83E-05 lb/scf flue gas	2.83E-05 lb/scf flue gas	1.10E-05 lb/scf flue gas	1.20E-05 lb/scf flue gas	1.20E-05 lb/scf flue gas
Natural Gas Eff'y	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
Natural Gas Req'd	32.5 Btu/scf flue gas	29.9 Btu/scf flue gas	29.9 Btu/scf flue gas	31.5 Btu/scf flue gas	29.8 Btu/scf flue gas	32.3 Btu/scf flue gas
Natural Gas Req'd	3.25E-05 MMBtu/scf flue gas	2.99E-05 MMBtu/scf flue gas	2.99E-05 MMBtu/scf flue gas	3.15E-05 MMBtu/scf flue gas	2.98E-05 MMBtu/scf flue gas	3.23E-05 MMBtu/scf flue gas
Natural Gas Cost (5)	$11.03 / MMbtu	$11.03 / MMbtu	$11.03 / MMbtu	$11.03 / MMbtu	$11.03 / MMbtu	$11.03 / MMbtu
Natural Gas Cost	$37.89 /lb NOX Removed	$11.68 /lb NOX Removed	$11.68 /lb NOX Removed	$31.64 /lb NOX Removed	$27.38 /lb NOX Removed	$29.60 /lb NOX Removed
Annual Natural Gas Cost (6)	$17,950,634	$2,847,566	$2,847,566	$4,303,691	$3,873,506	$30,943,724

(1) Average of the latest stack test data for flow and temperature. R1 set equal to R2 stack test parameters (flowrate and temperature)
(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 = 760 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	760	MMBtu/hr
Potential	760	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)= 0.48 lb/MMBtu (Potential, 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 = 1.56

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)

$\dot{m}_{reagent}$ = 166.7 lbs/hr

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

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

$\dot{m}_{sol}$ = 333.5 lbs/hr

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

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

q_{sol} = 35.14 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} = 11,805.69 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 \$) = \$ 3,074,856.99 (Chemical Engineering Plant Index difference applied to DC)

Indirect Capital Costs:

Total Indirect Installation Costs, IC (2022 \$) = \$ 614,971

=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 =	\$ 553,474.26	
=	15%	of DC + IC
Total Plant Cost, D =	\$ 4,243,302.65	= DC + IC + C

Allowance for Funds During Construction, E =	$ -	(Assumed zero for SNCR)	
Royalty Allowance,F =	$ -	(Assumed zero for SNCR)	
Preproduction Costs, G =	$ 84,866.05		
=	2%	of D + E	
Inventory Capital, H =	$ 1,039,892.69	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)	
$Vol_{reagent}$ =	306,948	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 =	$ 5,368,061.39	= 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.

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

Operating and Supervisory Labor:
In general, no additional personnel is required to operate or maintain the SNCR equipment for large industrial facilities. A small amount is accounted for on summary tab.

Maintenance:

1.5% of TCI
Maintenance = $ 80,521

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 =	\$	1,042,750	= 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)=		0.48	lb/MMBtu
NSR (Normalized Stoichiometric Ratio):		1.56	
Q_B, boiler heat input=		760	MMBtu/hr
P =		28	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} =	\$	21,996	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} =		0.160	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)
	\$	21,079.56	

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

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

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) = 1.3506$$

Annual cost for additional fuel:

Additional fuel required:

Natural gas	1.35063	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)
	$ 111,689.13	$/yr	
Total Natural gas:	$ 111,689.13		
Additional Energy Requirement =	$ 30,943,724	(Additional heating of exhaust gas required for SNCR operations.)	
Total DAC =	$ 32,221,759.50		

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 $) = $ 5,368,061.39

IDAC = $ 546,748.91

Total Annual Cost (2022 $):
Total Annual Cost, TAC = DAC + IDAC = $ 32,768,508.41

COMPANY: United State Steel
LOCATION: Clairton
Source: Boiler #1
NO_X Emission Control Option: SNCR (45% 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	760
Interest Rate, %	8.00%	Operating Hours Per Year	8760	NOX Removal Efficiency, η_{NOx}	45%
Water, $/1,000 gal	15.05			Cost Year	2022
				Incremental Utility Requirements	
NG, $/MMBtu	9.44			Electricity, kw	28
				Reagent sol, gal/hr	35.14
Operating Labor, $/man-hr	70.00			Water, 1,000 gal/hr	0.16
Manhours per year	547.5				
Sales Tax, % of FOB	Included in DC				
Freight & Ins. to Site, % of FOB	Included in DC			NG, MMBtu/hr	1.35063
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%				
				Reagent Volume, gallons	306,948
				Reagent Cost, $/gallon	3.39

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

TOTAL CAPITAL INVESTMENT		
Total Direct Capital Cost, DC	$	3,074,857
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	$	614,971
Project Contingency, C	$	553,474
Total Plant Cost, D (DC + IC + C)	$	4,243,303
Allowance for Funds During Constr., E	$	-
Royalty Allowance,F	$	-
Preproduction Costs, G	$	84,866
Inventory Capital, H	$	1,039,893
Initial Catalyst and Chemicals, I	$	-
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)	**$**	**5,368,061**

TOTAL ANNUAL COST		
Direct Annual Costs		
Operating & Supervisory Labor	$38,325	
Maintenance	$80,521	
Reagent Consumption	$1,042,750	
Utilities	$21,996	
Water Consumption	$21,080	
Add'l Fuel Usage (Process related)	$111,689.13	
Auxiliary Equipment Requirements	$ 30,943,724	
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)		
Total Direct Annual Costs		$32,260,085
Indirect Annual Costs		
CRF	0.102	
Total IDAC (CRF x TCI)		$ 546,749
TOTAL ANNUAL COST, TAC (DAC + IDAC)		**$ 32,806,833**

COST EFFECTIVENESS	
NOX_{in}, lbs/MMBtu	0.48
Efficiency, %	45%
Boiler Heat Input, MMBtu/hr	760
Total Operating Time, hrs/yr	8760
NO_X removed, tpy	719.1
Cost Efficiency:	
\$/ton NO_X removed	**$45,622**

SNCR Design Parameters used for Estimation

Boiler #2 Max. Heat Input, Q_B = 481 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	481	MMBtu/hr
Potential	481	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)= 0.37 lb/MMBtu (Potential, 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 = 1.75

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)

$\dot{m}_{reagent}$ = 91.5 lbs/hr

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

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

$\dot{m}_{sol}$ = 183.1 lbs/hr

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

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

q_{sol} = 19.29 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} = 6,481.53 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 $) = $ 2,533,892.23 (Chemical Engineering Plant Index difference applied to DC)

Indirect Capital Costs:

Total Indirect Installation Costs, IC (2022 $) = $ 506,778

=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 =	$ 456,100.60	
=	15%	of DC + IC
Total Plant Cost, D =	$ 3,496,771.27	= DC + IC + C

Allowance for Funds During Construction, E =	$ -	(Assumed zero for SNCR)	
Royalty Allowance,F =	$ -	(Assumed zero for SNCR)	
Preproduction Costs, G =	$ 69,935.43		
=	2%	of D + E	
Inventory Capital, H =	$ 570,918.89	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)	
$Vol_{reagent}$ =	168,520	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 =	$ 4,137,625.59	= 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. A small amount is accounted for on summary tab.

<u>Maintenance:</u>

1.5% of TCI
Maintenance = $ 62,064

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 =	\$	572,487	$= q_{sol} \times cost_{reagent} \times t_{op}$

Utilities:

Power Consumption, P:

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

NOx_{in}, (uncontrolled)=		0.37	lb/MMBtu
NSR (Normalized Stoichiometric Ratio):		1.75	
Q_B, boiler heat input=		481	MMBtu/hr
P =		15	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} =	\$	12,076	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} =	0.088	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)
	\$	11,573.04	

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

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

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) = 0.7415$$

Annual cost for additional fuel:

Additional fuel required:

Natural gas	0.74152	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)
	$ 61,319.25	$/yr	
Total Natural gas:	$ 61,319.25		
Additional Energy Requirement =	$ 17,950,634	(Additional heating of exhaust gas required for SNCR operations.)	
Total DAC =	$ 18,670,154.70		

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 $) = $ 4,137,625.59

IDAC = $ 421,426.31

Total Annual Cost (2022 $):
Total Annual Cost, TAC = DAC + IDAC = $ 19,091,581.01

COMPANY: United State Steel
LOCATION: Clairton
Source: Boiler #2
NO_X Emission Control Option: SNCR (45% 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	481
Interest Rate, %	8.00%	Operating Hours Per Year	8760	NOX Removal Efficiency, η_{NOx}	45%
Water, $/1,000 gal	15.05			Cost Year	2022
				Incremental Utility Requirements	
NG, $/MMBtu	9.44			Electricity, kw	15
				Reagent sol, gal/hr	19.29
Operating Labor, $/man-hr	70.00			Water, 1,000 gal/hr	0.09
Manhours per year	547.5				
Sales Tax, % of FOB	Included in DC				
Freight & Ins. to Site, % of FOB	Included in DC			NG, MMBtu/hr	0.74152
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%				
				Reagent Volume, gallons	168,520
				Reagent Cost, $/gallon	3.39

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

TOTAL CAPITAL INVESTMENT		
Total Direct Capital Cost, DC	$	2,533,892
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	$	506,778
Project Contingency, C	$	456,101
Total Plant Cost, D (DC + IC + C)	$	3,496,771
Allowance for Funds During Constr., E	$	-
Royalty Allowance,F	$	-
Preproduction Costs, G	$	69,935
Inventory Capital, H	$	570,919
Initial Catalyst and Chemicals, I	$	-
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)	**$**	**4,137,626**

TOTAL ANNUAL COST		
Direct Annual Costs		
Operating & Supervisory Labor	$38,325	
Maintenance	$62,064	
Reagent Consumption	$572,487	
Utilities	$12,076	
Water Consumption	$11,573	
Add'l Fuel Usage (Process related)	$61,319.25	
Auxiliary Equipment Requirements	$17,950,634	
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)		
Total Direct Annual Costs		$18,708,480
Indirect Annual Costs		
CRF	0.102	
Total IDAC (CRF x TCI)		$ 421,426
TOTAL ANNUAL COST, TAC (DAC + IDAC)		**$ 19,129,906**

COST EFFECTIVENESS	
NOX_{in}, lbs/MMBtu	0.37
Efficiency, %	45%
Boiler Heat Input, MMBtu/hr	481
Total Operating Time, hrs/yr	8760
NO_X removed, tpy	351.0
Cost Efficiency:	
$/ton NO_X removed	**$54,501**

SNCR Design Parameters used for Estimation

R1 Boiler Max. Heat Input, Q_B = 229 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.

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

$$CF_{Boiler\#2} = \frac{Actual_{2016}, MMBtu/hr}{Potential, MMBtu/hr}$$

Worst-Case Actual	229.0	MMBtu/hr
Potential	229	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)= 0.31 lb/MMBtu (Potential, permit limit)

NOX Removal Efficiency, η_{NOx} = 45%

Stack NO_X = 0.1705 lb/MMBtu (Estimated)

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 = 1.92

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)

$\dot{m}_{reagent}$ = 40.0 lbs/hr

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

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

$\dot{m}_{sol}$ = 79.9 lbs/hr

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

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

q_{sol} = 8.42 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} = 2,828.65 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 \$) = \$ 1,851,190.79 (Chemical Engineering Plant Index difference applied to DC)

Indirect Capital Costs:

Total Indirect Installation Costs, IC (2022 \$) = \$ 370,238

=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 = \$ 333,214.34

= 15% of DC + IC

Total Plant Cost, D = \$ 2,554,643.29 = DC + IC + C

Allowance for Funds During Construction, E =	$	-	(Assumed zero for SNCR)	
Royalty Allowance,F =	$	-	(Assumed zero for SNCR)	
Preproduction Costs, G =	$	51,092.87		
=		2%	of D + E	
Inventory Capital, H =	$	249,158.82	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)	
$Vol_{reagent}$ =		73,545	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 =	$	2,854,894.97	= 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. A small amount is accounted for on summary tab.

<u>Maintenance:</u>

1.5% of TCI
Maintenance = $ 42,823

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 =	\$	249,843	$= q_{sol} \times cost_{reagent} \times t_{op}$

Utilities:

Power Consumption, P:

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

NOx_{in}, (uncontrolled)=		0.31	lb/MMBtu
NSR (Normalized Stoichiometric Ratio):		1.92	
Q_B, boiler heat input=		229	MMBtu/hr
P =		7	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} =	\$	5,270	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} =		0.038	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)
	\$	5,050.67	

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

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

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) = \quad 0.3236$$

Annual cost for additional fuel:

Additional fuel required:

Natural gas	0.32361	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)
	$ 26,760.77	$/yr	
Total Natural gas:	$ 26,760.77		
Additional Energy Requirement =	$ 2,847,566	(Additional heating of exhaust gas required for SNCR operations.)	
Total DAC =	$ 3,177,314.69		

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 $) = $ 2,854,894.97

IDAC = $ 290,777.36

Total Annual Cost (2022 $):
Total Annual Cost, TAC = DAC + IDAC = $ 3,468,092.05

COMPANY: United State Steel
LOCATION: Clairton
Source: R1 Boiler
NO_X Emission Control Option: SNCR (45% 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	**229**
Interest Rate, %	**8.00%**	Operating Hours Per Year	**8760**	NOX Removal Efficiency, η_{NOx}	**45%**
Water, $/1,000 gal	**15.05**			Cost Year	**2022**
				Incremental Utility Requirements	
NG, $/MMBtu	**9.44**			Electricity, kw	**7**
				Reagent sol, gal/hr	**8.42**
Operating Labor, $/man-hr	**70.00**			Water, 1,000 gal/hr	**0.04**
Manhours per year	**547.5**				
Sales Tax, % of FOB	**Included in DC**				
Freight & Ins. to Site, % of FOB	**Included in DC**			NG, MMBtu/hr	**0.32361**
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%**				
				Reagent Volume, gallons	**73,545**
				Reagent Cost, $/gallon	**3.39**

E

COMPANY: United State Steel
LOCATION: Clairton
Source: R1 Boiler
NO_X Emission Control Option: SNCR (45% Efficiency)

TOTAL CAPITAL INVESTMENT		
Total Direct Capital Cost, DC	$	1,851,191
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	$	370,238
Project Contingency, C	$	333,214
Total Plant Cost, D (DC + IC + C)	$	2,554,643
Allowance for Funds During Constr., E	$	-
Royalty Allowance,F	$	-
Preproduction Costs, G	$	51,093
Inventory Capital, H	$	249,159
Initial Catalyst and Chemicals, I	$	-
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)	**$**	**2,854,895**

TOTAL ANNUAL COST		
Direct Annual Costs		
Operating & Supervisory Labor	$38,325	
Maintenance	$42,823	
Reagent Consumption	$249,843	
Utilities	$5,270	
Water Consumption	$5,051	
Add'l Fuel Usage (Process related)	$26,760.77	
Auxiliary Equipment Requirements	$ 2,847,566	
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)		
Total Direct Annual Costs		$3,215,640
Indirect Annual Costs		
CRF	0.102	
Total IDAC (CRF x TCI)		$ 290,777
TOTAL ANNUAL COST, TAC (DAC + IDAC)		**$ 3,506,417**

COST EFFECTIVENESS	
NOX_{in}, lbs/MMBtu	0.31
Efficiency, %	45%
Boiler Heat Input, MMBtu/hr	229
Total Operating Time, hrs/yr	8760
NO_X removed, tpy	139.9
Cost Efficiency:	
\$/ton NO_X removed	**$25,060**

SNCR Design Parameters used for Estimation

R2 Boiler Max. Heat Input, Q_B = 229 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	229.0	MMBtu/hr
Potential	229	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)= 0.31 lb/MMBtu (Potential, permit limit)

NOX Removal Efficiency, η_{NOx} = 45%

Stack NO_X = 0.1705 lb/MMBtu (Estimated)

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 = 1.92

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)

$\dot{m}_{reagent}$ = 40.0 lbs/hr

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

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

$\dot{m}_{sol}$ = 79.9 lbs/hr

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

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

q_{sol} = 8.42 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} = 2,828.65 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:

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

DC (2022 $) = $ 1,851,190.79 (Chemical Engineering Plant Index difference applied to DC)

Indirect Capital Costs:

Total Indirect Installation Costs, IC (2022 $) = $ 370,238

=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 =	$ 333,214.34	
=	15%	of DC + IC
Total Plant Cost, D =	$ 2,554,643.29	= DC + IC + C

Allowance for Funds During Construction, E =	$ -	(Assumed zero for SNCR)	
Royalty Allowance,F =	$ -	(Assumed zero for SNCR)	
Preproduction Costs, G =	$ 51,092.87		
=	2%	of D + E	
Inventory Capital, H =	$ 249,158.82	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)	
$Vol_{reagent}$ =	73,545	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 =	$ 2,854,894.97	= 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. A small amount is accounted for on summary tab.

<u>Maintenance:</u>

1.5% of TCI
Maintenance = $ 42,823

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 =	\$	249,843	$= q_{sol} \times cost_{reagent} \times t_{op}$

Utilities:

Power Consumption, P:

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

NOx_{in}, (uncontrolled)=		0.31	lb/MMBtu
NSR (Normalized Stoichiometric Ratio):		1.92	
Q_B, boiler heat input=		229	MMBtu/hr
P =		7	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} =	\$	5,270	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} =	0.038	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)
	\$	5,050.67	

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

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

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) = 0.3236$$

Annual cost for additional fuel:

Additional fuel required:

Natural gas	0.32361	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)
	$ 26,760.77	$/yr	
Total Natural gas:	$ 26,760.77		
Additional Energy Requirement =	$ 2,847,566	(Additional heating of exhaust gas required for SNCR operations.)	
Total DAC =	$ 3,177,314.69		

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 $) = $ 2,854,894.97

IDAC = $ 290,777.36

Total Annual Cost (2022 $):
Total Annual Cost, TAC = DAC + IDAC = $ 3,468,092.05

COMPANY: **United State Steel**
LOCATION: **Clairton**
Source: **R2 Boiler**
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	229
NOX Removal Efficiency, η_{NOx}	45%
Cost Year	2022
Incremental Utility Requirements	
Electricity, kw	7
Reagent sol, gal/hr	8.42
Water, 1,000 gal/hr	0.04
NG, MMBtu/hr	0.32361
Reagent Volume, gallons	73,545
Reagent Cost, $/gallon	3.39

E

COMPANY: United State Steel
LOCATION: Clairton
Source: R2 Boiler
NO_X Emission Control Option: SNCR (45% Efficiency)

TOTAL CAPITAL INVESTMENT		
Total Direct Capital Cost, DC	$	1,851,191
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	$	370,238
Project Contingency, C	$	333,214
Total Plant Cost, D (DC + IC + C)	$	2,554,643
Allowance for Funds During Constr., E	$	-
Royalty Allowance,F	$	-
Preproduction Costs, G	$	51,093
Inventory Capital, H	$	249,159
Initial Catalyst and Chemicals, I	$	-
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)	**$**	**2,854,895**

TOTAL ANNUAL COST			
Direct Annual Costs			
Operating & Supervisory Labor	$38,325		
Maintenance	$42,823		
Reagent Consumption	$249,843		
Utilities	$5,270		
Water Consumption	$5,051		
Add'l Fuel Usage (Process related)	$26,760.77		
Auxiliary Equipment Requirements	$ 2,847,566		
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)			
Total Direct Annual Costs			$3,215,640
Indirect Annual Costs			
CRF	0.102		
Total IDAC (CRF x TCI)		$	290,777
TOTAL ANNUAL COST, TAC (DAC + IDAC)		**$**	**3,506,417**

COST EFFECTIVENESS	
NOX_{in}, lbs/MMBtu	0.31
Efficiency, %	45%
Boiler Heat Input, MMBtu/hr	229
Total Operating Time, hrs/yr	8760
NO_X removed, tpy	139.9
Cost Efficiency:	
\$/ton NO_X removed	**$25,060**

SNCR Design Parameters used for Estimation

T1 Boiler Max. Heat Input, Q_B = 156 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	156.0	MMBtu/hr
Potential	156	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)=	0.31	lb/MMBtu (Potential, permit limit)
NOX Removal Efficiency, η_{NOx} =	45%	
Stack NO_X =	0.1705	lb/MMBtu (Estimated)

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 = 1.92

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)

$\dot{m}_{reagent}$ = 27.2 lbs/hr

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

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

$\dot{m}_{sol}$ = 54.4 lbs/hr

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

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

q_{sol} = 5.73 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} = 1,926.94 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 $) = $ 1,573,738.17 (Chemical Engineering Plant Index difference applied to DC)

Indirect Capital Costs:

Total Indirect Installation Costs, IC (2022 $) = $ 314,748

=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 =	$ 283,272.87	
=	15%	of DC + IC
Total Plant Cost, D =	$ 2,171,758.67	= DC + IC + C

Allowance for Funds During Construction, E =	$	-	(Assumed zero for SNCR)	
Royalty Allowance,F =	$	-	(Assumed zero for SNCR)	
Preproduction Costs, G =	$	43,435.17		
=		2%	of D + E	
Inventory Capital, H =	$	169,732.64	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)	
$Vol_{reagent}$ =		50,100	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 =	$	2,384,926.48	= 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. A small amount is accounted for on summary tab.

<u>Maintenance:</u>

1.5%	of TCI			
Maintenance =	$	35,774		
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 =	\$	170,199	$= q_{sol} \times cost_{reagent} \times t_{op}$

Utilities:

Power Consumption, P:

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

NOx_{in}, (uncontrolled)=		0.31	lb/MMBtu
NSR (Normalized Stoichiometric Ratio):		1.92	
Q_B, boiler heat input=		156	MMBtu/hr
P =		5	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} =	\$	3,590	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} =	0.026	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)
	\$	3,440.63	

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

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

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) \quad = \quad 0.2205$$

Annual cost for additional fuel:

Additional fuel required:

Natural gas	0.22045	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)
	$ 18,230.05	$/yr	
Total Natural gas:	$ 18,230.05		
Additional Energy Requirement =	$ 4,303,691	(Additional heating of exhaust gas required for SNCR operations.)	
Total DAC =	$ 4,534,925.18		

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 $) = $ 2,384,926.48

IDAC = $ 242,910.03

Total Annual Cost (2022 $):
Total Annual Cost, TAC = DAC + IDAC = $ 4,777,835.21

COMPANY: **United State Steel**
LOCATION: **Clairton**
Source: **T1 Boiler**
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	**156**
NOX Removal Efficiency, η_{NOx}	**45%**
Cost Year	**2022**
Incremental Utility Requirements	
Electricity, kw	**5**
Reagent sol, gal/hr	**5.73**
Water, 1,000 gal/hr	**0.03**
NG, MMBtu/hr	**0.22045**
Reagent Volume, gallons	**50,100**
Reagent Cost, $/gallon	**3.39**

E

COMPANY: United State Steel
LOCATION: Clairton
Source: T1 Boiler
NO_X Emission Control Option: SNCR (45% Efficiency)

TOTAL CAPITAL INVESTMENT

Total Direct Capital Cost, DC	$	1,573,738
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	$	314,748
Project Contingency, C	$	283,273
Total Plant Cost, D (DC + IC + C)	$	2,171,759
Allowance for Funds During Constr., E	$	-
Royalty Allowance,F	$	-
Preproduction Costs, G	$	43,435
Inventory Capital, H	$	169,733
Initial Catalyst and Chemicals, I	$	-
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)	**$**	**2,384,926**

TOTAL ANNUAL COST

Direct Annual Costs		
Operating & Supervisory Labor	$38,325	
Maintenance	$35,774	
Reagent Consumption	$170,199	
Utilities	$3,590	
Water Consumption	$3,441	
Add'l Fuel Usage (Process related)	$18,230.05	
Auxiliary Equipment Requirements	$ 4,303,691	
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)		
Total Direct Annual Costs		$4,573,250
Indirect Annual Costs		
CRF	0.102	
Total IDAC (CRF x TCI)		$ 242,910
TOTAL ANNUAL COST, TAC (DAC + IDAC)		**$ 4,816,160**

COST EFFECTIVENESS

NOX_{in}, lbs/MMBtu	0.31
Efficiency, %	45%
Boiler Heat Input, MMBtu/hr	156
Total Operating Time, hrs/yr	8760
NO_X removed, tpy	95.3
Cost Efficiency:	
\$/ton NO_X removed	**$50,527**

<u>SNCR Design Parameters used for Estimation</u>

T2 Boiler Max. Heat Input, Q_B = 156 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	156.0	MMBtu/hr
Potential	156	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)=	0.31	lb/MMBtu (Potential, permit limit)
NOX Removal Efficiency, η_{NOx} =	45%	
Stack NO_X =	0.1705	lb/MMBtu (Estimated)

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 = 1.92

Estimating Reagent Consumption

Reagent Consumption Parameters:

$\rho_{sol} =$	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)

$\dot{m}_{reagent}$ = 27.2 lbs/hr

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

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

$\dot{m}_{sol}$ = 54.4 lbs/hr

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

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

$q_{sol} =$ 5.73 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)

$V_{tank} =$ 1,926.94 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 $) = $ 1,573,738.17 (Chemical Engineering Plant Index difference applied to DC)

Indirect Capital Costs:

Total Indirect Installation Costs, IC (2022 $) = $ 314,748

=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 =	$ 283,272.87	
=	15%	of DC + IC
Total Plant Cost, D =	$ 2,171,758.67	= DC + IC + C

Allowance for Funds During Construction, E =	$	-	(Assumed zero for SNCR)	
Royalty Allowance,F =	$	-	(Assumed zero for SNCR)	
Preproduction Costs, G =	$	43,435.17		
=		2%	of D + E	
Inventory Capital, H =	$	169,732.64	= $Vol_{reagent}$(gal) x $Cost_{reagent}$($/gal)	
$Vol_{reagent}$ =		50,100	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 =	$	2,384,926.48	= 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. A small amount is accounted for on summary tab.

<u>Maintenance:</u>

1.5% of TCI
Maintenance = $ 35,774

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 =	\$	170,199	$= q_{sol} \times cost_{reagent} \times t_{op}$

Utilities:

Power Consumption, P:

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

NOx_{in}, (uncontrolled)=		0.31	lb/MMBtu
NSR (Normalized Stoichiometric Ratio):		1.92	
Q_B, boiler heat input=		156	MMBtu/hr
P =		5	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} =	\$	3,590	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} =		0.026	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)
	\$	3,440.63	

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

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

$$\Delta Fuel\left(\frac{MMBtu}{hr}\right) = 0.2205$$

Annual cost for additional fuel:

Additional fuel required:

Natural gas	0.22045	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)
	\$	18,230.05	\$/yr
Total Natural gas:	\$	18,230.05	
Additional Energy Requirement =	\$	3,873,506	(Additional heating of exhaust gas required for SNCR operations.)
Total DAC =	\$	4,104,739.99	

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 \$) =	\$	2,384,926.48
IDAC =	\$	242,910.03

Total Annual Cost (2022 \$):
Total Annual Cost, TAC = DAC + IDAC = \$ 4,347,650.03

COMPANY: United State Steel
LOCATION: Clairton
Source: T2 Boiler
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	**156**
NOX Removal Efficiency, η_{NOx}	**45%**
Cost Year	**2022**
Incremental Utility Requirements	
Electricity, kw	**5**
Reagent sol, gal/hr	**5.73**
Water, 1,000 gal/hr	**0.03**
NG, MMBtu/hr	**0.22045**
Reagent Volume, gallons	**50,100**
Reagent Cost, $/gallon	**3.39**

E

COMPANY: United State Steel
LOCATION: Clairton
Source: T2 Boiler
NO_X Emission Control Option: SNCR (45% Efficiency)

TOTAL CAPITAL INVESTMENT		
Total Direct Capital Cost, DC	$	1,573,738
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	$	314,748
Project Contingency, C	$	283,273
Total Plant Cost, D (DC + IC + C)	$	2,171,759
Allowance for Funds During Constr., E	$	-
Royalty Allowance,F	$	-
Preproduction Costs, G	$	43,435
Inventory Capital, H	$	169,733
Initial Catalyst and Chemicals, I	$	-
TOTAL CAPITAL INVESTMENT, TCI (D+E+F+G+H+I)	**$**	**2,384,926**

TOTAL ANNUAL COST		
Direct Annual Costs		
Operating & Supervisory Labor	$38,325	
Maintenance	$35,774	
Reagent Consumption	$170,199	
Utilities	$3,590	
Water Consumption	$3,441	
Add'l Fuel Usage (Process related)	$18,230.05	
Auxiliary Equipment Requirements	$ 3,873,506	
(Auxiliary Heating Costs = Nat'l gas cost required to heat boiler exhaust up to SNCR required temperature.)		
Total Direct Annual Costs		$4,143,065
Indirect Annual Costs		
CRF	0.102	
Total IDAC (CRF x TCI)		$ 242,910
TOTAL ANNUAL COST, TAC (DAC + IDAC)		**$ 4,385,975**

COST EFFECTIVENESS	
NOX_{in}, lbs/MMBtu	0.31
Efficiency, %	45%
Boiler Heat Input, MMBtu/hr	156
Total Operating Time, hrs/yr	8760
NO_X removed, tpy	95.3
Cost Efficiency:	
\$/ton NO_X removed	**$46,014**

Data Inputs

Select the type of oxidizer: Regenerative Thermal Oxidizer

Enter the following information for your emission source:

Composition of Inlet Gas Stream				
Pollutant Name	Concentration (ppmv)	Lower Explosive Limit (LEL) (ppmv)*	Heat of Combustion (Btu/scf)	Molecular Weight
Benzene	280	14,000	3,475	78.11

(280 ppmv set based on 6.07 tpy VOC limitation for the process and assumed flowrate)

Note: The lower explosion limit (LEL), heat of combustion and molecular weight for some commonly used VOC/HAP are provided in the table below. In addition, the heat of combustion to be entered in column D is a lower heating value (LHV), not a higher heating value (HHV).

Enter the design data for the proposed oxidizer:

Percent Energy Recovery (HR) = 70 percent

Number of operating hours/year	8,760	hours/year	
Inlet volumetric flow rate(Q_{wi}) at 77°F and 1 atm.	20,000	scfm*	* 20,000 scfm is a default volumetric flow rate. User should enter actual value, if known.
Pressure drop (ΔP)	19	inches of water	* 19 inches of water is a default pressure drop for thermal oxidizers. User should enter actual value, if known.
Motor/Fan Efficiency (ε)	60	percent*	* 60% is a default fan efficiency. User should enter actual value, if known.
Inlet Waste Gas Temperature (T_{wi})	60	°F	
Operating Temperature (T_{fi})	1,900	°F	* Note: Default value for Tfi is 2000°F for thermal regenerative oxidizers. Use actual value if known. Tfi for regenerative oxidizers typically between 1800 and 2000°F.
Destruction and Removal Efficiency (DRE)	98	percent	
Estimated Equipment Life	20	Years*	* 20 years is the typical equipment life. User should enter actual value, if known.
Heat Loss (η)	1	percent*	* 1 percent is a default value for the heat loss. User should enter actual value, if known. Heat loss is typically between 0.2 and 1.5%.

Enter the cost data:

Desired dollar-year	2022				
CEPCI* for 2022	824.5	Enter the CEPCI value for 2022	536.4	2016 CEPCI	*Enter dollar year first.
Annual Interest Rate (i)	8.00	%	(U. S. Steel value based on recent cost analyses)		
Electricity ($Cost_{elect}$)	0.0894	$/kWh	(EIA Data Point)		
Natural Gas Fuel Cost ($Cost_{fuel}$)	0.0112506	$/scf	(EIA Data Point)		
Operator Labor Rate	$70.00	per hour	(U. S. Steel labor rate)		
Maintenance Labor rate	$27.40	per hour			* $27.40 per hour is a default labor rate. User should enter actual value, if known.
Contingency Factor (CF)	10.0	Percent			* 10 percent of the total capital investment F45is a default value for construction contingencies. User may enter values between 5 and 15 percent.

* CEPCI is the Chemical Engineering Plant Cost Escalation/De-escalation Index. The use of CEPCI in this spreadsheet is not an endorsement of the index for purposes of cost escalation or de-escalation, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Data Sources for Default Values Used in Calculations:

Parameters for Common Compounds:

Compound	LEL (ppmv)	Heat of Combustion (Btu/scf)	Molecular Weight
Methane*	50,000	911	16.04
Ethane	30,000	1,631	30.07
Propane	21,000	2,353	44.09
Butane	19,000	3,101	58.12
Pentane	14,000	3,709	72.15
Hexane	11,000	4,404	86.17
Octane	10,000	5,796	114.23
Nonane	8,000	6,493	128.25
Decane	8,000	7,190	142.28
Ethylene**	27,000	1,499	28.05
Propylene	20,000	2,182	42.08
Cyclohexane	13,000	4,180	84.16
Benzene**	14,000	3,475	78.11
Toluene**	11,000	4,274	92.14
Methyl Chloride (Chloromethane)**	82,500	705	50.49

Footnotes
* Greenhouse gas.
** Hazardous air pollutant.

Data Element	Default Value	Sources for Default Values used in the calculation . . .	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Electricity Cost ($/kWh)	0.0641	Average annual electricity cost for industrial plants is based on 2016 price data compiled by the U.S. Energy Information Administration from data reported on Form EIA-861 and 861S, (https://www.eia.gov/electricity/annual/html/epa_02_04.html).		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at http://www.eia.gov/electricity/data.cfm#sales.
Fuel Cost ($/Mscf)	3.51	Annual average price paid for natural gas by industrial facilities in 2016 from the U.S. Energy Information Administration. Available at http://www.eia.gov/dnav/ng/hist/n3035us3A.htm.		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/dnav/ng/hist/n3035us3A.htm.
Operator Labor ($/hour)	26.61	Bureau of Labor Statistics, May 2016 National Occupational Employment and Wage Estimates – United States, May 2016 (https://www.bls.gov/oes/current/oes_nat.htm). Hourly rates for operators based on data for plant and System Operators – other (51-8099).		Use plant-specific labor rate.
Maintenance Labor ($/hour)	27.40	Bureau of Labor Statistics, May 2016 National Occupational Employment and Wage Estimates – United States, May 2016 (https://www.bls.gov/oes/current/oes_nat.htm). Hourly rates for maintenance workers based on electrical and electronics commercial and industrial equipment repairers (49-2094).		Use plant-specific labor rate.

Cost Estimate

Direct Costs

Total Purchased equipment costs (in 2022 dollars)

Incinerator + auxiliary equipment[a] (A) =		
Equipment Costs (EC) for Regenerative Oxidizer	=(2.204 x 100,000 + 11.57 Qtot) x (2022 CEPI/1999 CEPCI) =	$840,075 in 2022 dollars
Instrumentation[b] =	0.10 × A =	$84,008
Sales taxes =	0.03 × A =	$25,202
Freight =	0.05 × A =	$42,004
	Total Purchased equipment costs (B) =	$991,289 in 2022 dollars

Footnotes

a - Auxiliary equipment includes equipment (e.g., duct work) normally not included with unit furnished by incinerator vendor.

b - Includes the instrumentation and controls furnished by the incinerator vendor.

Direct Installation Costs (in 2022 dollars)

Foundations and Supports =	0.08 × B =	$79,303
Handling and Erection =	0.14 × B =	$138,780
Electrical =	0.04 × B =	$39,652
Piping =	0.02 × B =	$19,826
Insulation for Ductwork =	0.01 × B =	$9,913
Painting =	0.01 × B =	$9,913
Site Preparation (SP) =		$0
Buildings (Bldg) =		$0
	Total Direct Installaton Costs =	$297,387
Total Direct Costs (DC) =	B + C + SP + Bldg =	$1,288,675 in 2022 dollars

Total Indirect Installation Costs (in 2022 dollars)

Engineering =	0.10 × B =	$99,129
Construction and field expenses =	0.05 × B =	$49,564
Contractor fees =	0.10 × B =	$99,129
Start-up =	0.02 × B =	$19,826
Performance test =	0.01 × B =	$9,913
	Total Indirect Costs (IC) =	$277,561
Continency Cost (C) =	CF(IC+DC)=	$156,624
Total Capital Investment =	**DC + IC +C =**	**$1,722,860 in 2022 dollars**

Direct Annual Costs

Annual Electricity Cost	= Annual Electricity Usage × Operating Hours/year × Electricity Price =	$58,031
Annual Fuel Costs for Natural Gas	= $Cost_{fuel}$ × Fuel Usage Rate × 60 min/hr × Operating hours/year	$225,402
Operating Labor	Operator = 0.5hours/shift × Labor Rate × (Operating hours/8 hours/shift)	$38,325
	Supervisor = 15% of Operator	$5,749
Maintenance Costs	Labor = 0.5 hours/shift × Labor Rate × (Operating Hours/8 hours/shift)	$15,002
	Materials = 100% of maintenance labor	$15,002
Direct Annual Costs (DC) =		**$357,510 in 2022 dollars**

Indirect Annual Costs

Overhead	= 60% of sum of operating, supervisor, maintenance labor and maintenance materials	$44,446
Administrative Charges	= 2% of TCI	$34,457
Property Taxes	= 1% of TCI	$17,229
Insurance	= 1% of TCI	$17,229
Capital Recovery	= CRF[TCI-1.08(cat. Cost)]	$175,477
Indirect Annual Costs (IC) =		**$288,838 in 2022 dollars**
Total Annual Cost =	**DC + IC =**	**$646,348 in 2022 dollars**

Cost Effectiveness

Cost Effectiveness = (Total Annual Cost)/(Annual Quantity of VOC/HAP Pollutants Destroyed)

Total Annual Cost (TAC) =	$646,348	per year in 2022 dollars
VOC/HAP Pollutants Destroyed =	5.9	tons/year
Cost Effectiveness =	$108,659	per ton of pollutants removed in 2022 dollars